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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF OWEN ELECTRIC COOPERATIVE, INC. FOR AN ADJUSTMENT OF RATES	)))	Case No. 2011-00037

ATTORNEY GENERAL'S REPSONSE TO DATA REQUESTS FROM OWEN ELECTRIC COOPERATIVE, INC.

Comes now the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and tenders his responses to the Data Requests tendered by Owen Electric Cooperative, Inc.

Respectfully submitted,

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Certificate of Service and Filing

Counsel certifies that an original and ten photocopies of the foregoing were served and filed by hand delivery to Jeff Derouen, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; counsel further states that true and accurate copies of the foregoing were mailed via First Class U.S. Mail, postage pre-paid, to:

Hon. James M. Crawford
Crawford and Baxter, P.S.C.
523 Highland Avenue
P.O. Box 353
Carrollton, KY 41008

Mark Stallons
President
Owen Electric Cooperative, Inc.
P. O. Box 400
Owenton, KY 40359

this 26th day of September, 2011.

Assistant Attorney General

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins

QUESTION 1:

With regard to the Attorney General's Prefiled Testimony of Mr. Glenn A. Watkins (hereinafter "Watkins testimony"), Page 2, Line 26-27, and Page 3, Lines 1-3, wherein he states:

a. "Owen's proposed Residential Schedule I rate design directly conflicts with sound economic principles." Please explain how this rate directly conflicts with sound economic principles when Economic Principles state that in a natural monopoly (one with economies of scale such as Owen), pricing is where price equals average total cost (ATC), not when price equals marginal cost. This is because when price is equal to marginal cost, losses can occur. In the rate design proposed, the customer charge is the average total cost of providing basic service and any charges above that is the cost of providing kWh's. How is this not sound economics?
b. Long established rate making policy (volumetric based) has not encouraged conservation to any large degree. Given this, does Watkins agree or disagree whether the current rate making policy needs to be altered? Why or why not?
    1) In an ever-changing world, does reevaluating and possibly changing the methods of old not lead to new innovations and efficiency and possibly a new outcome?
    2) Does Watkins contend he is qualified to say that without a doubt, altering the long established rate making policy will not lead to a better financial situation for an electric utility because it will not have to rely on energy sales for financial stability? Why or why not?
c. What qualifications does Watkins have to say what is or is not in the public's best interest?

    1) Economic principles make behavioral assumptions that we are rational decisions makers. Please provide studies supporting Watkins contention that such a rate plan is not in the public interest.

WITNESS RESPONSIBLE:
Glenn Watkins
QUESTION 1

RESPONSE:

a. Please refer to Mr. Watkins direct testimony, page 6, line 1 through page 9, line 15.

b. Objection, argumentative. Without waiving this objection, this request is predicated on an argument. Mr. Watkins does not agree with this argument, therefore, the remainder of the request is moot.

   1) The request is too broad, general and vague to provide any meaningful response.

   2) There are many factors influencing a utility's "financial situation" including management effectiveness, capital structure, dividend or capital credit payouts, the need and uncertainties of growth, infrastructure replacement, and economic climate, regulatory policies and directives, etc. However, all else constant, Mr. Watkins would agree that if a regulatory commission were to guarantee a utility's revenue collection through unavoidable fixed monthly charges, the utility's risk would be reduced which would then add to the utility's "financial situation." Similarly, if a regulatory Commission established rates that provide a rate of return above the risks confronted, the utility's "financial situation" would also be improved.

c. Please see Mr. Watkins testimony, page 1, lines 14 through 30, and his Schedule GAW-1.

   1) Please refer to Mr. Watkins entire testimony.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 2:

With regard to Watkins testimony, Page 3, Line 9, wherein he states:

a. "Owen's proposed rate changes for its residential customers charges are not revenue neutral." How is it not revenue neutral for this rate class? Provide calculations to support your position.

RESPONSE:

a. As clearly indicated in Mr. Watkins's testimony on page 3, lines 5 through 17, he does not claim that Owen's rate design proposal is not revenue neutral on a total Cooperative basis, but rather, is not revenue neutral for all customers as explained in his testimony.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 3:

With regard to Watkins testimony, Page 3, Lines 22-26, please provide the numerical increase or decrease and the corresponding percentage differences for residential consumers in an annual bill for users on 100 kWh increments from 800 kWh to 2800 kWh.

RESPONSE:

Mr. Watkins has not conducted the requested analysis. Owen is capable of calculating bill impacts based on its own proposal.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 4:

With regard to Watkins testimony, Page 3, Line 28, where Watkins references the testimony of Mark Stallons, please identify the page and line number where exact quote or quotes were made.

RESPONSE:

Page 4, Q. 15;
Page 4, Q. 16; and,
Page 4, Q. 17.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 2

QUESTION 5:

With regard to Watkins testimony, Page 4, Lines 10-29, wherein he states:

a. That "Virtually every electric utility in the nation relies upon a rate structure that is overwhelmingly volumetrically based. Indeed, for decades the pricing structures of electric utilities have been largely volumetric based. This industry has remained not only financially viable, but has grown and prospered throughout the Country under volumetric rates for decades and continues to do so."
    1) Does Watkins agree, then, that the electric industry should continue to follow this historical rate structure based on volume in the current era of increased pressure for energy conservation, efficiency, environmental concerns, EPA rulings and declining disposable income so to stay viable, grow and prosper? Why or why not?
    2) Does Watkins believe volumetric sales should be the goal of electric utilities? If not, how should the rate structure be designed so that the Cooperative stays prosperous and viable as a going concern? Please support you answer.
    3) Does Watkins agree that frequent rate case increases are the most efficient tool to achieve reasonable margins for the Cooperative? Why or why not?
    4) Does Watkins believe that frequent rate case increases are the proper approach to minimize Cooperative's costs, increase member satisfaction, and to uphold Cooperative principles? Why or why not?
b. Why do you believe that Owen is unique in its approach in this case when there have been several studies advocating a higher customer charge? Is Owen not following current best practices as sighted in attachments to Owen's response to Question 2 of the Commission Staff's Second Information Request? If no, then explain which "best practices" are not being followed.

WITNESS RESPONSIBLE:
Glenn Watkins
QUESTION 5

RESPONSE:

a. 1) Yes. Please refer to Mr. Watkins' entire testimony.

2) Mr. Watkins is unsure of the question as it relates to a "goal." However, Mr. Watkins is of the opinion that a pricing structure based predominately on volumetric pricing is in the best public interest and should be maintained. Please see Mr. Watkins' entire testimony for the reasons.

3) Objection, relevance. The question as posed exceeds the scope of Mr. Watkins' testimony and the issues presented in the instant case. Without waiving this objection, the question is impossible to answer as there are a multitude of factors that give rise to the need for rate cases and these factors vary on a case by case basis.

4) Objection, relevance. The question as posed exceeds the scope of Mr. Watkins' testimony and the issues presented in the instant case. Without waiving this objection, does not agree. The ratemaking regulatory process itself has nothing to do with a cooperative's ability to minimize costs, or change member satisfaction. It is not understood what is meant by the "uphold[ing]" of a cooperative's principles.

b. Mr. Watkins has not claimed that Owen is unique in its approach in this case. Indeed, several utilities (primarily natural gas) have proposed largely fixed rate structures around the country. Mr. Watkins is of the opinion that a rate structure comprised heavily on fixed charges does not constitute "best practices." Please see Mr. Watkins' entire testimony as to the reasons why.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 6:

With regard to Watkins testimony, Page 5, Lines 8-11, wherein he refers to "the laws of physics dictate." Please cite law of physics referred to in his testimony and state how do the laws of physics impact economic theory and pricing based on marginal costs or electric appliance efficiencies?

RESPONSE:

The statement is general in nature and is self explanatory. Please also refer to Mr. Watkins testimony, page 5, lines 1 through 8. The laws of physics impact economic theory and pricing based on the demand for a product or service and a firm's production (cost) function.

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 7:

With regard to Watkins testimony, Page 5, Lines 1-27, wherein he refers to the increased efficiency gains offset with the increased use of electric devices, does he believe that consumers will reach a point where the price of electricity will switch from inelastic to elastic? Why or why not?

a. Does Watkins believe we are going to quickly approach this price point since the price of electricity is forecasted to increase exponentially in Kentucky over the next few years due to environmental regulations and standards?
b. When this price point is met, does Watkins believe usage will decline and could potentially damage the financial stability of Owen? If so, are costly and frequent rate increases the solution to offset the financial loss? If it is not, what does he believe is?

RESPONSE:

7. No. While economic theory tells us there is a point (price) along demand curve in which the price elasticity of demand will change from inelastic to elastic, it is generally agreed that the demand curve for electricity is so flat (at least for residential and commercial consumers) that the inflection point is beyond any range of reasonable probability. As such, the demand for electricity is universally considered inelastic.

   a. Please see response above.

   b. Please see response above.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 8:

With regard to Watkins statement on Page 5, Line 9, "that electric appliances have largely reached a point of diminishing efficiency gains"

a. Has Watkins considered the impact of smart appliances and home energy networks in automated energy efficiency improvement in the appliance area?
b. If so, what is Watkins' opinion regarding the potential impact of smart appliances and home energy networks on household energy efficiency?
c. Has Watkins considered the impact of pre-pay metering technology and the 12% improvement in energy efficiency claimed by utilities utilizing pre-pay systems?
d. Does Watkins have any measured opinion in regards to whether home energy networks combined with smart appliances would yield similar 12% energy efficiency improvements?

RESPONSE:

a. Yes.

b. It is Mr. Watkins understanding that so called "smart appliances" and "home energy networks" will increase appliance efficiency and that these efficiency gains will vary by appliance. Energy savings realized will depend on saturation and consumer use of specific appliances.

c. No.

d. No.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 9:

With regard to Watkins testimony, Page 5, Line 12, wherein he states that "it is highly unlikely that Owen's Residential customers will significantly reduce their total electricity consumption to any material degree in the next several years".

a. Please provide support of this statement in the form of published studies, analysis, programs, or evaluations.

RESPONSE:

a. Residential energy usage per capacity has continued to rise consistently since World War II. As Americans (including Owen's ratepayers) continue to use more and more electric devises with more frequency, this trend is expected to continue. Please also see the attached studies:

   "Changing Trends: A Brief History of the Household Consumption of Energy, Water, Food, Beverage, and Tobacco" (Attachment 1); and,

   "Regional Differences Into Price Elasticity of Demand for Energy" (Attachment 2).

WATKIN'S RESPONSE TO OWEN
QUESTION 9

ATTACHMENT 1

Changing Trends: A Brief History of the US Household Consumption of Energy, Water, Food, Beverages and Tobacco

Rick Diamond and Mithra Moezzi, Lawrence Berkeley National Laboratory

ABSTRACT

Can an historic analysis of consumption patterns of different commodities in the U.S. shed light on the consumption of energy used in homes and passenger cars? Can a review of past policies to reduce or change consumption patterns provide insight or guidance in developing new policies for reducing energy use? In order to better understand energy conservation policies, we take a brief look at the history in the US of consumption of different commodities, including residential energy, passenger car, household water, food, beverages and tobacco. While current policy makers appear reluctant to pursue strategies to reduce absolute energy consumption, there is a long history of government efforts to influence consumption of other commodities, through a variety of means, e.g., prohibition, exhortation, subsidy, regulation, and taxation. By reviewing the trends in historic consumption we see examples of where policy has led to increases and decreases in consumption, suggesting parallel strategies for promoting the long-term conservation of energy.

Introduction

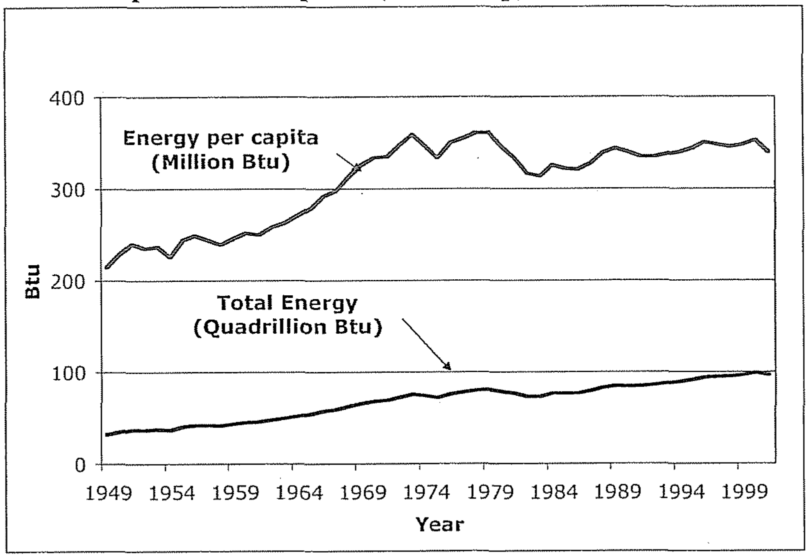
We start by looking at historical consumption data and ask questions about the social and political forces that have led to increases and decreases in consumption. In many cases the historical data have been difficult to characterize, due to changes in definition, gaps in data collection, and inherent bias in the data due to private interests providing "public" data, e.g., USDA data on food consumption is supported by several powerful food industries. We look briefly at the historic trends in household and per capita consumption of energy and water, and also at food, beverages, and tobacco, products that have been the subject of social and political experiments in promotion, curtailment and conservation. And while we raise more questions than we answer, we feel the approach of asking questions to be fruitful in giving us insights in where to focus our attention in looking at policies that can lead to reduction in energy consumption.

Patterns of Consumption—Historic Trends

Electricity & Gas

We'll start with historic US primary energy consumption from 1949 to 2001 (Figure 1). In 1949, U.S. energy use per person stood at 215 million Btu. The rate of consumption generally increased until the oil price shocks of the mid-1970s and early 1980s caused the pattern to reverse for a few years. Following a gradual increase from the mid 1980s, the rate fell 4 percent from 2000 to 2001.

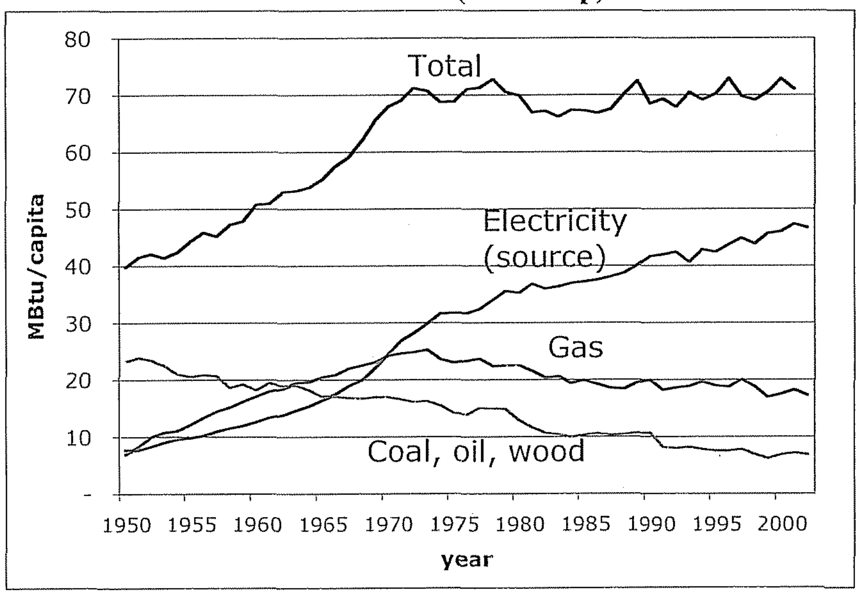
Figure 1. US Primary Energy Consumption, Total (Quads) and Per Capita Consumption (MBtu/cap) from 1949 to 2001



Source: EIA 2003

Such a figure invites several questions: Did per capita energy use increase from 1949 to 1973 due to bigger houses and cars, more appliances, more appliance usage, more energy intensive activities, air conditioning, etc.? Does this leveling off reflect a structural shift in the economy from manufacturing towards service? If we look at the historic trend in residential energy use per capita we see part of the story (Figure 2).

Figure 2. US Residential Energy Use Per Capita, Total, Electricity [Source], Gas and Other (MBtu/cap)

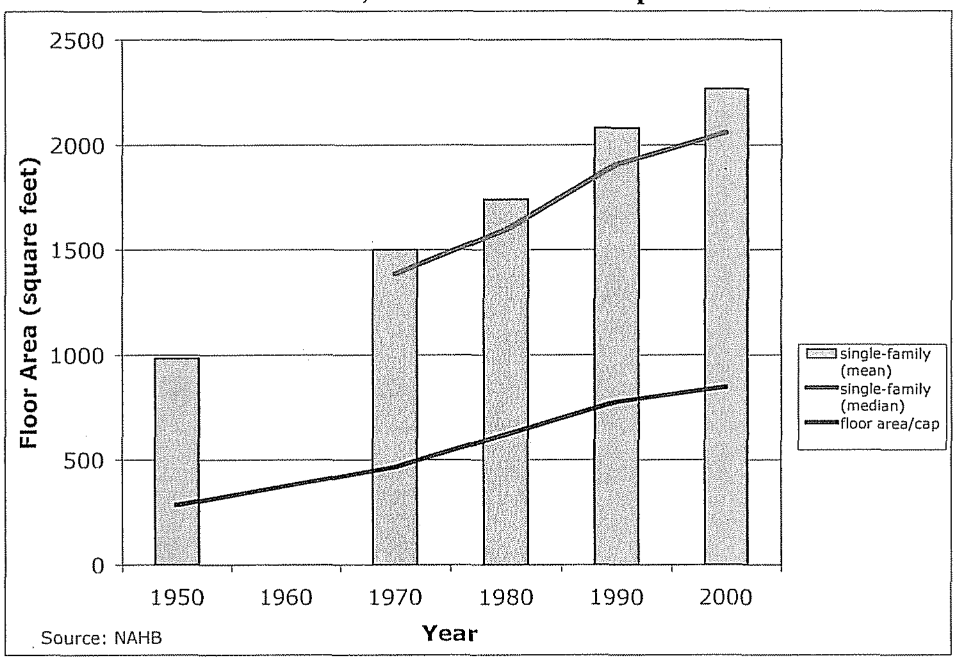


Source: EIA 2003

While the residential total per capita energy use shows the same leveling off as the US total energy use, residential gas use has declined since 1970 and electricity use has continued to increase. The decrease in gas use reflects the drop in energy for space heating and the shift to electricity (Battles 1995). The increase in electricity is due in part to greater air conditioning use (both in volume of space conditioned as well as hours of usage) as well as other appliance usage, switching from gas to electric (heat pumps, water heaters), and other factors, such as demographic shifts to the South (Schipper 1989). Governmental policies for rural electrification, e.g., the Tennessee Valley Authority, also subsidized electricity use and growth in the Southeast, Northwest and elsewhere (Cooper 1998).

If we look at the increase in house size over this time, as well as the increase in appliance saturation and usage, we can start to see additional drivers behind the increase. Figure 3 shows that average new house floor area has increased from 983 ft^2 in 1950 to 2266 ft^2 in 2000, more than doubling. As household size has decreased, the floor area per capita has increased by more than a factor of 3, from 286 ft^2 per capita in 1950 to 847 ft^2 per capita in 2000.

Figure 3. US New Single-Family Housing Floor Area (Square Feet) Mean, Median and Per Capita

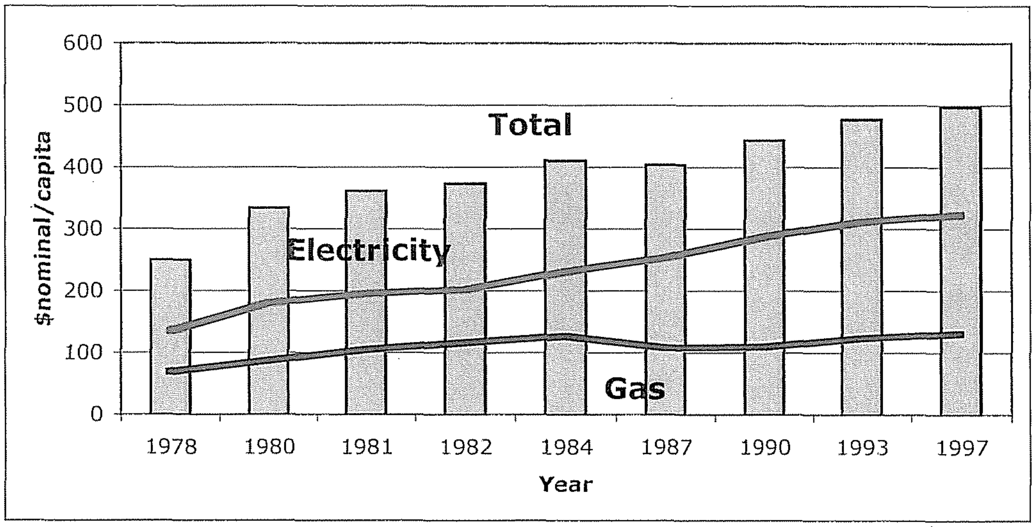


Source: NAHB, US Census

As new houses get bigger, there is more space to condition and more space for appliances and equipment. The market share of energy-efficient appliances may be increasing, but as we have seen, so is per capita electricity consumption. A question that we raise is whether people are increasing their purchase of appliances and equipment at the same rate as improvements in energy efficiency?

Figure 4 shows the annual residential energy expenditure for 1978 through 1997, with the total doubling over the time period, and with greater increases in electricity then in gas.

Figure 4. US Annual Residential Energy Expenditure 1978-1997
(Nominal dollars per capita)

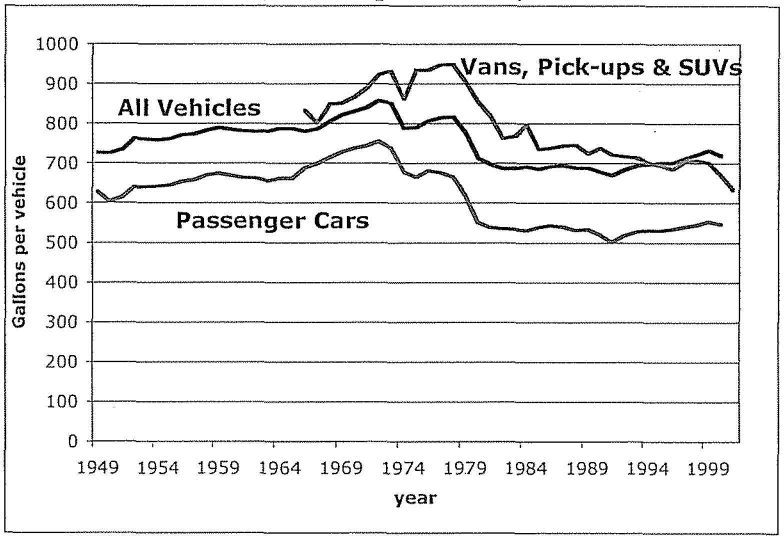


Source: EIA 2003

Gasoline for Passenger Cars

Figure 5 shows historic trend data for gasoline consumption (annual gallons per vehicle) for the fleet average for all vehicles, passenger cars, and vans, pick up trucks and SUVs. Gas consumption per vehicle rose slightly during the 50s and 60s then more sharply in the early 1970s prior to the oil shocks, dropped during the price increases of the 70s, and leveled off during the 80s and 90s, due to the increase in number of vehicles per household.

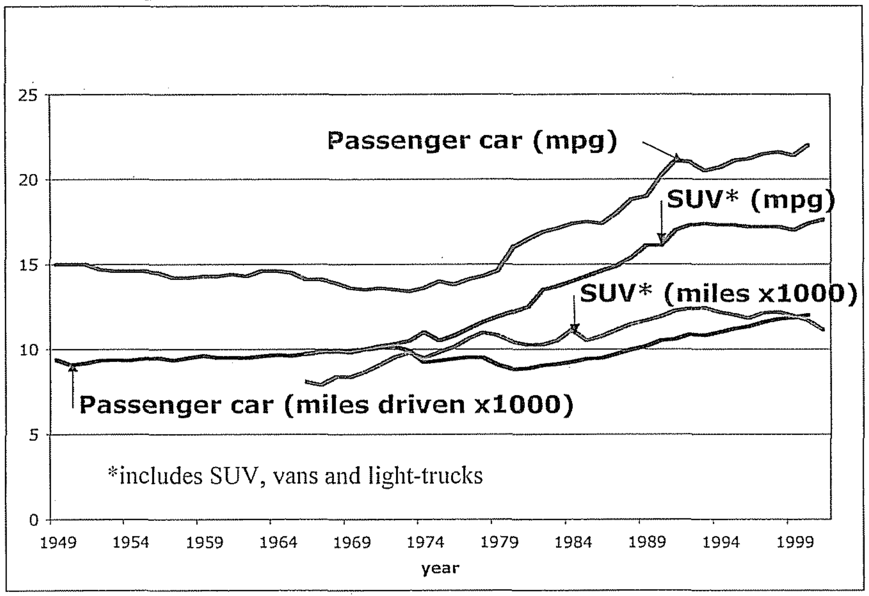
Figure 5. US Vehicle Gasoline Consumption 1949-2000
(Gallons per vehicle)



Source: EIA 2003

Figure 6 shows two of the drivers underlying gas consumption for both passenger cars and vans, pick-up trucks and SUVs: the increase in both the miles driven per passenger vehicle (mileage) and the increase in fuel efficiency (miles per gallon). What is not shown in Figure 6 is that SUVs, vans and light-pick-up trucks now account for over 50% of new vehicles.

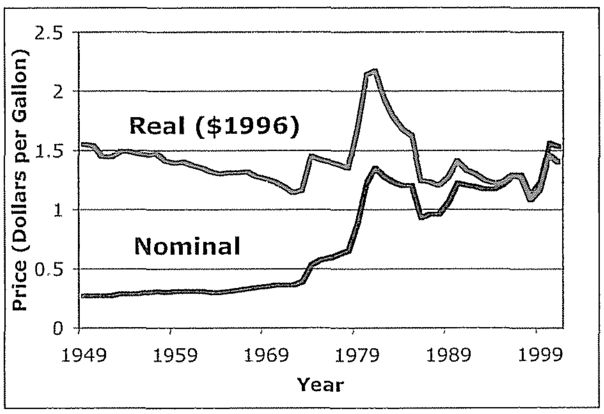
Figure 6. Passenger & SUV Fuel Efficiency and Vehicle Mileage 1949-2000



Source: EIA 2003

The findings here are that passenger car fuel efficiency was remarkably flat at 15 miles per gallon from 1950 until the mid 60s and after actually decreasing for a few years, then increased to meet the new standards. Vehicle mileage was also remarkably flat during this historic period and started increasing in the 1980s. When we look at the 50-year trend in gasoline prices (real), they have remained flat, around $1.50 per gallon, with the exception of the price spikes in the early 1980s due to the oil embargoes (Figure 7). The recent (Summer 2004) escalation in gas prices will be a significant departure from this historic trend.

Figure 7. US Retail Motor Gasoline Price (dollars per gallon) 1949-2001



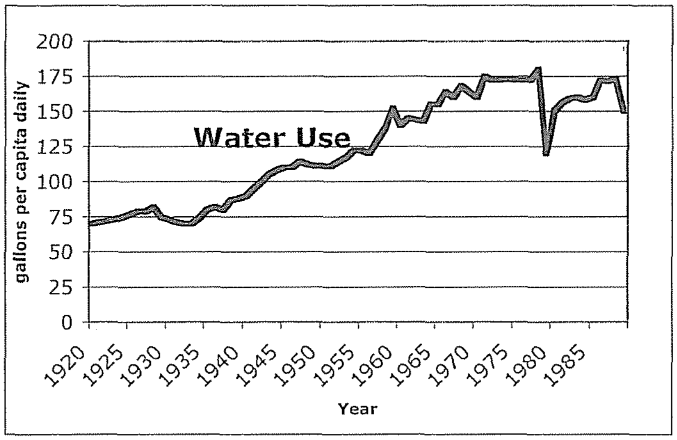
Source: EIA 2003

Household Water

Household water consumption is an interesting parallel to household energy consumption in that the monthly expenditures are similar in much of the US. Like energy, water is metered (generally) and households pay a monthly or bi-monthly bill. And similar to energy, most households have no idea of how much water they use and how they use it.

From the beginning of this century until 1970, urban per capita water use increased steadily, as illustrated by Figure 8, which charts increases in per capita water use in the San Francisco Bay Area (California 1993). Because most residential urban water use is for landscape watering, weather variations affect water use significantly from one year to the next. The trend towards fewer people per household, increases in household income, and population growth in warmer inland areas have tended to counteract the effects of multifamily housing and conservation, which drive per capita water use downward. Large reductions in per-capita water use are pronounced during drought years when aggressive short-term conservation and rationing programs are in effect. In the long term, permanent water conservation programs and other factors have begun to reduce overall per capita water use in some areas (California 1993).

Figure 8. Urban Per Capita Water Use (daily gallons per capita), San Francisco Bay Area, 1920-1990



Source: California 1993

The effort to conserve urban water has paralleled the energy conservation/efficiency activities of the past 20 years, with demand-side management programs, education, rebates, incentives, etc., following much the same pattern as the energy utilities and municipalities. One significant difference is the lack of overall data on water use and end use. Another difference is the lower expectations for conservation. The 1990 projection for the San Francisco Hydrologic Region urban residential water use was a 7% reduction by 2020, from 106 gallons per day per capita (gpcd) to 98 gpcd, due to best management practices. A 7% reduction over 30 years is a pretty modest goal—much less stringent then federal energy standards, e.g., 30% reduction in 25 years. But water in much of the US is relatively cheap—households in California pay an average of $1.80 for a thousand gallons of tap water, nearly the same price as for *one* gallon of bottled water. Government subsidies of water play out not only on the household level, but across all sectors of the economy, with large subsidies for agribusiness and industry.

Food Consumption

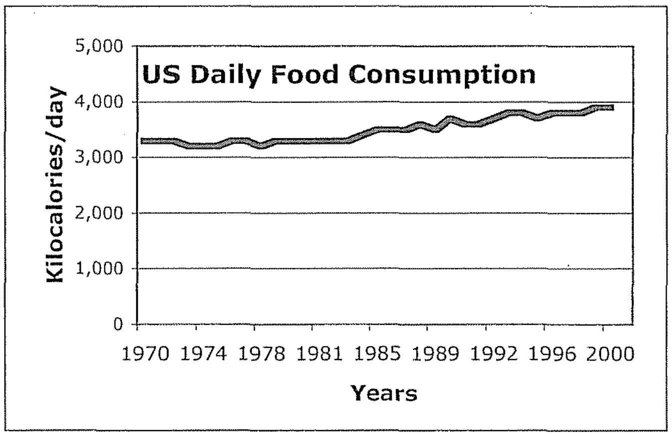
Evidence from various sources suggests that Americans now consume, on average, more total food, more snacks, bigger portions of food, and more calories than they did 30 years ago (Putnam 1999). A variety of factors are responsible for the changes in US food consumption patterns in the last 30 years, including changes in relative food process, increases in real disposable income, and more food assistance for the poor. New products, particularly more convenient ones, along with more imports, growth in the away-from-home food sector, expanded advertising programs and changes in food enrichment standards and fortification policy. Socio-demographic trends also driving food choices include smaller households, more two-earner households, more single-parent households, an aging population and increased ethnic diversity. New dietary guidelines designed to help people make food choices to promote health and prevent disease, improved nutrition labeling and increased awareness of nutrition also influence marketing and consumption trends (Putnam 1999).

Demand for food in the aggregate is not very responsive to price changes, because there is little room for substitution between food and non-food items. However, demand for individual foods is more responsive to prices as consumers substitute among alternative food commodities.

Internationally, Americans spend the least on food in relation to per capita consumption, 7% of personal consumption expenditure for food eaten at home. This figure compares with 10% in Canada and 11% in the UK and over 50% for India or Philippines (Putnam 1999.)

The level of food energy in the US food supply increased from 3300 calories per capita per day in 1970 to 3900 calories in 2000 (Figure 9). This 15% increase reflects higher levels of all three food groups, carbohydrates (grains & sweeteners), fats and proteins (grains, poultry & cheese). Total calories in 1909 is estimated at 3400 kilocalories/day, so the level was flat for several decades before the recent increase.

Figure 9. US Per Capita Food Consumption (Kilocalories per day)



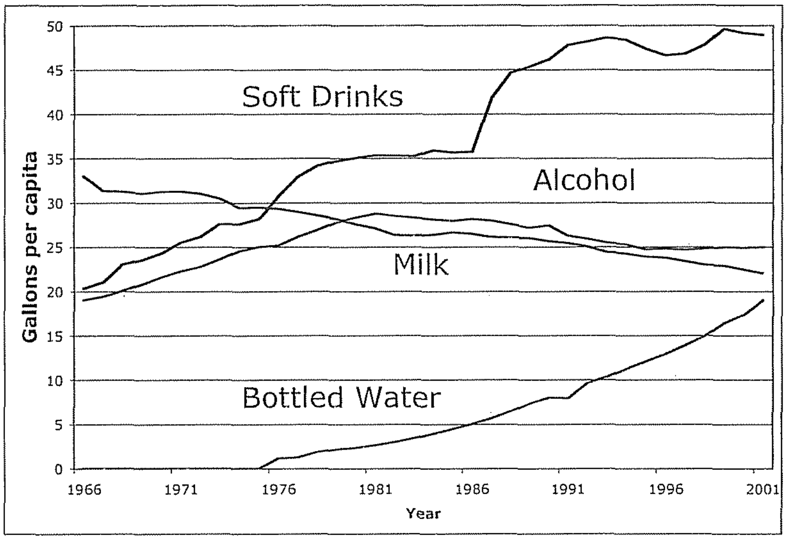
Source: USDA 2002

Policies such as the USDA food pyramid that are subject to extensive lobbying from the meat. cereal, dairy and sugar industry, and cutbacks in school lunch programs and physical fitness programs are also factors in the growing rate of obesity in children, with exposure to TV advertising being perhaps the single largest factor (Willett 2002).

Beverage Consumption

Beverages provide an example of how government subsidies, marketing and other forces change patterns and trend of consumption. Consumption of beverages has changed dramatically in the US over the past 40 years (Figure 10). In 1945, Americans drank more than four times as much milk as carbonated soft drinks; in 1997, they downed nearly two and a half times more soda than milk. Milk consumption has decreased, alcohol consumption has leveled off and decreased slightly and soft drinks and bottled water have increased dramatically. The reasons for the increase in soft drink consumption have been advertising and heavy subsidies to the producers of corn syrup, which surpassed cane and beet sugar for the first time in 1985 (Putnam 1999). Apparently the "Got Milk" advertising, despite their clever sales pitches, has not been able to reverse the decline in whole milk sales, although other milk products have increased.

Figure 10. US Beverage Consumption (gallons per capita) 1967-2001



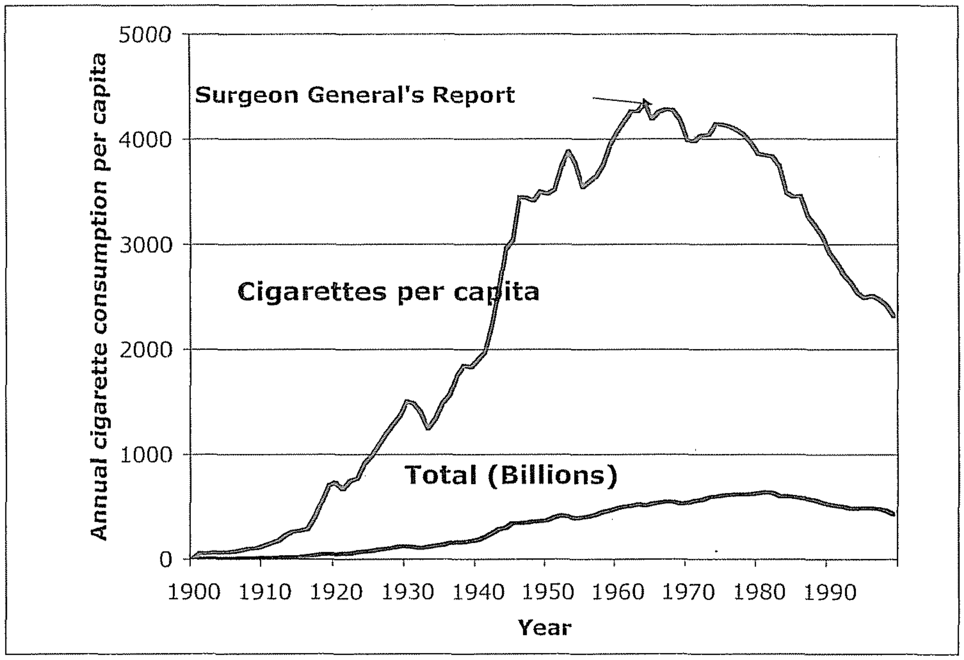
Source: USDA

Tobacco

One wouldn't generally compare the consumption of a commodity like tobacco with a commodity like energy, but if we are looking for examples of where government intervention seems to have led to a reduction in use, there are few cases as dramatic as cigarettes. Cigarette consumption increased dramatically in the first half of the 20th century, particularly during the two world wars. The turning point came in 1964 following the US Surgeon general's report on smoking (Figure 11).

Since 1990, though, the decline in the percent of adults who smoke has slowed. In 2000, 25 percent of men and 21 percent of women were smokers. If we are interested in how to break people of their "energy habit," it is worth noting that changing behavior is far more difficult than establishing "good" behavior initially. This is a special challenge for energy consumption, both because it is a continuous process, linked to myriad other choices but almost always indirect, and because energy (unlike water) is not consumed for itself, but as an integral part of several activities, many of which do not change quickly.

Figure 11. Total and Per Capita (Adults) Cigarette Consumption 1900-2000



Why Does Consumption Go Up?

If we want to be able to formulate policies that focus on reducing consumption of energy—or any good—it may help to understand the basis for why people consume in the first place. Basic consumption is needed for survival—shelter, fuel, food and clothing. But the levels of consumption seen by contemporary US culture vastly exceed any level for assuring that basic needs are met. Social scientists have written on the multiple reasons for why people consume beyond what they need for survival—e.g., for status, for pleasure, for display, convenience, marketing, etc. (Wilk 2002). A recurring phenomenon noted by several observes of the contemporary scene is that wants and desires become necessities.

Juliet Schor in her work, "The Overspent American" (Schor 1998), has made several observations on the motivations for contemporary American consumer culture:

> "In the old days, our neighbors set the standard for what we had to have. Today a person is more likely to be making comparisons with .. people whose incomes are significantly higher."

> "We are more likely to identify with the characters on "Friends" than with our real friends."

> "Consumer satisfaction depends less on what a person has in an absolute sense than on socially formed aspirations and expectations"

Schor also traces the changes from a set of early American values that held, thrift, sufficiency and modest consumption with changes in the wave of mass prosperity. "Spending, even spending to excess, was extolled as good for the ego, if not for the soul. Consumerism became the new, therapeutic belief system. Religious, legal, and folk impediments to consumption declined markedly. Most insidious of all, aggressive spending was made patriotic. It spread the wealth, we were told, creating jobs for the unemployed as well as profits for American industry" (Schor 1998). Anthropologist Willett Kempton notes that from an environmental perspective, a problem with consumption to display social status is that status is always relative, generating an unending spiral of increasing consumption, display and recomparison (Kempton 2001).

When Does Consumption Go Down?

Is the general pattern that we always consume more and more of everything, or are their cases when consumption drops? And in those cases, is it the direct result of policies, or shifts in societal and economic forces? One of the goals of American energy policy is to increase efficiency, not to decrease energy consumption, although decreased consumption is implied in carbon-emissions reductions objectives. Efficiency achievements are typically stated in terms of avoided energy consumption, calculated as energy savings relative to a (necessarily) abstract baseline. But energy efficiency policy generally addresses efficiency on an end use by end use, technology by technology, rather than on a more aggregate (for example, societal) basis. In this sense, achieving absolute reductions in overall or per capita energy consumption *is not* the goal of energy policy. There is also the moral argument for reducing consumption, which we do not review here (Rudin 2002).

While policy makers and politicians may not care to admit it, there have always been numerous ways in which government influences the consumption of products and materials, favoring increases in some commodities while instituting practices that lead to decreases in others. As a quick—but not exhaustive—review, here are several policies for reducing consumption, both mandatory measure and voluntary measures, using water conservation as a model (Renwick 1998).

Mandatory policy measures:

Rationing programs generally allocate a fixed quantity of water to households, based on some allocation criteria, and impose penalties for exceeding the allotment, such as severe marginal price penalties.

Restrictions on water use constitute a more precise form of rationing. Use restrictions place constraints on when certain types of water use practices can occur, such as no washing down sidewalks or driveways, or bans on landscape irrigation during peak evapo-transpiration hours. During the 1990-1991 drought, Santa Barbara banned nearly all forms of irrigation and hired "water police" to enforce the policy.

Compliance measures. The SF Water Department adopted a compliance affidavit program. Households were required to file an affidavit attesting that specific water-efficient devices were employed. Those that did not faced higher marginal prices.

Voluntary Measures

Information. Public information campaigns to alert households to shortages, to motivate more efficient water behavior, and to provide information on means to reduce usage.

Rebates. Subsidies to encourage adoption of water-efficient technologies, such as ultra low-flow toilets, horizontal-axis washing machines.

Retrofits. Distribution of free retrofit kits, including low-flow showerheads, tank displacement devices and dye tablets for leak detection.

Some economists would argue that these policies are unnecessary; if people paid the true cost of water [or energy], then these actions would not be needed. Economic theory also suggests that residential water demand should be price inelastic for three reasons: 1) there exists no close substitutes for water in most of its uses, 2) the amount of money spent on water is a relatively small share of the typical household budget, and 3) water is frequently demanded jointly with some other complementary good, e.g., clothes or dish washing.

An interesting parallel with energy use is the observation that the use of price as an allocation mechanism is constrained by the fact that water is generally regarded as a basic necessity, even as a right, not an economic good (Renwick, 1988). But, in contrast to energy, policy makers are *willing to talk about conservation* of water, *not just efficiency.*

Conclusions: What is in the policy toolbox?

Our initial question was whether historical trend data would show the impact of policies to change consumption—and whether these policies would provide insight in shaping the current debate to reduce energy consumption. Based on the cursory review of the trend data included here, we have seen examples of where policies have led to both increases and decreases in consumption. These policies have had direct and indirect impacts on consumption. The types of policies we have seen include: **1) Standards & Regulation**, such as water and energy standards for new appliances and fuel ratings for new vehicles that lead to decreases in per unit consumption, vs. unregulation, as in the case of SUVs being exempt from stricter mileage standards and water consumption not metered in certain communities. **2) Taxes & Rebates**, which through tax breaks can lead to increases in consumption of some commodities or services, such as advertising, home mortgages, photovoltaic panels, etc., or to decreases, e.g., taxes on alcohol and tobacco, etc. **3) Subsidies**, as in the case of cheap corn syrup leading to increases in beverage consumption, or subsidized water used to grow rice in arid regions, or the subsidies for a variety of energy sources, e.g., oil, gas, wind, ethanol, nuclear, etc. **4) Procurement**, by which government leads by example and influences product design and durability, and **5) Education**, as in the example of the food industries' interests in promoting certain food groups, e.g., meat and dairy, vs. improved food labeling, and in the issuance of health advisories leading to the reduction of tobacco use.

What this review of the historical consumption data suggests is that government policies have often played a role in shaping consumption, and if policy makers are serious about reducing energy consumption, there is historic precedent and a range of strategies to pursue.

Acknowledgments

The authors would like to thank Jeffrey Harris, Bill Golove, and Evan Mills for their comments on an earlier draft of this paper. This work was supported by the Assistant Secretary for Energy Efficiency and Renewable Energy, Building Technologies Program, of the US Department of Energy under Contract No. DE-AC03-76SF00098, and by the California Energy Commission's PIER Program.

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WATKIN'S RESPONSE TO OWEN
QUESTION 9
ATTACHMENT 2

This product is part of the RAND Corporation technical report series. Reports may include research findings on a specific topic that is limited in scope; present discussions of the methodology employed in research; provide literature reviews, survey instruments, modeling exercises, guidelines for practitioners and research professionals, and supporting documentation; or deliver preliminary findings. All RAND reports undergo rigorous peer review to ensure that they meet high standards for research quality and objectivity.

TECHNICAL
REPORT

Regional Differences in the Price-Elasticity of Demand For Energy

Mark A. Bernstein, James Griffin

Prepared for the National Renewable Energy Laboratory

RAND INFRASTRUCTURE, SAFETY, AND ENVIRONMENT

The research described in this report was conducted under the auspices of the Environment, Energy, and Economic Development Program (EEED) within RAND Infrastructure, Safety, and Environment (ISE), a division of the RAND Corporation, for the National Renewable Energy Laboratory.

Published 2005 by the RAND Corporation
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Preface

About This Analysis

Each year, the Department of Energy (DOE) requires its research programs to estimate the benefits from their research activities. These estimates are part of the programs' annual budget submissions to the DOE, and they are also required under the Government Performance and Review Act. Each program in the DOE's Office of Energy Efficiency and Renewable Energy (EERE) is responsible for providing its own assessment of the impact of its technology research and development (R&D) programs. For the most part, the benefit estimates from each EERE program office are made at the national level, and the individual estimates are then integrated through the use of the National Energy Modeling System to generate an aggregate set of benefits from the EERE's various R&D programs.

At the request of the National Renewable Energy Laboratory (NREL), the RAND Corporation examined the relationship between energy demand and energy prices with the focus on whether the relationships between demand and price differ if these are examined at different levels of data resolution. In this case we compare national, regional, state, and electric utility levels of data resolution. This study is intended as a first step in helping NREL understand the impact that spatial disaggregation of data can have on estimating the impacts of their programs.

This report should be useful to analysts in NREL and other national laboratories, as well as to policy nationals at the national level. It may help them understand the complex relationships between demand and price and how these might vary across different locations in the United States.

The RAND Environment, Energy, and Economic Development Program

This research was conducted under the auspices of the Environment, Energy, and Economic Development Program (EEED) within RAND Infrastructure, Safety, and Environment (ISE), a unit of the RAND Corporation. The mission of RAND Infrastructure, Safety, and Environment is to improve the development, operation, use, and protection of society's essential man-made and natural assets and to enhance the related social assets of safety and security of individuals in transit and in their workplaces and community. The EEED research portfolio addresses environmental quality and regulation, energy resources and systems, water resources and systems, climate, natural hazards and disasters, and economic development both domestically and internationally. EEED research is conducted for government, foundations, and the private sector. Questions or comments about this report should be sent to the project leader, Mark Bernstein (mark_bernstein@rand.org). Information about the Environment, Energy, and Economic Development Program is available online (www.rand.org/ise/environ). Inquiries about EEED projects should be sent to the Program Director (ise_eeed@rand.org).

Table of Contents

Figures

Tables

Summary

The Department of Energy (DoE) Office of Energy Efficiency and Renewable Energy (EERE) has a portfolio of energy efficiency research and development programs that is intended to spur development of energy-efficient technologies. The goal of these programs is to decrease costs and improve efficiency of emerging technologies and increase the potential for consumers and businesses to adopt them. EERE, under requirements of the Government Performance Results Act (GPRA), must estimate the benefits of their portfolio of energy efficiency programs. With these estimates of benefits, EERE can then assess the cost-effectiveness of its programs and use this information in allocating its budget.

Currently, EERE estimates the benefits of its programs by analyzing their effects using the DoE's National Energy Modeling System (NEMS), a complex model of the U.S. energy system. Because the projected benefits of their programs depend heavily on the NEMS model, EERE is interested to know if certain assumptions in the NEMS model might impact the projected benefits. Specifically, the NEMS model uses data and parameters aggregated to the regional and national levels. If, for instance, the data or parameters used in the analysis actually vary considerably within a region, then NEMS will project biased results and using more disaggregated data—possibly at the state or utility level—could improve accuracy of the results. In this study, we examine how trends in several measures of the energy market may vary at the state and regional levels and in particular how one important parameter used in the NEMS model, price elasticity of demand (a measure of how demand responds to price), varies at the national, regional, state, and utility levels. With this initial examination, we offer some recommendations on whether EERE can improve their benefit estimates by using more disaggregated data in analysis of their programs.

Economic theory says that as energy prices rise, the quantity of energy demanded will fall, holding all other factors constant. Price elasticities are typically in the negative range, which indicates that demand falls as prices increase or, conversely, that demand increases as prices fall.

To determine if regional, state, or sub-state characteristics could affect the size of the impact from energy-efficiency technologies on energy prices, supply, and consumption, we looked at how individual factors—such as climate, supply constraints, energy costs, and demand for natural gas—might themselves affect the extent of the impact of energy efficiency.

Are There Regional Differences in the Price-Demand Relationship?

The object of this study is to determine whether the relationship between prices and demand differs at the regional, state, or sub-state level. In this study, we were interested solely in determining whether there are geographic differences in the price-demand relationship. We did not seek to understand how demand might impact prices and vice-versa, although some of our findings provide some insights into these issues. Our focus was on finding out whether the state- and regional-level differences were significant enough to recommend to the DOE that it should explore disaggregating its data by state or region when estimating the potential benefits of energy efficiency.

We examined three energy-demand components—electricity use in the residential sector, natural gas use in the residential sector, and electricity use in the commercial sector—at three or four levels of disaggregation of the data, depending on the availability of data. For each sector, we looked at national, regional, and state-level results. We also examined residential electricity use at the electric-utility level.

Our analysis indicates that there are regional and state differences in the price-demand relationship for electricity and natural gas. We did find, though, that there tends to be some consistency in residential electricity use among states within a region and visible differences between regions in demand and price trends, particularly for residential electricity use and less so for commercial electricity use or residential natural gas use. What this implies, for estimating the impact of energy-efficiency technologies, is that the DOE may have reason to explore differentiating the impacts of energy efficiency by region, at least for residential electricity. There does not seem to be a need, at least in the short run, for further disaggregation by geographic area, although more research is needed to offer a more conclusive recommendation.

We also found that the relationship between demand and price is small. That is, demand is relatively *inelastic* to price. We also found that in the past 20 years, this relationship has not changed significantly; analyses performed in the 1980s[1] showed approximately the same results. These findings might imply that there are few options available to the consumer in response to changes in the price of energy, and that price does not respond much to changes in demand. On the other hand, because prices were declining in real terms over most of the period we studied, the inelasticity of demand may be more of an artifact of the lack of price increases.

However, we now may be witnessing some changes in this area. The past few years have seen some increases in energy prices, with some states facing increasing electricity prices and all states facing increasing natural gas prices. While it is difficult statistically to uncover specific changes in trends, there are signs that demand growth has slowed, possibly due to a combination of increasing or flat prices and the economic slowdown of the past few years. Although we cannot say specifically that the relationship between price and demand might shift in an increasing-price environment, more analysis of recent trends may be warranted.

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[1] Bohi, Douglas R., and Mary Beth Zimmerman, "An Update on Econometric Studies of Energy Demand Behavior," *Annual Review of Energy*, Vol. 9, 1984, pp. 105–154; Dahl, Carol A., "Do Gasoline Demand Elasticities Vary?" *Land Economics*, Vol. 58, No. 3, August 1982, pp. 373–382; and Dahl, Carol A. and Thomas Sterner, "Analyzing Gasoline Demand Elasticities: A Survey," *Energy Economics*, July 1991, pp. 203–210.

Acknowledgments

We would like to thank Doug Arent of the National Renewable Energy Laboratory for his efforts to fund this study and help guide the development of the analysis. Special thanks to Brian Unruh from the Department of Energy and David Loughran of RAND for their insightful reviews of the analysis and helping us focus the paper. We also appreciate conversations we had with Dan Relles on understanding some of the data issues. We appreciate assistance provided to us by staff at the Energy Information Administration, and finally thanks to Nancy DelFavero for assistance in editing.

Chapter 1: Introduction

The Department of Energy (DoE) Office of Energy Efficiency and Renewable Energy (EERE) has a portfolio of energy efficiency research and development programs that are intended to spur development of energy-efficient technologies. The goal of these programs is to decrease costs and improve efficiency of emerging technologies and increase the potential for consumers and business to adopt them. EERE, under requirements of the Government Performance Results Act (GPRA), must estimate the benefits of their portfolio of energy efficiency programs. With these estimates of benefits, EERE can then assess the cost-effectiveness of its programs and use this information in allocating its budget.

Currently, EERE estimates the benefits of its programs by analyzing their effects using the DoE's National Energy Modeling System (NEMS), a complex model of the U.S. energy system. To make the estimates, DoE runs the NEMS model with traditional assumptions about the energy system and uses the results to establish baseline estimates of energy use and prices. DoE then introduces into the model the changes to the energy system attributable to EERE's R&D programs and estimates a new set of energy demands and prices. EERE uses the differences in the two projections as estimates of the impacts of its programs.

Because the projected benefits of their programs depend heavily on the NEMS model, EERE is interested to know if certain assumptions in the NEMS model might impact the projected benefits. Specifically, the NEMS model uses data and parameters aggregated to the regional and national levels. If, for instance, the data or parameters used in the analysis actually vary considerably within a region, then NEMS estimates of the impacts of energy efficiency might be misstated. Using more disaggregated data—possibly at the state or utility level—could then improve accuracy of the results. In this study, we examine how trends in several measures of the energy market may vary at the state and regional levels and in particular how one important parameter used in the NEMS model, price elasticity of demand (a measure of how demand responds to price), varies at the national, regional, state, and utility levels. With this initial examination, we offer some recommendations on whether EERE can improve their benefit estimates by using more disaggregated data in analysis of their programs.

Geographic Variability in Energy Markets Could Affect DOE Benefit Estimates

Geographical variation in price-demand relationship and price elasticity has important implications for the benefit estimates of EERE's programs. The NEMS model represents energy demand and supply at the regional level and uses one price elasticity for all regions. If energy markets vary substantially at the sub-regional level or if price elasticities vary across the country, then estimates of the impacts of energy efficiency technologies will vary by region and this will not be reflected I the NEMS runs.

Economic theory says that as energy prices rise, the quantity of energy demanded will fall, holding all other factors constant. Economic theory also suggests that consumers' demand for energy is less sensitive to price changes than the demand for many other commodities. Economists define consumers' sensitivity to price changes as a measure of *price elasticity.* Price elasticity is calculated as follows:

$$\text{Price Elasticity} = \frac{\%\Delta QuantityDemanded}{\%\Delta \Pr ice}$$

In this equation, the numerator and denominator are expressed as a percentage of change. Because price elasticity is a ratio of two percentages, it is not expressed as a specific unit of measure and can be compared across different commodities.

Price elasticities are typically in the negative range, which indicates that demand falls as prices increase or, conversely, that demand increases as prices fall. Demand elasticities are of two types, *inelastic* and *elastic,* and the range of each type differs. The range of inelastic demand is within absolute values of 0 to 1, and the elastic range begins with values greater than 1. These terms can be interpreted intuitively. A commodity with inelastic demand has a less than proportional change in demand for a given change in the price for the commodity. For instance, if prices increase by 10 percent on a good with a price elasticity of –0.20, then demand for the good drops by only 2 percent. In the elastic range, consumer demand responds with a greater-than-proportional change for a given price change. For instance, a good with an elasticity of −1.5 would have a 15 percent drop in demand with a 10 percent increase in price. This relationship is pictured in Figure 1.1.

The figure shows a conventional supply curve (S_1) and two demand curves with different elasticities (D_1 and D'_1). D_1 is less elastic (i.e. steeper) than D'_1. At equilibrium, both demand curves intersect the supply curve at the same point, with price at P1 and quantity at Q_1.

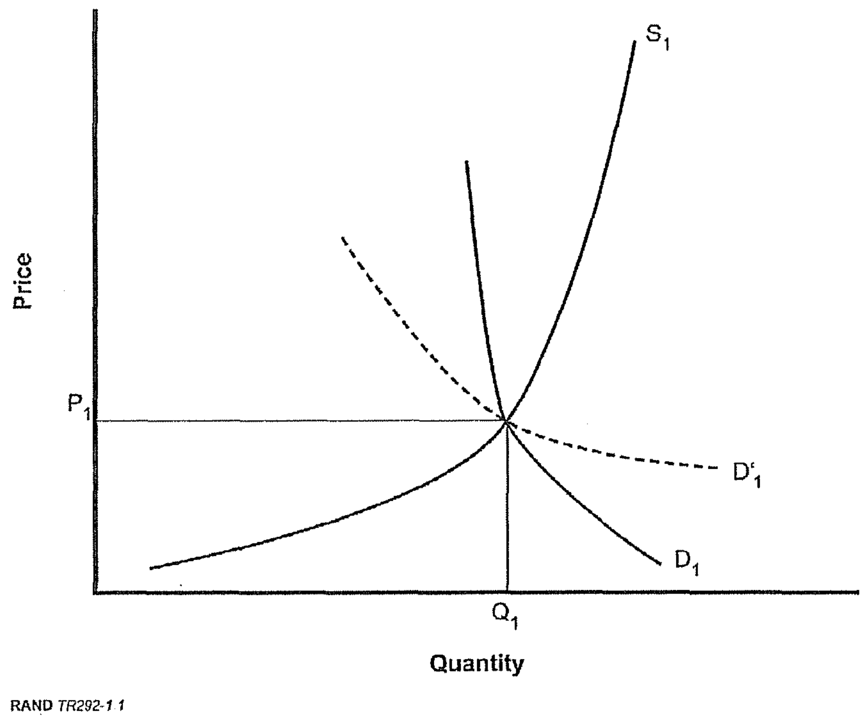

Figure 1.1: Relationship of supply and demand with two different demand curves

If the supply curve shifts inward, which could represent an increase in the price of a fuel used to produce electricity such as natural gas, the new equilibrium point would depend on which demand curve is used as demonstrated in Figure 1.2. If the demand curve is relatively inelastic (D_1) then prices would rise and there would be only a small reduction in demand (P_2, Q2). With the more elastic demand curve (D'_1), both the equilibrium price and the quantity are lower than the more inelastic curve (P'$_2$,Q'$_2$). In the end, the difference in the equilibriums would depend on the magnitude in the variation between the elasticities.

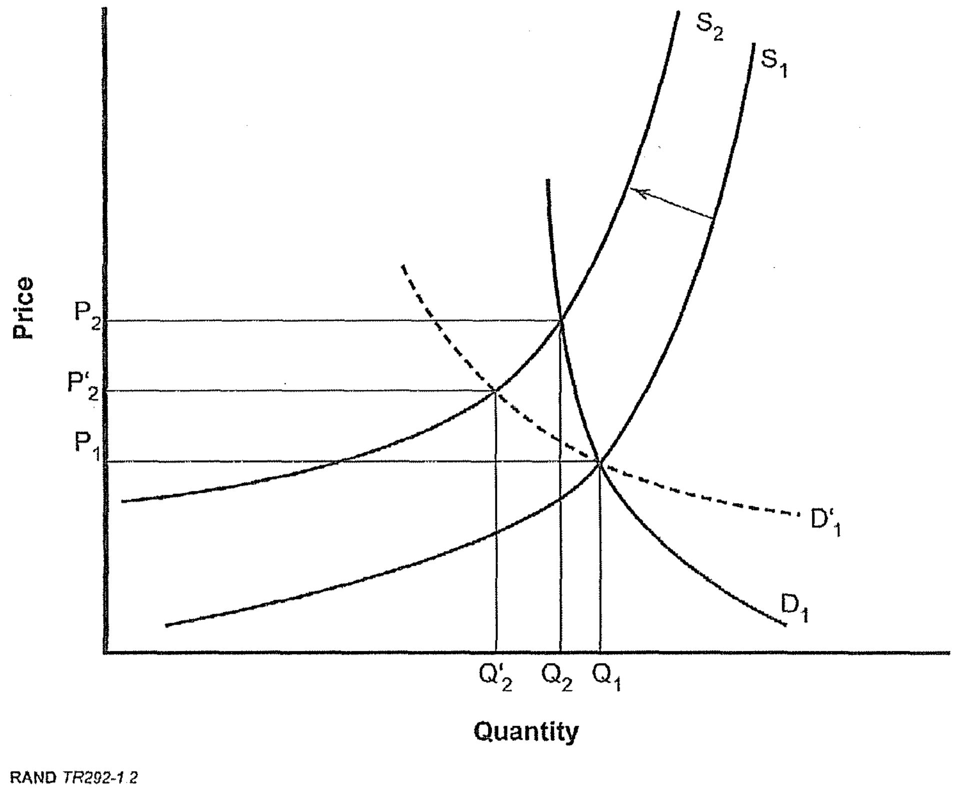

Figure 1.2: Impact of a shift in the supply curve

The price elasticity will also impact results if changes in demand are expected. In figure 1.3 we show the impact on price and quantity of a shift in the demand curve. In this case let's say demand increases – so the curve shifts outward from D_1 to D_2. If the supply does not change, with a less elastic demand curve the prices and quantity would be higher (P_2, Q_2) than if the demand curve was elastic (P'_2, Q'_2). Since energy efficiency impacts demand first, this picture is very relevant for EERE analysis. The impacts on price and quantity of changes in demand will certainly be different with different elasticities.

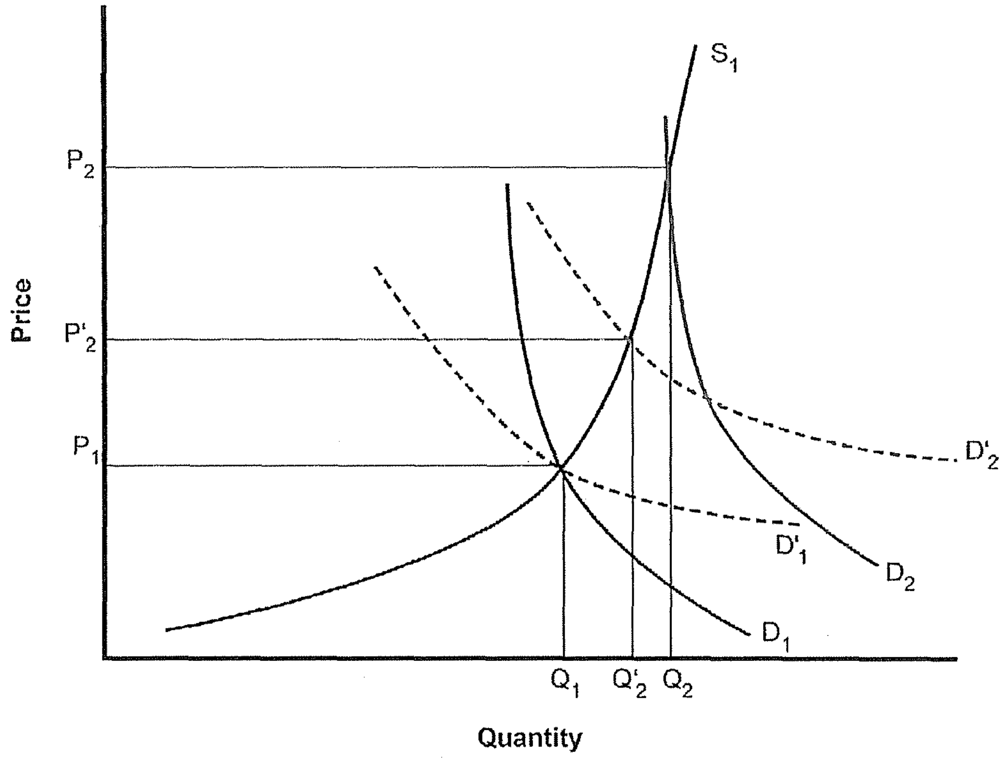

Figure 1.3: Impact of a shift in the demand curve

Price elasticities can be used to interpret how consumer demand responds to price changes. They also indicate how readily consumers can purchase substitutes for a product that has gone up in price and how much consumers value a particular good. Price elasticities can be used in this way because of the underlying theory of consumer response to price changes. A consumer with a fixed budget in the short term has three possible responses to a price change: (1) The consumer can buy another good as a substitute; (2) the consumer can buy less of the good with no corresponding purchase of a substitute; or (3) the consumer can continue to purchase the same amount of the good and reduce expenditures on other goods in his or her consumer bundle.

In the case of electricity and natural gas (the focus of this study), these commodities have a limited degree of substitutability, especially in the short term. For end uses such as home heating and cooking, consumers can switch between energy-using systems that use electricity or natural gas. However, the consumer may want to purchase a new appliance that uses the less-expensive energy source. In other uses, such as a power supply for a computer, electricity has no substitutes. Nevertheless, the consumer still has the option to purchase a more efficient computer and enjoy the same level of service using less electricity. Typically, purchasing a more efficient appliance or one that uses a different type of fuel requires replacing a relatively expensive item, like a computer or refrigerator, and is considered a long-run adjustment by the consumer to high energy prices.

Based on this analysis, consumer demand for electricity and natural gas should be relatively unresponsive to price changes in the short term and more responsive to price changes in the long term but could differ substantially by region. Demand for these goods is generally inelastic in the short term, because a consumer's main options when energy prices change are to vary how he or she uses energy-consuming appliances (e.g., adjust a thermostat or turn on fewer lights) or reduce expenditures on other goods. Over the longer term, consumers can buy appliances that use a different energy source and/or purchase more-efficient appliances. Therefore, price elasticities tend more toward the elastic range than the inelastic range in the long term.

One of the important benefit measures for the EERE programs is the projected energy savings from the energy efficiency programs. The diagrams above show that estimating the impacts on demand depends on the price elasticities used in the analysis. Therefore, if elasticities differ between regions, the model needs to include geographical variation in price elasticities to make accurate estimates. The following sections will discuss possible reasons for geographic variation in price elasticities and the relationship between energy efficient technologies and price elasticity.

Relationship Between Energy Efficiency and Price Elasticity

Energy-efficient technologies provide a substitute for energy consumption when energy prices increase, which has important implications for the price elasticity of demand in energy markets. The price-elasticity of demand measures the percentage change in the amount demanded given a percentage change in the price of a good. Overall, this measure reflects the value of a good to consumers and the availability of substitutes.

For the goods considered in this study, electricity and natural gas, the availability and cost of substitutes vary throughout the country. Constraints in infrastructure cause some of the differences in availability. For instance, the states of Maine and Florida have limited capacity for natural gas. Therefore, natural gas is a more costly substitute for electricity in these states relative to most others. In some cases, policy can drive differences in the cost of substitutes. Many states have programs to subsidize adoption of energy-efficient technologies, which also creates geographic differences in the cost of a substitute to electricity and natural gas. Both cases may cause price elasticities to vary across the country.

The preceding discussion provided reasons why the price elasticity of demand may vary and it suggests the direction that price elasticities could change. In areas where the costs of substitutes are competitive, price elasticities may increase in absolute magnitude (become more elastic) because consumers could more easily switch to substitutes as prices increase. Locations where particular energy uses are very valuable, such as air conditioning in southern states or winter heating in northern states, could have price elasticities smaller in absolute magnitude (more inelastic) because air conditioning and heating are so valuable during periods of extreme climate that consumers are unwilling to change their use when prices change. Again, both of these driving factors, the cost of substitutes and value of energy uses, vary geographically, which suggests price elasticity may differ across the country.

Analytical Approach

In this study, we analyzed energy demand for three markets—residential electricity, commercial electricity, and residential natural gas—and geographical variation in energy markets by region, state, and utility (for residential electricity). We assessed how trends in energy intensity, per capita energy expenditures, and expenditures as a share of income varied across the country. And, since the NEMS model currently uses one national value for price elasticity and the preceding discussion suggested some reasons why price elasticity might differ geographically, a primary focus of the study was to analyze if price elasticities vary at the regional, state, and utility levels. These analyses will help EERE evaluate whether they need to use more disaggregated analysis in estimating the benefits of their programs.

Summary of Findings

Our analysis indicates that there are significant regional and state differences in the price-demand relationship for residential electricity and less so for commercial electricity and for residential natural gas. We did find, though, that there tends to be some consistency among states within a region and visible differences between regions in consumption and price trends. This tendency seems to be particularly strong for residential electricity use. It is possible that this relationship is more significant for residential electricity because some electricity uses in the home may be more discretionary than commercial or natural gas uses. Some electric using appliances can be used less, lights can be switched off and more efficient bulbs used. Most commercial business has limited availability to alter electricity sue in the short run, and residential natural gas use which is primarily for water heating, cooking and heating has less potential for modifications.

The results imply that the DOE may have reason to explore differentiating the impacts of energy efficiency by region, at least for residential electricity. There does not seem to be a need, at least in the short run, for further disaggregation by geographic area in the two other energy markets, although more research is needed to offer a more conclusive recommendation.

We also found that the relationship between consumption and price is small. That is, demand is relatively *inelastic* to price. We also found that in the past 20 years, this relationship has not changed significantly; analyses performed in the 1980s[2] showed approximately the same results. These findings might imply that there are few options available to the consumer in response to changes in the price of energy, and that price does not respond much to changes in demand. On the other hand, because prices were

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[2] Bohi, Douglas R., and Mary Beth Zimmerman, "An Update on Econometric Studies of Energy Demand Behavior," *Annual Review of Energy*, Vol. 9, 1984, pp. 105-154; Dahl, Carol A., "Do Gasoline Demand Elasticities Vary?" *Land Economics*, Vol. 58, No. 3, August 1982, pp. 373-382; and Dahl, Carol A. and Thomas Sterner, "Analyzing Gasoline Demand Elasticities: A Survey," *Energy Economics*, July 1991, pp. 203-210.

declining in real terms over most of the period we studied, the inelasticity of demand may be more of an artifact of the lack of price increases.

However, we now may be witnessing some changes in this area. In the past few years, energy prices have increased with some states facing increasing electricity prices and all states facing increasing natural gas prices. While it is difficult statistically to uncover specific changes in trends, there are signs that demand growth has slowed, possibly due to a combination of increasing or flat prices and the economic slowdown of the past few years. Although we cannot say specifically that the relationship between price and demand might shift in an increasing-price environment, more analysis on recent trends may be warranted.

Organization of This Report

In Chapter Two, we provide a brief overview of 30 years of literature on the energy price-demand relationship and past attempts to estimate price elasticity. We then follow with an explanation of the methodology we used in this study. Chapters Three through Six present the study results in order by increasing levels of disaggregation of data—national-level analysis in Chapter Three, regional-level analysis in Chapter Four, state-level analysis in Chapter Five, and utility-level analysis for the residential electricity sector in Chapter Six, Chapter Seven presents the conclusions derived from the results of the study, implications for the DOE and for federal energy-efficiency policy, and thoughts for next steps on research topics. The appendixes present methodological details and our data sources.

Chapter 2: Economic Theory, Literature, and Methodological Approach

In this chapter, we present information that we used in producing our findings on energy price-demand relationships and the comparative impacts from energy efficiency at the national, regional, state, and utility levels. We first provide an overview of some of the literature on energy demand, and then describe the model we used to estimate energy demand.

Previous Literature on Energy Demand

Previous studies have found that energy demand is inelastic in the short run but more elastic in the long run. Several studies also found that price elasticities varied across locations, but the same general pattern remained (inelastic demand in the short run and more-elastic demand in the long run). The energy-demand literature consists of several dozen papers and is too voluminous to describe here in detail. Therefore, this section focuses on a representative handful of survey articles on this subject.

Taylor (1975) completed one of the first literature surveys on electricity demand. He reviewed the existing studies on residential, commercial, and industrial electricity demand. For residential electricity, he reported that short-run price elasticities varied from –0.90 to –0.13. Long-run price elasticities ranged from –2.00 to near zero. The only study of commercial price elasticities that differentiated between long-run and short-run elasticities observed a short-run price elasticity of –0.17 and a long run elasticity of –1.36.

Bohi and Zimmerman (1984) conducted another comprehensive review of studies on energy demand. They surveyed the existing research on demand in the residential, commercial, and industrial sectors for electricity, natural gas, and fuel oil. They also reviewed studies on gasoline demand. Bohi and Zimmerman found that the consensus estimates for residential electricity price elasticities was –0.2 in the short run and –0.7 in the long run. They reported that the range of estimates in commercial electricity was too variable to make conclusions about consensus values. For residential natural gas consumption, they reported consensus values of –0.2 in the short run and –0.3 in the long run.

Bohi and Zimmerman also concluded that the energy price shocks of the 1970s did not change the structural characteristics of consumer demand. The studies they reviewed include studies from before and after the energy-price shocks in 1974 and 1979. They compared studies from the pre– and post–price-shock periods and also reported findings from studies that had divided study samples across the various periods to determine if any structural changes occurred in energy demand. One hypothesis they tested is that demand may become more elastic at higher price levels. Another hypothesis they tested is that rapid price changes sensitize consumers to energy demand, causing consumers to change their habits to conserve more energy.

Bohi and Zimmerman did not find much evidence to support their hypotheses. The estimated price elasticities from studies before and after the price shocks of the 1970s do not differ substantially. However, the authors could not use statistical tests of significance to evaluate the differences between price elasticities. In addition, several studies reviewed by Bohi and Zimmerman tested whether the price shocks changed the structural characteristics of the energy demand equation used to estimate elasticities. They found that energy demand decreased significantly after the price shocks. But, their analyses did not reveal any change to the structural characteristics of the energy demand equation.

Dahl and Sterner (1991) conducted a comprehensive review of the literature on gasoline demand (gasoline demand was not included in our study due to lack of available data). However, their review found consensus estimates on price elasticities. Dahl and Sterner concluded that the average short-run price elasticity was –0.24, and the average long-run price elasticity was –0.80.

Several previous studies also examined whether energy-price elasticity varied across locations. Houthakker et al. (1974) estimated price elasticities for residential electricity and gasoline and found that elasticities varied across states. They also found some correlation between price elasticity and degree of urbanization. Elasticities generally became more elastic as the degree of urbanism decreases, except for the most-rural states, which had a positive elasticity for both gasoline and residential electricity demand. Houthakker et al. did not offer an explanation for this pattern, especially the positive elasticity for the most-rural states.

Maddala et al. (1997) estimated price elasticities in 49 U.S. states (excluding Hawaii) and found variation across states. The mean of the estimates was –0.16. The minimum was –0.28, and the maximum was –0.06. In the long run, the mean was –0.24, with a minimum of –0.87 and a maximum of 0.24.

Garcia-Cerrutti (2000) estimated price elasticities for residential electricity and natural gas demand at the county level in California. For residential electricity, the estimate of the mean was –0.17, with a minimum of –0.79 and a maximum of 0.01.

In summary, previous studies show that price elasticities are generally inelastic in the short run and more elastic in the long run. Further, elasticities vary at the state and county levels; however, the same general pattern of inelastic demand in the short run and more elastic demand in the long run still holds.

Estimation Approach

For this study, we used a dynamic demand model developed by Houthakker et al. (1974). This model estimates long-run and short-run energy demand by using lagged values of the dependent variable along with current and lagged values of energy prices, population, economic growth/per capita income, and climate variation. The model estimates short-run demand using energy prices and quantity demanded in the current period, and it estimates long-run demand through changes in the stock of energy-consuming appliances reflected by the lagged dependent variable. The technical details of the model and the process for making adjustments to reflect long-term demand are described in Appendix A.

We used state-level panel data on residential and commercial electricity consumption and residential natural gas consumption in the 48 contiguous U.S. states. The residential electricity and natural-gas data span 1977 through 2004. The commercial electricity data include only the years 1977 through 1999 because of limitations in economic data available from the Bureau of Economic Analysis. We also used a dataset on residential electricity consumption at the utility level from 1989 through 1999. The state energy data are from the DOE Energy Information Administration's (EIA) *Electric Power Annual* (see Appendix B for details). This publication contains data on electricity consumption and prices by energy-using sector. The natural gas data are from a "U.S. Gas Prices" table on the EIA's Natural Gas Navigator Web site.[3] Finally, the utility data set comes from data reported to the DOE on form EIA-861. Submission of this form is a mandatory reporting requirement for utilities in the United States. The data on demographic and economic variables are from the Bureau of Economic Analysis in the Department of Commerce (again, see Appendix B for details).

The analysis uses a fixed-effects model, which controls for time effects, and a set of covariates. The location-specific price elasticity estimates come from interaction terms in the model between a location-indicator variable (region, state, or utility) and the variable of interest (price or lagged quantity). The estimates on the interaction terms indicate any differences between locations in the sample. The final elasticity estimates for each state are the sum of the estimate of the main effect and the interaction term for the location. The analysis uses hypothesis tests to determine if individual estimates are significantly different from zero and if a location is significantly different from the other locations.

We estimate this model using the following fixed-effect specification:

$$Q^{D}_{i,t} = Q^{D}_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

[3] Current data on the Web site can be found at table can be found at http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

where $Q^D{}_{i,t}$ is log energy demand in state i and year t, $Q^D{}_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g., energy prices, population, income, or climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The residual has three components:

- s_i is an indicator variable that captures time-invariant differences in energy demand across states ("state fixed effects").
- y_t is an indicator variable that captures time effects common to all states ("year fixed effects").
- $\varepsilon_{i,t}$ is a random error term.

We estimate any spatial differences in the energy demand relationship by adding interaction terms between the region or state indicator variables and the regressors of interest (price, quantity, and income). These interaction terms allow the estimated parameters to vary for each region or state, and we can then determine whether price elasticities differ across geographical units.

The fixed-effects model controls for state-specific time-invariant factors that could bias the parameter estimates. The year effects in the model control for any time effects common to all states in a particular year, which could bias the parameter estimates. These effects control for many potential sources of bias. However, the fixed and year effects do not control for state-specific factors that vary through time. If any of these factors are correlated with explanatory variables and also affect energy demand, then the regression will have biased estimates.

The fixed-effects model controls for effects specific to each state or utility that do not vary through time. An example of such a fixed effect is abundant energy supplies in certain states, such as hydroelectric power in the Pacific Northwest states or coal in West Virginia. This is a fixed effect because the states have those resources due to geographical factors that cannot change in the sample period. These states also tend to have much lower energy prices than other states. The fixed-effects model controls for this particular state-specific effect that does not vary through time and all other fixed effects that may or may not be measurable. Without controlling for these effects, the effects would bias the results. Appendix A explains the fixed-effects model in more detail.

The model also controls for time trends that affect all the states uniformly. An example of a time trend would be the enactment of a new energy-related law or a change in the majority political party in Congress. These factors have a constant, national effect, for which the model can control using indicator variables for each year.

The next four chapters present an overview of the results of our analysis of how energy prices and demand interact for residential electricity and natural gas and for commercial electricity. Details of all the results are presented in Appendix D. Because the purpose of this study is to see whether the price-demand relationship differs at the regional or state level, we present the results in descending order of dissaggregation—national, then regional, then state, and finally utility-level results. Within the chapters, we first discuss residential electricity, then commercial electricity, and then residential natural gas.

Chapter 3: National-Level Results

Residential Electricity Use

Real electricity prices peaked in the early 1980s in the United States and steadily declined until 2000–2001 (see Figure 3.1). In 2001, average electricity prices increased in many states, and the figure shows a slight price rise over the past two years in the period studied. The figure also shows that residential electricity demand rose steadily during this period, although it appears that demand growth may have slowed after 2002. The long-term trend is an average annual increase in demand of approximately 2.6 percent.

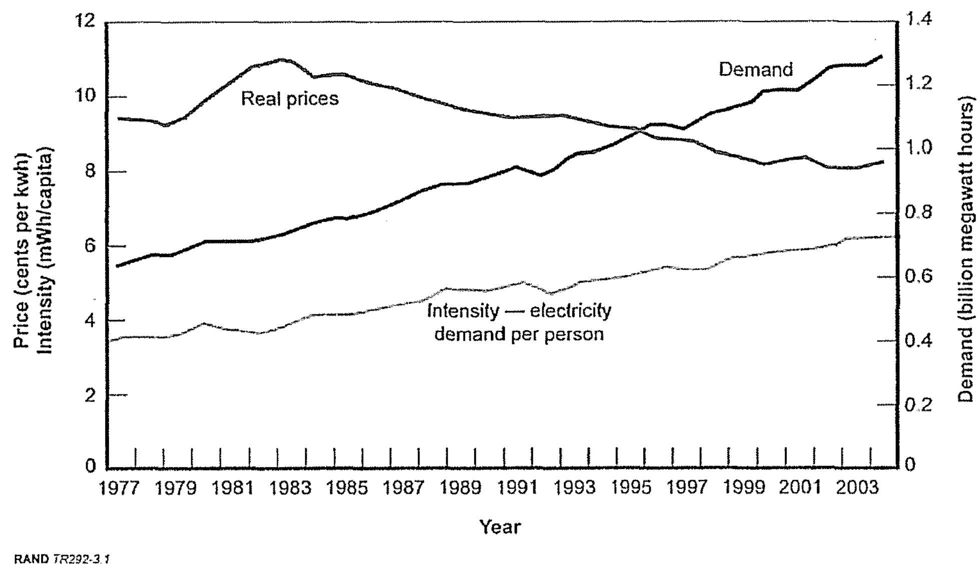

Figure 3.1: Residential Electricity Prices, Demand, and Intensity, 1977–2003

There also was a steady increase in *intensity* (i.e., per-capita residential electricity use) until 2002. The long-term trend in the time series is an average annual increase of 1.5 percent. Per-capita residential electricity seems to have leveled out over the past few years of the period, perhaps due to the flattening of prices and the post-9/11 recession.

To generate values of the price-demand relationship that we could compare across regions and states, we use the functional form described in Chapter Two for estimating the price elasticity for residential electricity. Table 3.1 displays the results of our regression analysis for the residential electricity sector. It presents the coefficients from the regression analysis and notes whether the variable is significant. The dependent variable is residential electricity demand. The data points represent each state for each year in the sample. The independent variables are electricity demand in the previous year; average real electricity price in the current and previous years; residential disposable income in the current and previous years; population in the current and previous year; natural gas price in the current and previous years; and climate measured as heating and cooling degree days (see Appendix A for a definition of *degree days*). Definitions of the variables are presented in more detail in Appendix C. Details of the regressions are in Appendix D.

These estimates reflect national-level values.

Table 3.1: Results of Regression Analysis of Residential Electricity Demand, 1977–2004

Variable	Coefficient	Statistically Significant
Electricity demand in previous year	.232	Yes
Electricity price in current year	-.243	Yes
Electricity price in previous year	-.129	Yes
Income in current year	.003	No
Income in previous year	.384	Yes
Population in current year	-.225	No
Population in previous year	.827	Yes
Natural gas price in current year	-.005	No
Natural gas price in previous year	.111	Yes
Climate – heating and cooling degree-days	.246	Yes

The table shows that the estimated short-run price elasticity is –0.2, which is statistically significant. The estimated long-run price elasticity is –0.32, and this value is also statistically significant. These estimates are consistent with results from the studies of residential electricity elasticity, cited in Chapter Two, which were conducted with data from earlier years. The survey literature concluded that the residential short-run elasticity was near 0.2.

The results also generally show that, except for price, the current-year variables are not significant, but the lagged or previous-year variables are statistically significant, suggesting that demand for electricity responds after changes occur in factors that influence the demand. For example, a consumer's level of income does not seem to impact demand in the same year, but income from one year seems to impact demand in the following year. This essentially means that change in income over time impacts electricity use, and growing incomes lead to increasing electricity use. Population growth has a similar effect. Natural gas prices have an expected result—increasing natural gas prices one year lead to increasing electricity demand in the following year. This pattern would reflect cases in which people switch from natural gas to electricity for some energy-consuming applications, such as heating or cooking. Finally, the more heating and cooling degree days there are, the higher the demand for electricity.

None of these results are unexpected, although what might be somewhat surprising is that the basic magnitude of these results has not changed in the past 20 to 30 years. Previous analyses done in the late 1980s and early 1990s showed just about the same results.

Commercial Electricity

We next examine the price-demand relationship for use of electricity by the commercial sector. Some commercial-sector electricity data exhibit trends similar those seen in the residential-sector data (see Figure 3.2). Real prices of electricity peaked in the early 1980s and steadily decreased through the period studied. Demand consistently increased throughout the study period. The average annual growth in demand during the period was 3.4 percent. Because the data we have for the commercial sector go only to the year 2000, we do not display recent price increases and do not know how they might have impacted demand.

In Figure 3.2, we show two pictures of commercial electricity intensity. One is electricity demand in mWh per dollar of commercial gross state product (GSP)—i.e., the size of the commercial electricity sector in economic terms. By this measure, electricity use has declined as a ratio of electricity demand to economic output from the commercial sector.

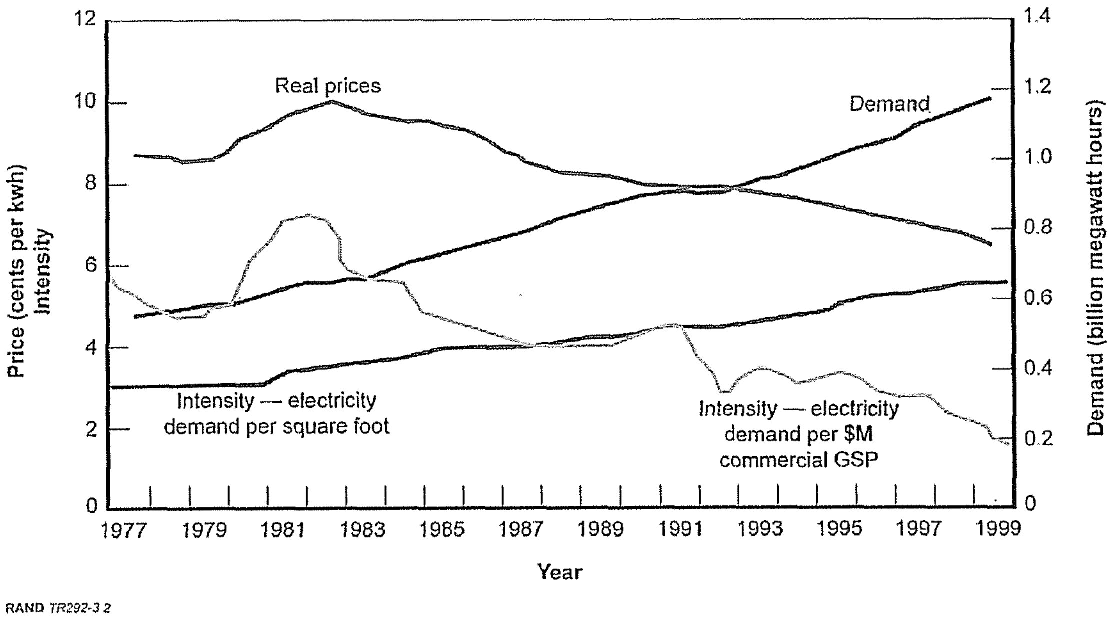

Figure 3.2: Commercial Electricity Prices, Demand, and Intensity, 1977–1999

The other measure of intensity is electricity use per available square feet of space in the commercial sector. By this measure, electric intensity has increased over the period, reflecting the rapid growth in demand. This trend implies that the commercial sector, while getting more productivity out of electricity on a per-dollar basis, is continuing to add electricity loads to buildings, despite the fact that significant amounts of new, and ostensibly more-efficient, commercial space was added over the last few years of the period illustrated in the figure.

The relationship among demand, price, and other factors in the commercial sector has some similarities to the relationship among demand, price, and other factors in the residential sector and also some significant differences. Table 3.2 displays the regression analysis results for a regression with the dependent variable being commercial electricity demand. The independent variables have a similar construct as the residential model—demand in the previous year; prices in the current and previous year; GSP for the commercial sector (i.e., income) in the current and previous year; office-space measures in square feet in the current and previous year; natural gas prices; and climate.

The commercial electricity regression estimates are also consistent with estimates cited in Chapter Two. The short-run price elasticity is –0.21, and the long-run price elasticity estimate is –0.97. Previous studies found short-run elasticities somewhere around –0.2. Long-run elasticities were more variable, and the survey literature did not report consensus values for long-run elasticities. Our long-run estimate of –0.97 is within the consensus range for residential electricity and natural-gas demand, however.

Table 3.2: Regression Analysis Results for Commercial Electricity Demand

Variable	Coefficient	Statistically Significant
Electricity demand in previous year	.785	Yes
Electricity price in current year	-.209	Yes
Electricity price in previous year	-.148	Yes
Commercial GSP in current year	.155	No
Commercial GSP in previous year	-.039	No
New floor space in current year	.504	No
New floor space in previous year	-.421	No
Natural gas price in current year	-.023	No
Natural gas price in previous year	.049	Yes
Climate – heating and cooling degree-days	.246	Yes

Interestingly, of the many of the factors that we thought should impact electricity demand in the commercial sector, commercial economic output (i.e., GSP) and floor space turned out to be not significant.

Natural Gas

The patterns for residential natural-gas demand differ from those in the electricity markets (see Figure 3.3). Prices peaked in the early 1980s and then again after 2001. Demand for natural gas in the short term is more variable than demand for electricity in the short term, and there is no real growth in demand over the period that was studied, and a recent downward trend perhaps reflects increased prices.

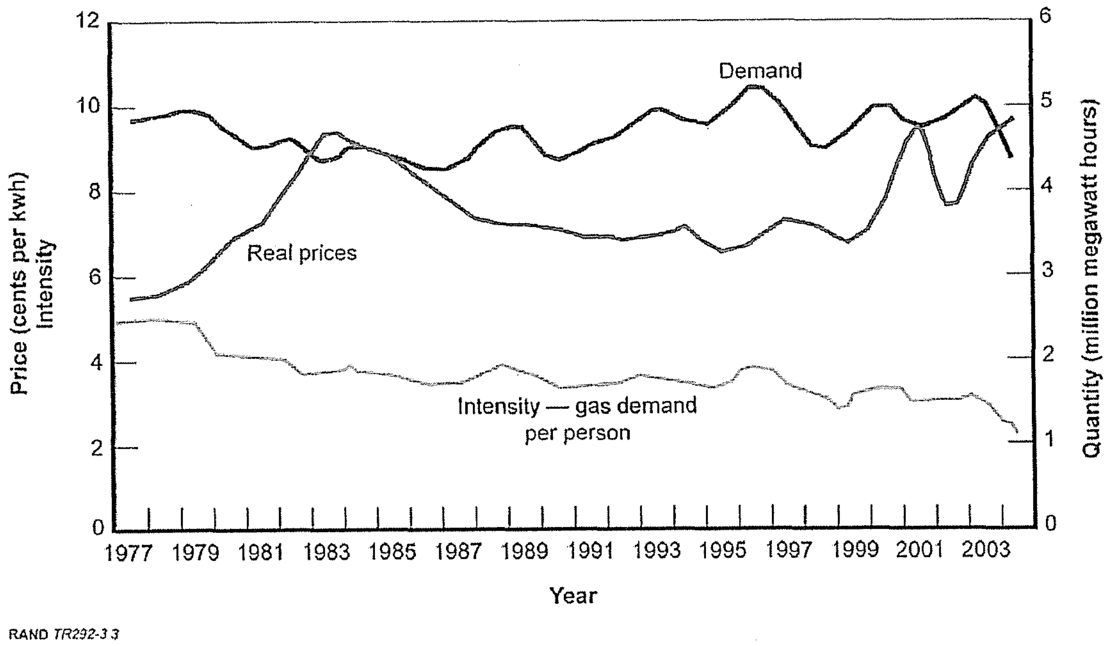

Figure 3.3: Residential Natural Gas Prices, Demand, and Intensity, 1977–2003

In contrast to residential electricity intensity, natural gas intensity declined during this period. The long-term trend during this period was a 0.9 percent decline in intensity (defined for this sector as demand per capita for natural gas), reflecting some improved energy efficiency and some substitutions away from natural gas.

The regression estimates also differ from those for the electricity market (see Table 3.2). Table 3.3 shows regression results, with the dependent variable being residential natural gas prices and the same variables as were used for the residential electricity regression. The short-term price elasticity is –0.12, and long-term price elasticity is –0.36. Bohi and Zimmerman (1984) reported consensus values of –0.2 in the short term and –0.3 in the long term. These values may reflect the fact that there are fewer opportunities for consumers to reduce their demand for natural gas in response to price, possibly because the use of natural gas in the home (i.e., for air and water heating and cooking) is a necessity, whereas turning off some lights or using fewer electric appliances is optional.

Table 3.3: Regression Analysis Results for Residential Natural Gas Demand

Variable	Coefficient	Statistically Significant
Natural gas demand in previous year	.67	Yes
Natural gas price in current year	-.12	Yes
Natural gas price in previous year	-.08	Yes
Electricity price in current year	.03	No
Electricity price in previous year	.11	Yes
Income in current year	.24	Yes
Income in previous year	.07	No
Population in current year	1.18	Yes
Population in previous year	-.86	Yes
Climate – heating and cooling degree-days	.27	Yes

The natural gas results differ from those for electricity. Income in the current year is a significant factor in demand for natural gas, whereas income in the previous year is not. The reason that previous-year income is significant for electricity could be because increased income might lead to consumers buying new appliances that add to the electrical load in the following year. In the case of natural gas, by comparison, there a that increased income might lead to consumers turning up the thermostat in the winter, adding to their current-year natural-gas consumption. The impact of electricity price on natural gas demand in the previous year is consistent with what we saw with the impact of natural gas price on electricity demand.

Summary of National-Level Results

As we have seen in this chapter, there are similarities and differences between the patterns of demand and price when comparing residential electricity, residential natural gas, and commercial electricity. Residential electricity use and intensity increased over the period we studied, although recent electricity price increases have slowed the growth of demand. Natural gas use has been flat, and intensity has declined, and we might see a greater decline due to recent natural-gas price increases. Commercial electricity use grew rapidly over the period studied, and while electricity as a share of output in the commercial sector has declined, electricity use per square foot of office space has continued to increase. A comparison of estimated price elasticities for the three sectors is presented in the Table 3.4.

Table 3.4: Price Elasticities for Residential Electricity, Commercial Electricity, and Residential Natural Gas at the National Level

	Residential Electricity	Commercial Electricity	Residential Natural Gas
Short-run elasticity	-.24	-.21	-.12
Long-run elasticity	-.32	-.97	-.36

Short-run price elasticities for electricity are similar for residential and commercial demand, although it appears that changes in commercial electricity price can have a bigger impact in the long term than in the short term. In the short run, natural gas demand is less elastic than demand for electricity but is about the same in the long run.

We used the national-level information presented in this chapter as a starting point for determining whether elasticities differ significantly among regions and states. The next chapter describes the regional-level results.

Chapter 4: Regional Results

This chapter describes the results from our analysis of trends in the three energy markets (residential electricity, commercial electricity, and residential natural gas) at the regional level. The analysis uses the nine census divisions that the DOE Energy Information Agency uses in energy modeling and forecasting: New England, Mid-Atlantic, South Atlantic, East North Central, East South Central, West North Central, West South Central, Mountain, and Pacific (see Figure 4.1).[4]

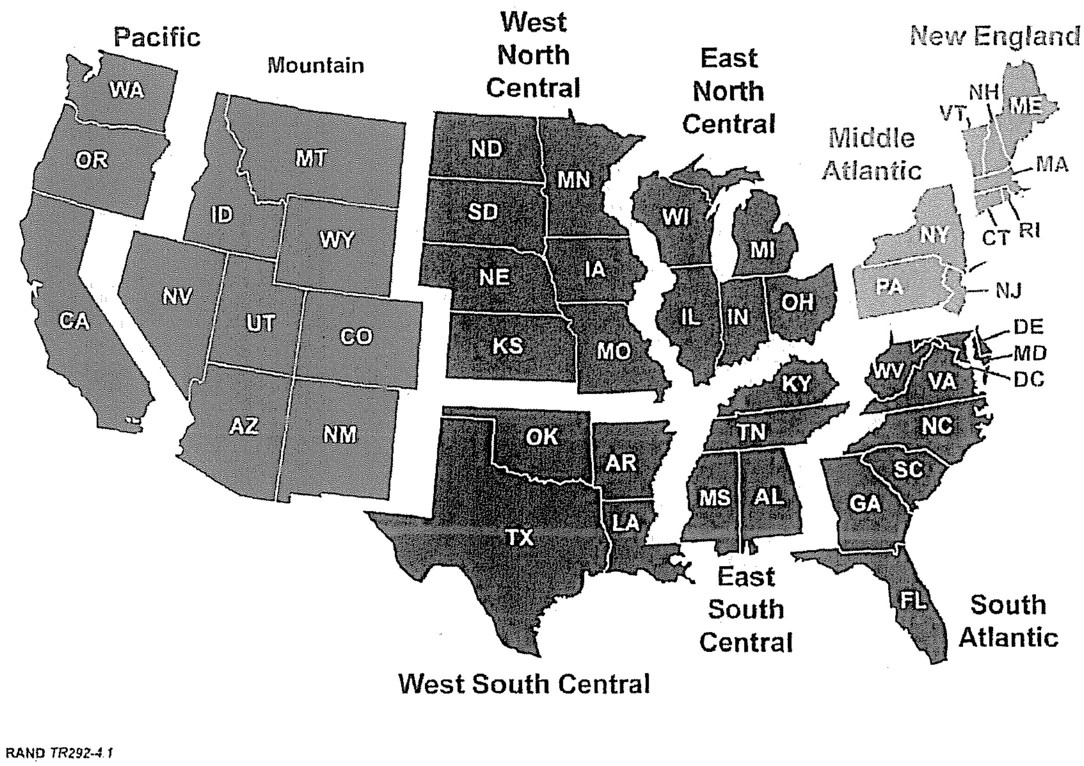

Figure 4.1: DOE Energy Information Agency Census Regions

In this analysis, we look at regional trends in energy intensity, energy expenditures, and expenditures as a share of income to determine if they differ among regions. We then

[4] We excluded Alaska and Hawaii from our analysis because they are unique in their energy uses and climate.

reproduce the regressions shown in the national-level analysis in Chapter Three to determine if there are significant differences in the price elasticities among regions.

Residential Electricity

Of the three markets that we examined in this study, residential electricity shows the most regional differentiation. Figures 4.2, 4.3, and 4.4 display trends in residential electricity use, expenditures, and expenditures as a share of total income, respectively, for the nine DOE census regions. The Figure 4.2 shows regional trends in per-capita residential electricity intensity.

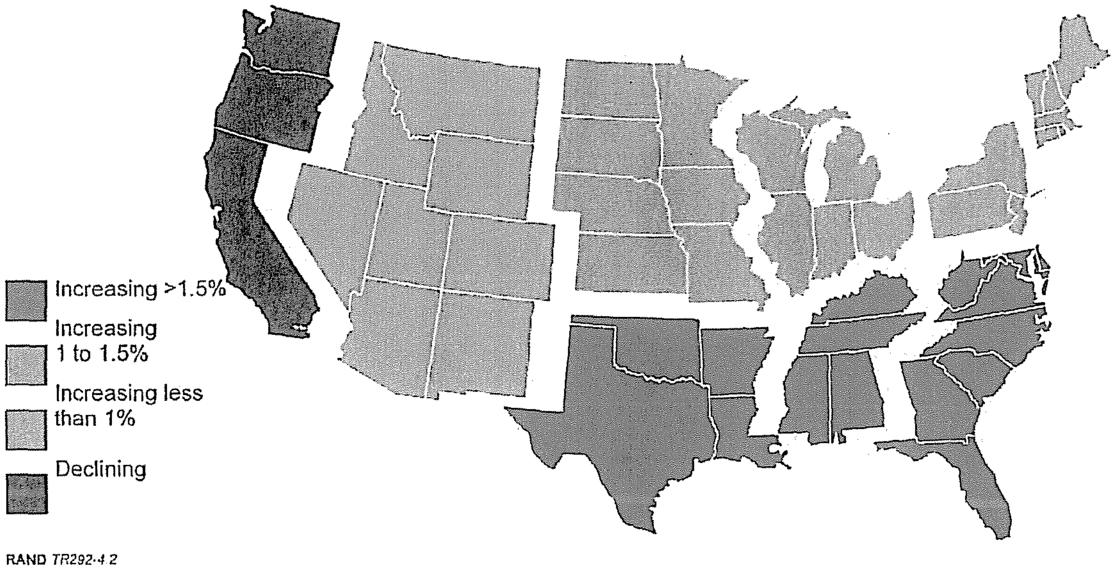

Figure 4.2: Regional Trends in Per-Capita Residential Electricity-Intensity, 1977–2004

Figure 4.2 shows four categories of trends in intensity–increasing over the period more than 1.5 percent on average, increasing between 1 percent and 1.5 percent per year on average, increasing less than 1 percent, or declining. Only one region had declining electricity intensity--the Pacific. Residential electricity intensity is growing fastest in the South Atlantic and East South Central regions. The Middle Atlantic, East North Central, and West North Central regions have the next-fastest growth rates. New England and the Mountain states have growth rates of less than 1 percent.

It is interesting to note that some commonality exists across contiguous regions. The East South Central, West South Central, and South Atlantic regions have experienced the most-rapid growth in electricity intensity, perhaps driven by air-conditioning loads and rapidly growing populations. The Middle Atlantic and West North Central regions also have had increasing air-conditioning loads at levels that did not exist until the late 1980s, and they have seen relatively rapid growth in electricity intensity over this period.

The Pacific Coast, which is dominated by California in its magnitude of electricity use, has had declining electricity intensity, possibly due to energy-related building codes that are the strictest in the nation and have been in place longer than any others.

All of these findings might imply that the impact of energy efficiency would be greater in areas such as the South in which the intensity of electricity use has been growing more rapidly than in other regions and might have less of an impact in the Pacific Coast where intensity has been declining.

Figure 4.3 shows growth trends for average expenditures on residential electricity. The figure shows that average expenditures on residential electricity are growing in all regions but provides a different picture than residential electricity intensity. Expenditures are growing most rapidly in the South Atlantic, East South Central, New England, and Pacific Coast regions. The Middle Atlantic and West South Central regions have the next-fastest growth rate, while the Mountain, East North Central, and West North Central regions have the slowest growth rates.

In a demand-price relationship, one might expect to see a picture similar to the one for electricity intensity--those areas with the most rapid increases in expenditures would have declining or slower growth in electricity intensity. While this is true for the Pacific states and Northeast, the opposite is true for the South Atlantic and East South Central regions. This is the first indication that the regional differences in the demand-price relationship might matter when estimating the impact of energy efficiency on other demand changes.

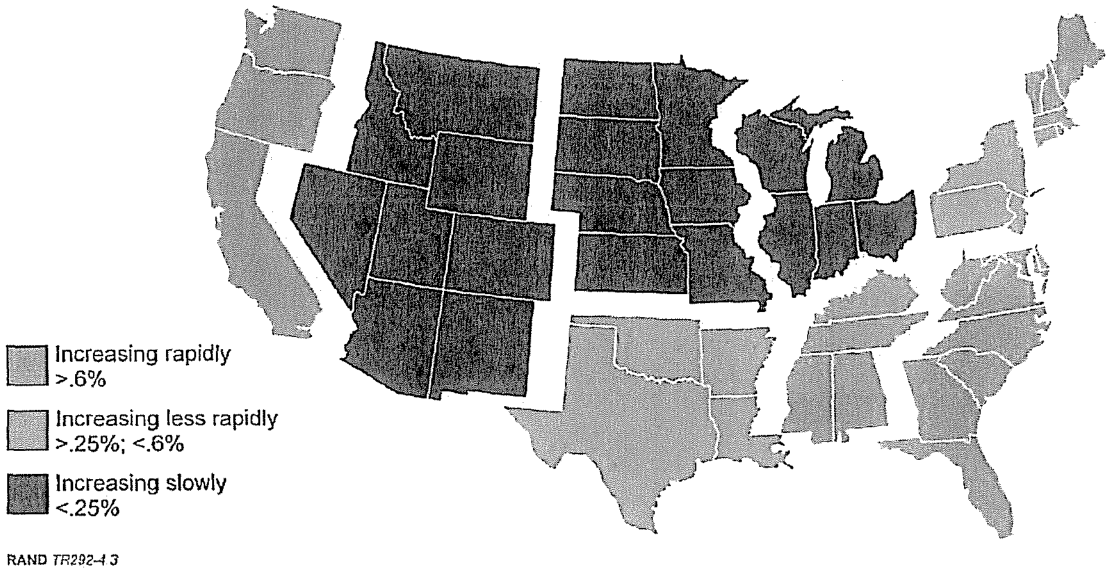

Figure 4.3: Regional Trends in Average Expenditures on Residential Electricity, 1977–2004

We now look at average expenditures on residential electricity as a share of personal income (see Figure 4.4). Although the spread of the numbers is small, there are a few interesting findings to note. First, even though expenditures on electricity have been rising, the share of electricity as a percentage of income has been declining, meaning that incomes are growing faster than electricity use. In the Mountain and Northeast regions, the relationship is what we would expect—where expenditures per dollar of income are declining rapidly, electricity intensity is growing quickly. We would expect that where the expenditures per dollar of income are declining more slowly than in other regions, electricity intensity growth would be slower or declining (as is the case in the Pacific Coast). But in the South Atlantic and East South Central regions, we find that even though the expenditure per dollar of income is not declining as fast as that in other regions, electricity intensity is growing more rapidly than in the other regions. This finding might be an indication that electricity use in the South Atlantic and East South Central regions is relatively insensitive to the cost of using electricity. At the very least, it is another indication of regional diversity. We also see some commonality among neighboring regions--for example, energy intensity in all the Southern regions is declining more slowly than in other regions, while in the mid-Northern regions it is declining more rapidly.

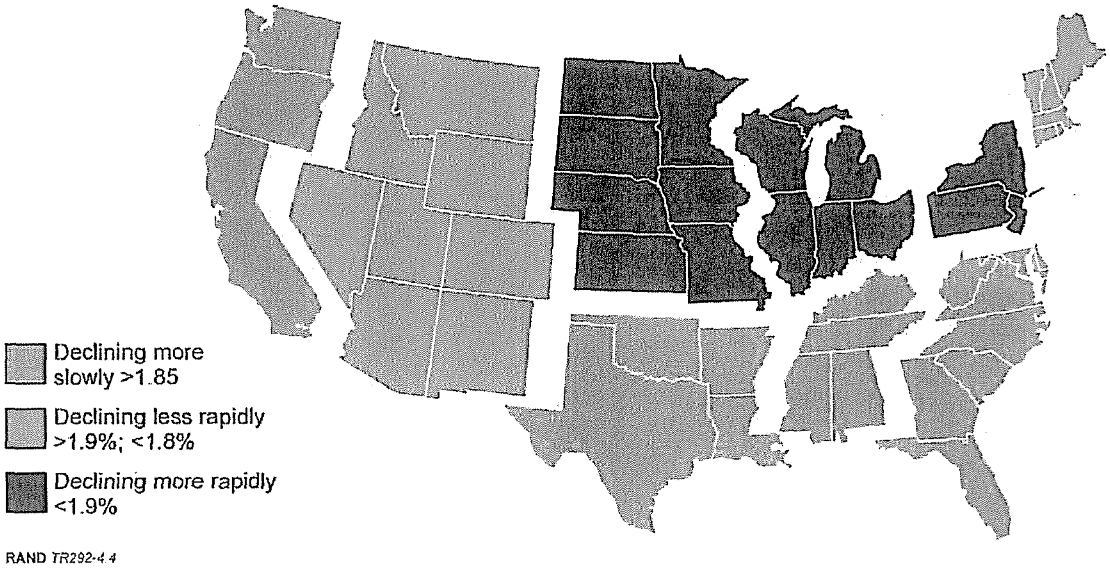

Figure 4.4: Regional Trends in Average Expenditures on Residential Electricity as a Share of Income, 1977–2004

One might conclude from Figures 4.2 through 4.4 that there are regional differences in the relationship between electricity demand and price and regional differences in the trends in electricity usage and expenditures. Using the method described in Chapter Two, we estimated the short-run and long-run price elasticities by region, which are presented in Figures 4.5 and 4.6. We find that the regional estimates of short-run elasticities range from -.04 in the East North Central region to .31 in the South Atlantic region. We also present the 95 percent confidence interval for each of the regional estimates. Where the confidence intervals do not overlap, we can say the regions are significantly different from each other. Where they do overlap, there may be differences, but, statistically, it is difficult for us to determine if they are actually distinct. In this case, all the confidence intervals overlap to some extent, except for those for the South Atlantic and East North Central estimates. Those two regions are the only ones that have significant differences in elasticities.

Long-run demand (see Figure 4.6) is more elastic than short-run demand in each region, and while the long-run pattern is relatively similar to the short-run pattern, the East South Central region in this case is the most elastic, and the differences between the East South

Central and South Atlantic regions and the East North Central region are statistically significant. The other regions differ from one another less for long-run elasticities than they do for short-run elasticities.

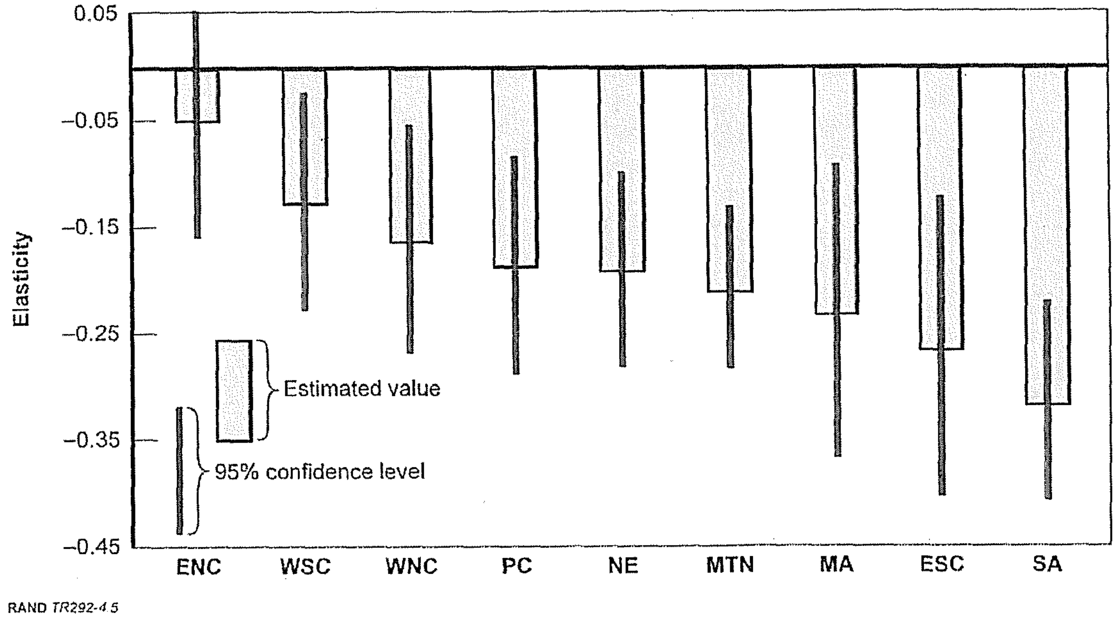

Figure 4.5: Estimated Short-Run Residential-Electricity Price Elasticities by Region, 1977–2004

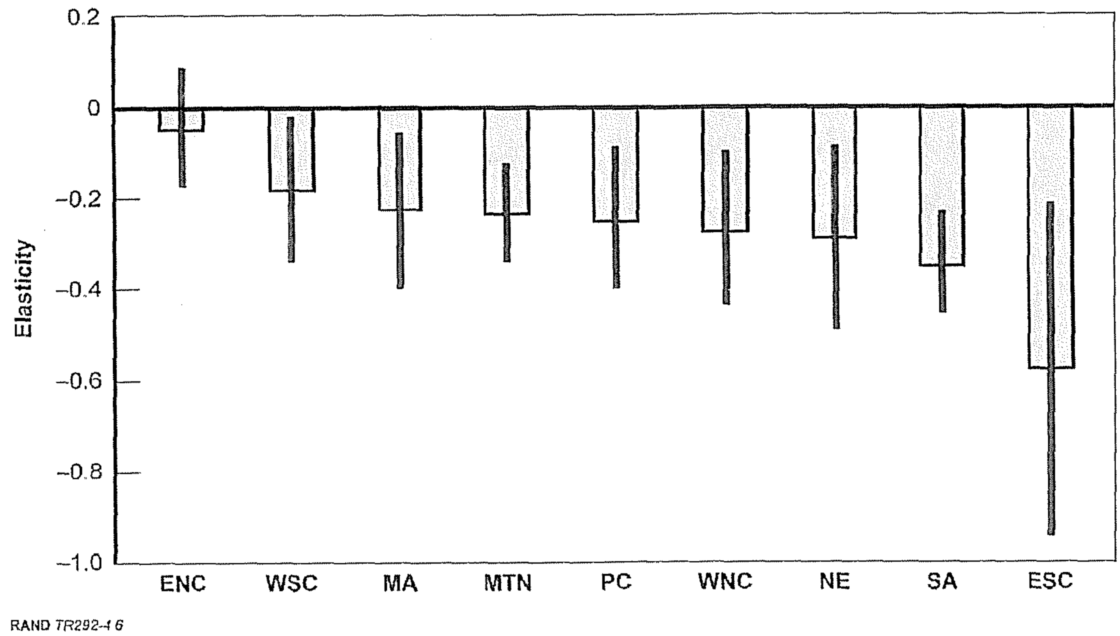

Figure 4.6: Estimated Long-Run Residential-Electricity Price Elasticities by Region, 1977–2004

When the various pieces of this analysis are brought together, they indicate that the relationship between demand and price vary enough by region that estimates of future residential electricity use or estimates of the impacts of energy-efficiency programs should reflect some of the regional variation.

Commercial Electricity Results

While the analysis of the residential electricity sector showed significant regional differences, the commercial electricity sector is somewhat less diverse. Our analysis of commercial energy intensity found some differences across regions, but the elasticities did not differ. The trend in electricity intensity per square foot of office space has been moving toward increased intensity, with slower increasing rates in the Pacific Coast and East South Central regions (see Figure 4.7). We cannot say that the Pacific Coast region is statistically different from zero in terms of commercial electricity intensity, and the West Southern Central and East Southern Central regions are significantly lower than most of the other regions. This finding indicates that new newly constructed buildings may be more energy efficient in some regions than in other regions. It may also indicate that the impacts of future improvements in commercial electricity efficiency may be larger regions with high growth in energy use, such as New England, the West North Central, and the South Atlantic, and might have little additional impact on the Pacific Coast region.

The short-run price elasticities for commercial electricity range from just under -.3 to -.15 (see Figure 4.8). Figure 4.8 indicates that some differences exist in short-run price elasticity estimates across regions, but they are smaller than the differences in such estimates across regions in the residential electricity sector. In addition, the commercial electricity estimates have considerably greater variance (larger confidence intervals) than the residential sector estimates. Given this large variance, there are no significant differences among regions. Although we cannot say the regions are statistically different from each other, it does appear that the Pacific Coast and East South Central regions are somewhat more elastic in terms of commercial electricity than the other regions, and one might look at these two regions somewhat differently than the others.

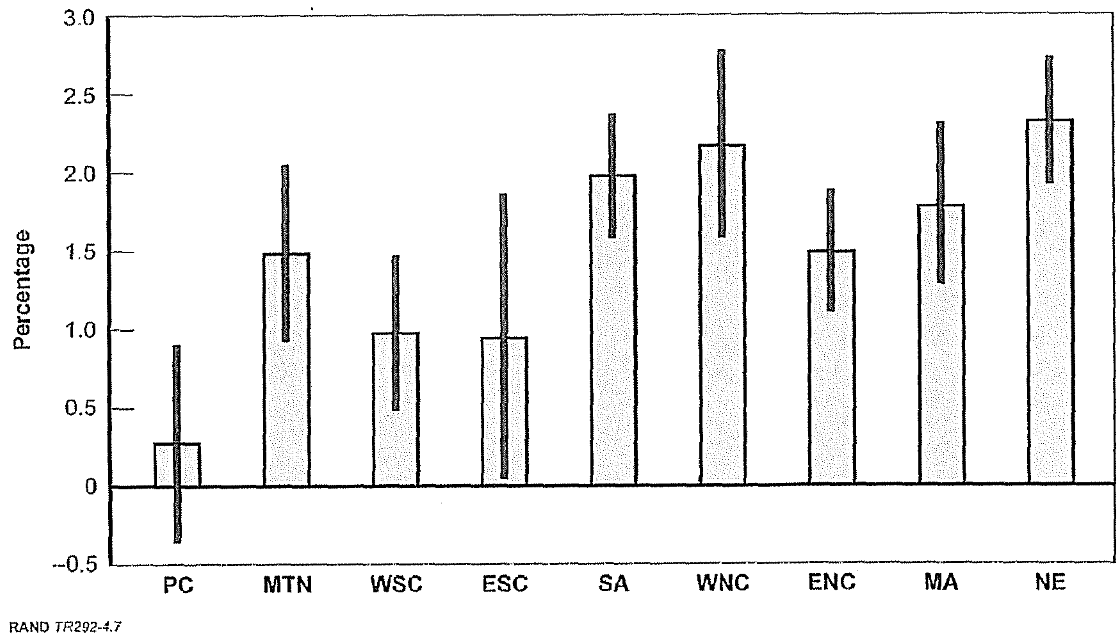

Figure 4.7: Regional Trends in Commercial Electricity Use per Square Foot of Office Space, 1977–1999

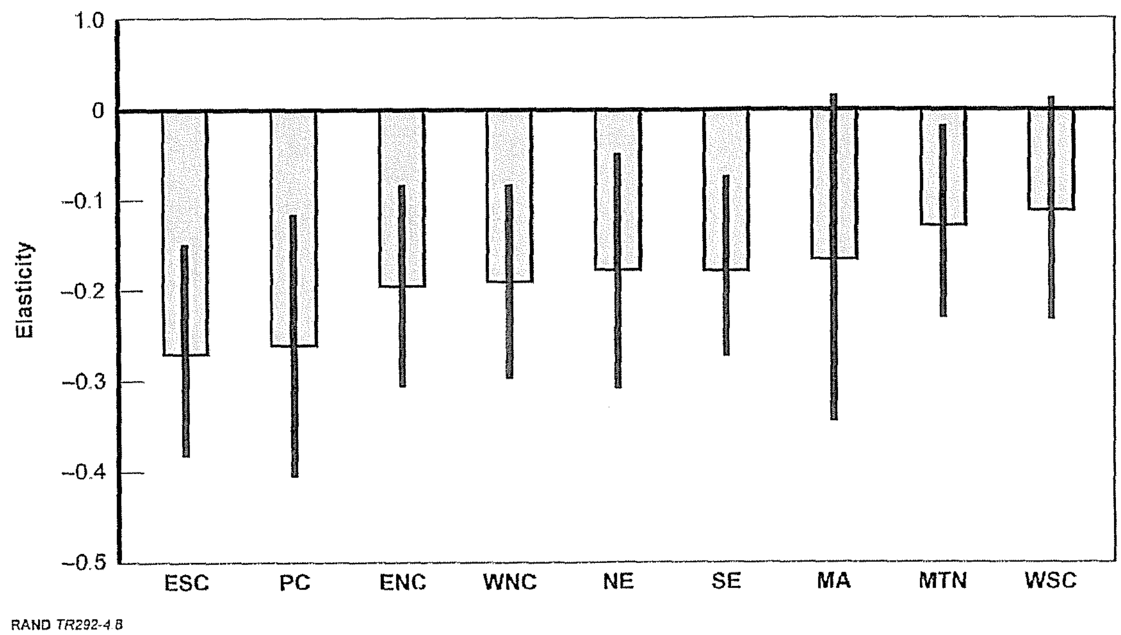

Figure 4.8: Short-Run Commercial Electricity Price Elasticities by Region, 1977–1999

Figure 4.9 shows that demand is more elastic in the long run than in the short run for the commercial electricity sector, but there is even less variation among the regions. The estimates shown in Figure 4.9 have large variances, and discerning differences in elasticities among the regions is not possible.

What we can conclude from the above discussion is that there are not many regional differences in commercial electricity use. Therefore, estimates of future electricity use at the regional level will not be greatly impacted by dissaggregation to the regional level, except perhaps for the Pacific Coast and East South Central estimates. Differences in elasticities among states are still possible, and those differences are assessed in Chapter Five.

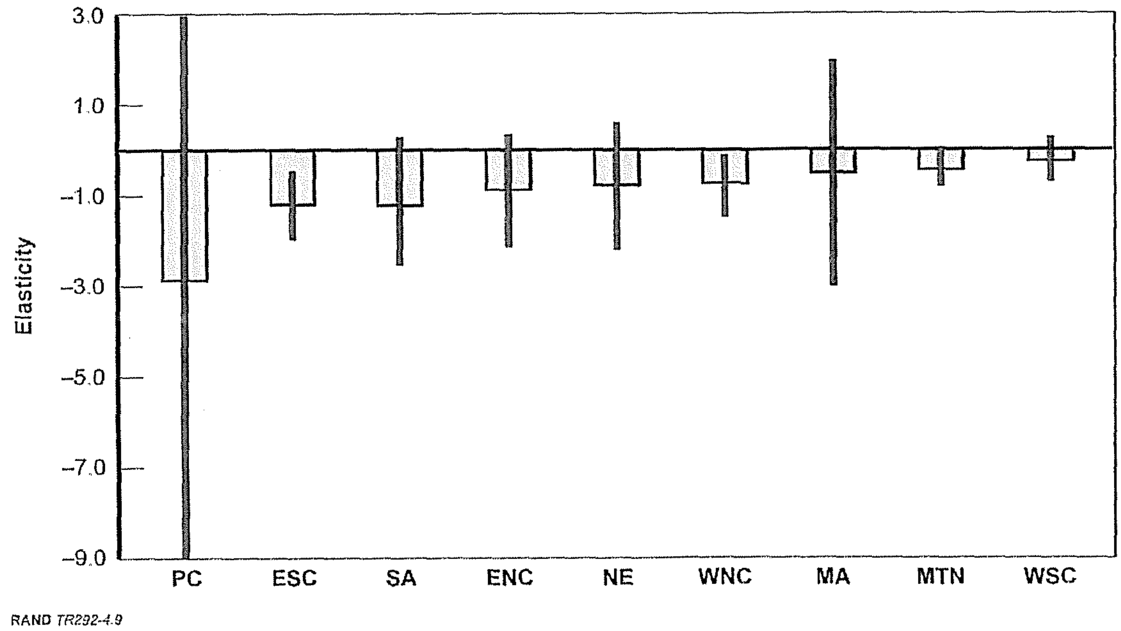

Figure 4.9: Long-Run Commercial Electricity Price Elasticities by Region, 1977–1999

Residential Natural Gas

Our analysis of residential natural-gas energy intensity and expenditures on natural gas as a share of income shows that there are differences in long-term trends among regions, although the trends themselves are small in magnitude. Figures 4.10 and 4.11 show intensity and price trends by region for natural gas. The largest increase in intensity is in the Pacific Coast, driven by Washington and Oregon, and the greatest decline in intensity is in the West South Central region, driven by Texas. There are large variations in the estimates; therefore, for the most part, we cannot distinguish among trends in intensity in the regions. Clearly, though, the Pacific Coast and Mid-Atlantic trends are positive, and the rest are negative (with the New England trend being indistinguishable from zero). This finding does suggest, however, that improvements in the efficiency of natural-gas-using appliances might have a bigger impact in the Pacific Coast and Middle Atlantic regions than they would in most other regions, and that additional improvements in the energy efficiency of natural-gas-using appliances in the West South Central region may have little impact.

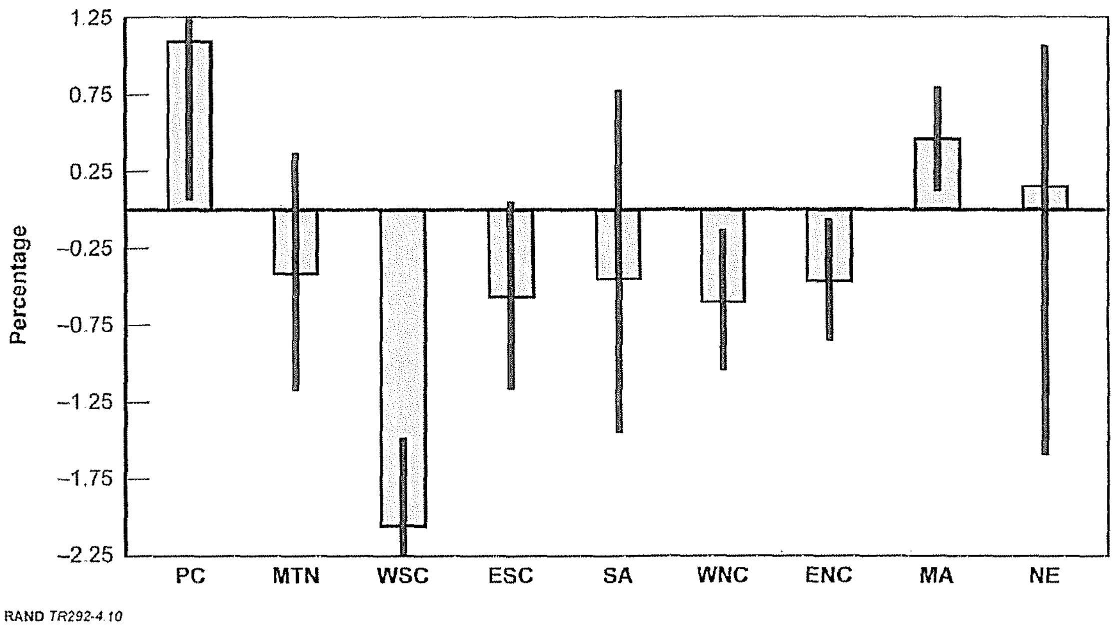

Figure 4.10: Natural-Gas Intensity Trends by Region, 1977–2004

The price trends for natural gas provide an interesting picture of the demand-price relationships one would expect. Increasing-price trends occurred in the regions with declining natural-gas intensity; the Pacific Coast and New England regions, which had increases in intensity, had an overall trend of prices not increasing (prices fluctuated across the sample for all the regions, but in the Pacific Coast and New England regions, the overall average trend was indistinguishable from zero). The sole exception to these trends is the Middle Atlantic region, which had small increasing price trends and increasing intensities. In Washington and Oregon, which were the primary drivers on the Pacific Coast for the increasing intensity, there has been some substitution of natural gas for electricity for heating purposes, some of which may have been driven by building codes that encouraged shifts from electricity for water heating. These results certainly indicate that some interesting results should be expected from the elasticity estimates.

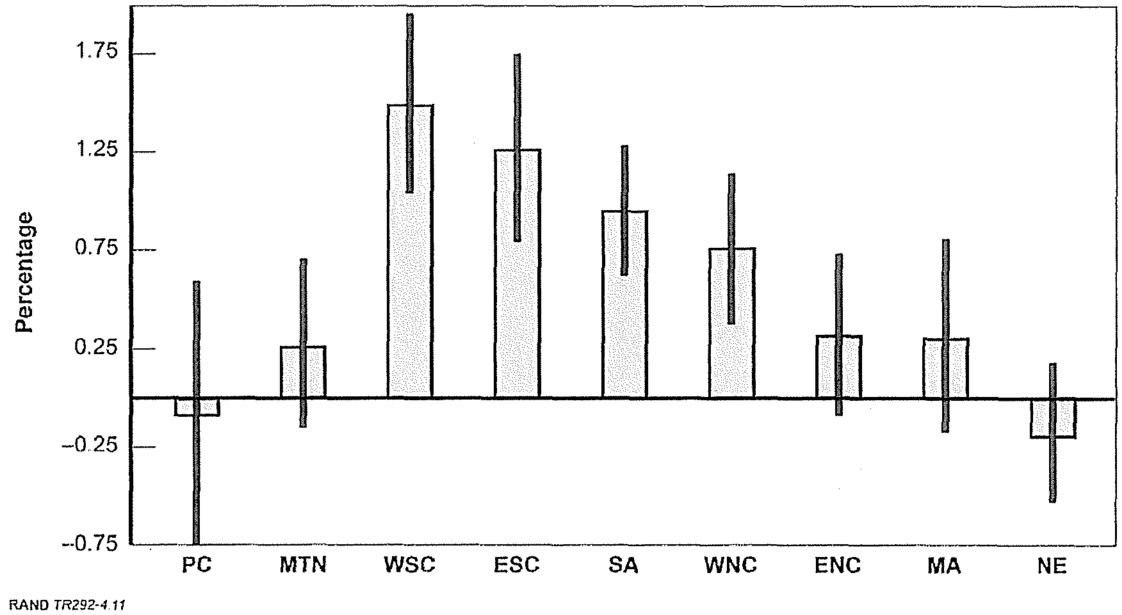

Figure 4.11: Natural-Gas Price Trends by Region, 1977–2004

Short-run price elasticity for residential natural gas varies from –0.03 for the West South Central region to –0.18 for the Pacific Coast (see Figure 4.12). The variance in the estimates, as in the commercial sector, is large. The Pacific Coast, again, has the greatest elasticity, and its neighboring Mountain region runs a close second. While we cannot say that the elasticity in these two regions is significantly different from that of the other regions, it may be worth further exploring benefits estimates for these two regions. Of the contiguous regions, the southern-state regions are the least elastic, and the northern-state regions are in the middle.

The long-run price-elasticity estimates (see Figure 4.13) are more elastic than the short-term estimates, with the most inelastic region still the West South Central and the most elastic still the Pacific Coast. While the variances are large in the long run, too, the Pacific Coast and Mountain regions are close to being significantly different from the West South Central, and there is a group in the middle with similar elasticities.

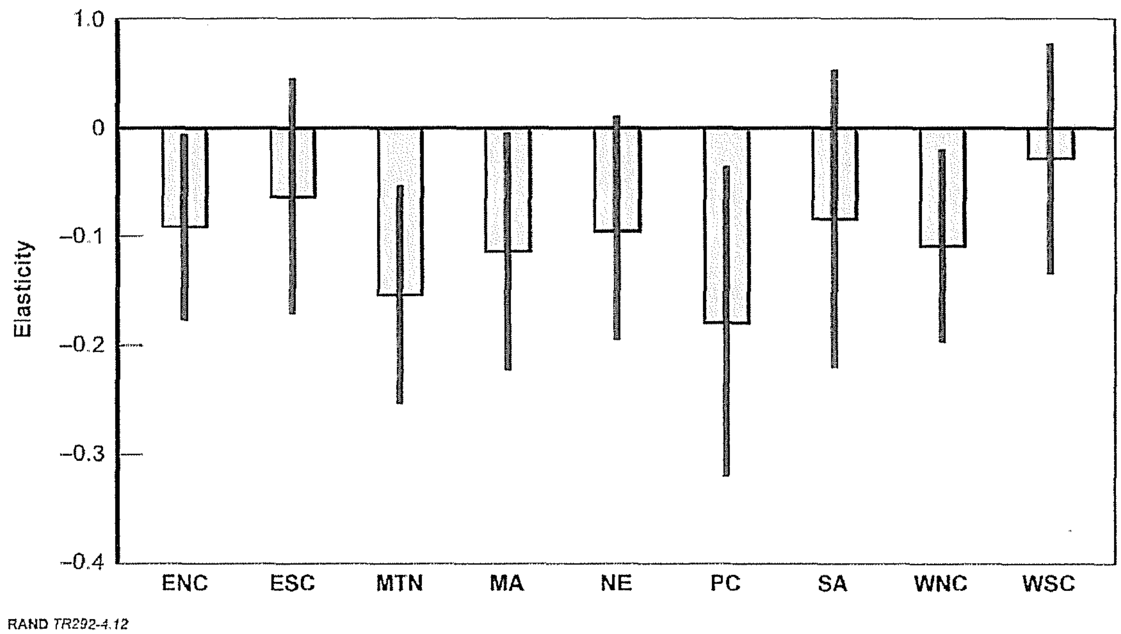

Figure 4.12: Short-Run Natural-Gas Price Elasticities by Region, 1977–2004

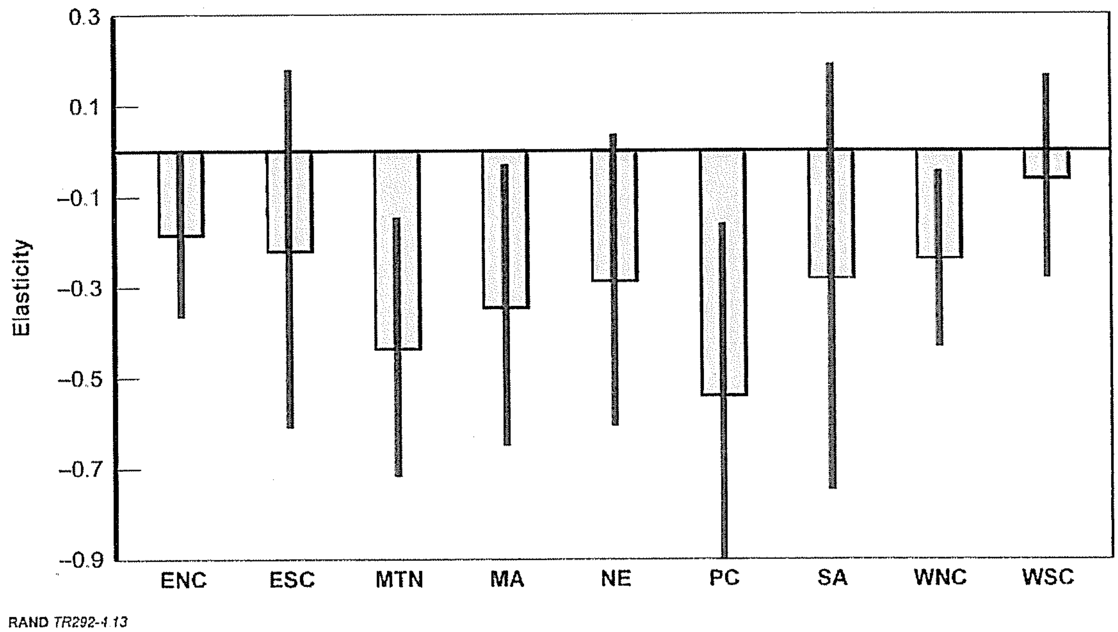

Figure 4.13: Long-Run Natural Gas Price Elasticities by Region, 1977–2004

The results for residential natural gas fall somewhere in between those for residential electricity and those for commercial electricity in terms of regional differences. As was the case with commercial electricity, there are few discernable differences in trends among the regions, but there are more differences in the elasticities than in commercial electricity, although still not at the level of significance that was seen in residential electricity. It might make a difference in forecasts and estimates if the Pacific Coast and Mountain regions are differentiated from the other regions.

Regional Analysis Conclusions

The analysis of regional-level differences in the price-demand relationship provides different answers for different markets. It seems clear that there are regional differences in the residential electricity market, and that estimates of the impact of energy efficiency and forecasts of electricity demand could differ significantly if the regional differences are taken into account. Clearly, commercial electricity does not appear to differ significantly by region; therefore, national-level estimates of commercial electricity price-demand relationships are likely to be sufficient for analyzing the impact of energy efficiency in the commercial sector. The picture for residential natural gas is somewhat different. There is not a lot of variability in energy-use trends over time, which is probably why there is not much difference by region in the price-demand relationship. It appears that demand responds more to price in two of the regions than in the others, and this finding could have some implications for estimates of the benefits of energy efficiency, but national level results in this case are probably also sufficient for analyzing the impact of energy efficiency in the commercial sector

Chapter 5: State-Level Analysis

In this chapter, we use a methodology similar to the one that was used for the analysis in the previous chapter, but in this case, we differentiate state-level elasticities and trends. The state-level analysis consists of an examination of trends and an estimation of short-run and long-run price elasticities for each state.

Residential Electricity

Beginning again with residential electricity, we look at the key trends in energy intensity and expenditures as a share of income. In terms of electricity use per capita (see Figure 5.1), there are only a few states, which are concentrated in the West and New England, with trends of small or declining energy intensity over the period studied. As we found in the regional-level analysis, the high-growth areas in terms of residential electricity usage are concentrated in the South. The significance of Figure 5.1 is in the consistency it shows within regions. While the energy intensity trends do vary within each region, they do not vary significantly. There are no regions with some states with declining intensity and some states with rapidly increasing intensity. This is a first indication that the regional-scale analysis might be sufficient for analyzing the impacts of energy efficiency.

We do observe some inter-regional variation in electricity expenditures as a share of income (see Figure 5.2). There is some diversity within each of the regions, although in most cases, the differences among states in a region are small except for a single state. Because the demand is consistent within regions, but the expenditures and prices are not, the elasticities in states in each region might vary.

Next, we take a look at the differences in estimated residential electricity price elasticities, which are illustrated in Figure 5.3. Each square-shaped plot point in the figure represents a U.S. state, and the vertical lines represent the 95 percent confidence interval. Sixteen states have an estimated elasticity that is positive over the period studied, although the variance is large enough in most cases that it is difficult to distinguish it from zero. There are a few possible explanations for this observation. In the early years that were studied, when prices were rising, these states saw consistent increases in demand, and in the later time period, when prices were declining in real terms, these states did not have rapid growth in demand. Therefore, overall, it would appear that the demand-price relationship reacts differently in these states than in other states. We caution, however, that it is possible that in the future, increases in prices in these states would not lead to increases in demand, but that the demand in these states would indeed slow or decrease in a manner similar to that in other states (although the elasticity might still be substantially less than that in other states).

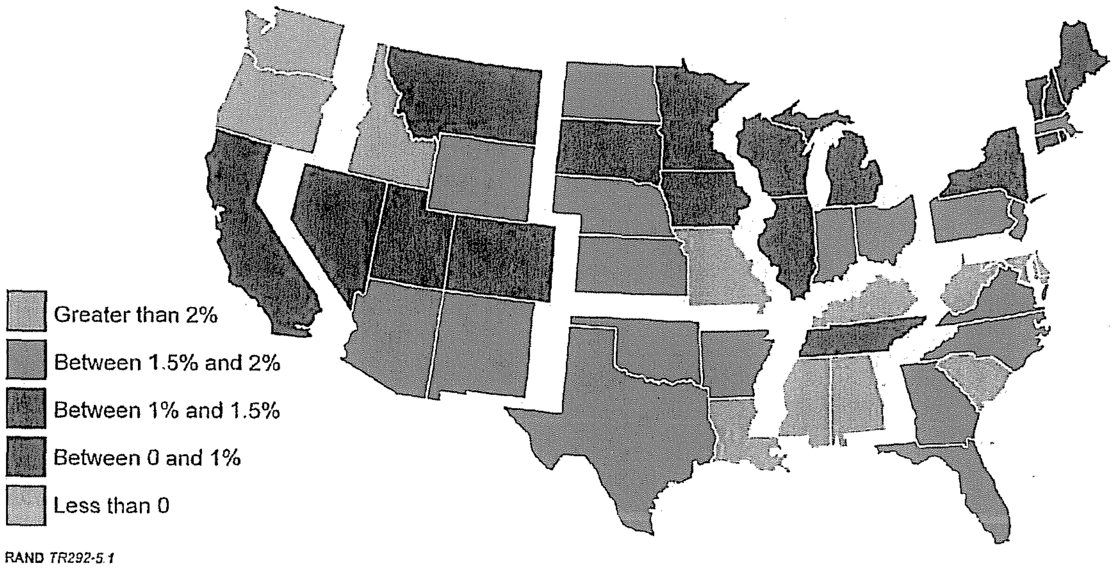

Figure 5.1: State-Level Trends in Residential Electricity Intensity, 1977–2004

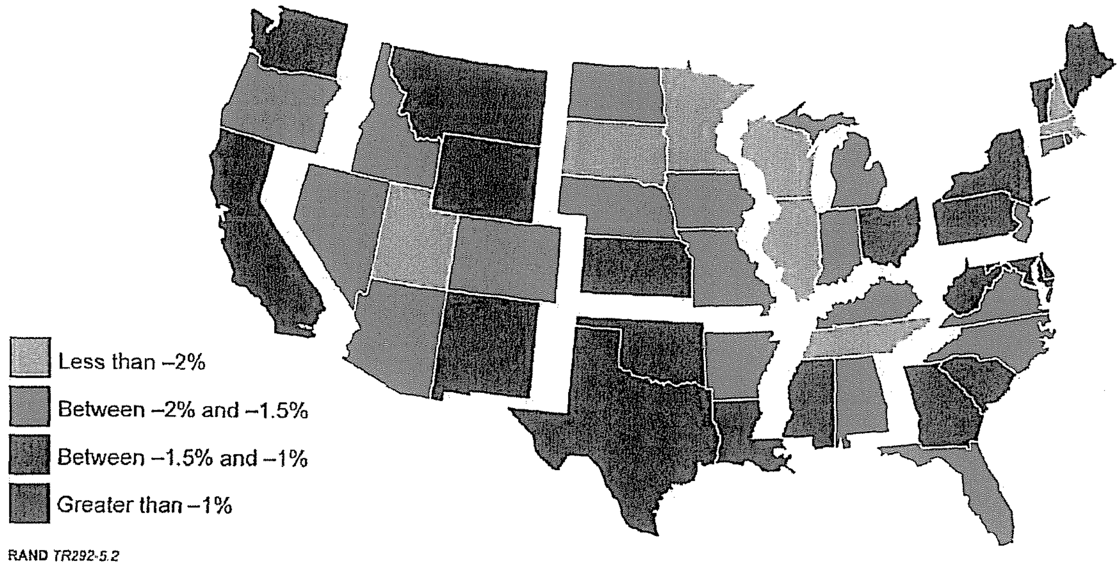

Figure 5.2: State-Level Trends in Residential Electricity Expenditures as a Share of Income, 1977–2004

One other finding of note, illustrated in Figure 5.3, is that there are ten states (represented by the squares on the right-hand side of the figure with positive elasticities) that are significantly different than 11 states represented by the squares on the left-hand side of the figure (all of which have elasticities less than –.2). Given the size of the variances, it is difficult to distinguish differences in price elasticities among the other states.

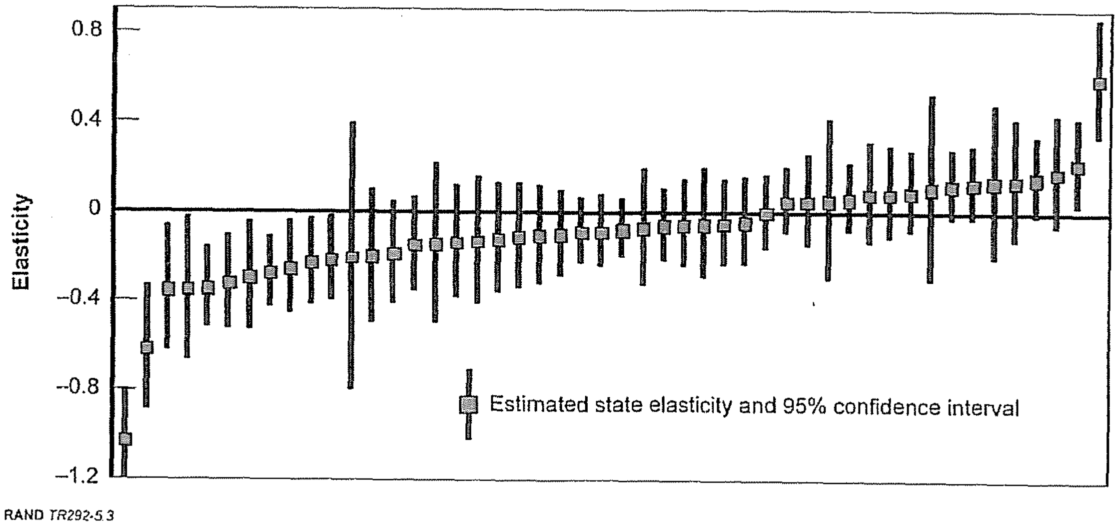

Figure 5.3: Estimates of Short-Run Residential Electricity Price Elasticities for Each State, 1977–2004

In Chapter Four, we illustrated significant differences in elasticities among regions. When we look at the individual state elasticities, some consistencies within the regions emerge. Figure 5.4 shows that several Mountain, West South Central, and West North Central states appear to have similar lower-positive or higher-positive price elasticities for residential electricity. Nevada, Idaho, Utah, Wyoming, Colorado, New Mexico, Oklahoma, Kansas, and Nebraska form a block of states with very inelastic demand (or estimated positive elasticities); the price-demand relationship in these states appears to be somewhat similar. Another broad region with notable results falls in the middle of the country and the Southeast. The group of states from Missouri to Florida has larger-than-average price elasticities, with the East South Central and South Atlantic regions showing some inter-regional inconsistencies. States within the Middle Atlantic region are consistent in terms of elasticities, as are the states in the East North Central region (with the exception of Wisconsin). This finding implies that even though there are considerable differences among the states in price elasticities, there are some regional consistencies. Therefore, disaggregation of data by region might still be sufficient for energy-efficiency impact analyses.

As one might expect, the geographic patterns in long-run price elasticity estimates (see Figure 5.5) are similar to those in the short-run price elasticity estimates. The Mountain states have inelastic demand, whereas states in the South Atlantic and East South Central, Pacific Coast, and New England region have more-elastic demand in the long run. The variance in the long-run elasticity estimates is larger than in the short-run estimates, and more states exhibit positive long-run price elasticities than positive short-run price elasticities. Overall, these findings seem to indicate that over the time period studied, electricity demand continued to rise in many of these states, regardless of price. Given the prices and demand that were observed over this time period, it is not clear whether any conclusions can be made about how long-run demand would react to price increases. We can say, again, that there appear to be regional differences, but consistencies among states within the regions, in the long-run price-demand relationship.

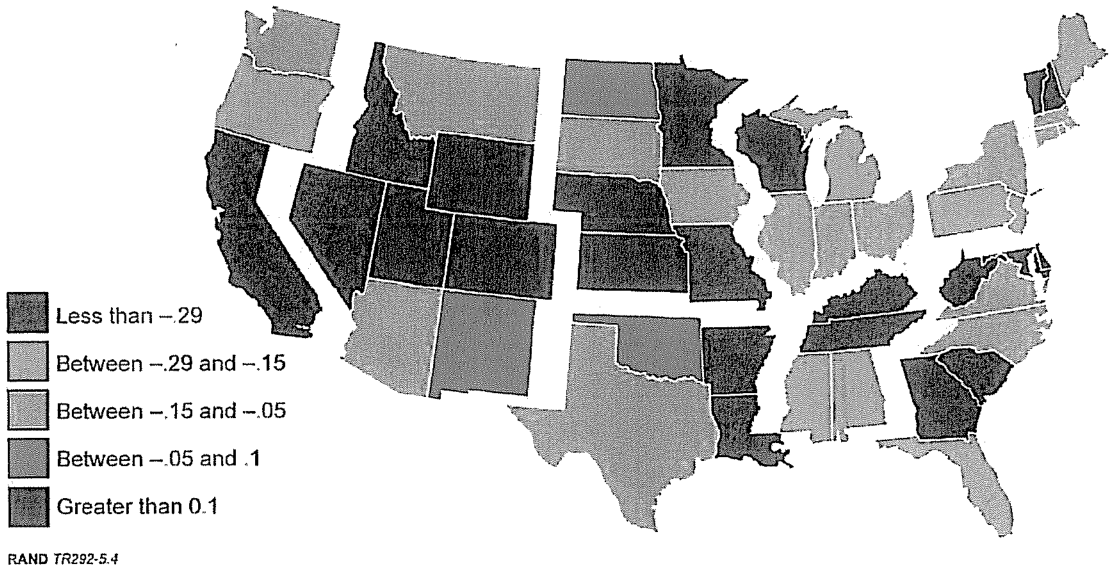

Figure 5.4: Estimated State-Level Short-Run Price Elasticities for Residential Electricity, 1977–2004

Overall, the findings presented in this section imply that while regional disaggregation will be important for estimating future impacts of energy-efficiency technology and forecasting demand for residential electricity, state-level disaggregation may not be necessary for that purpose.

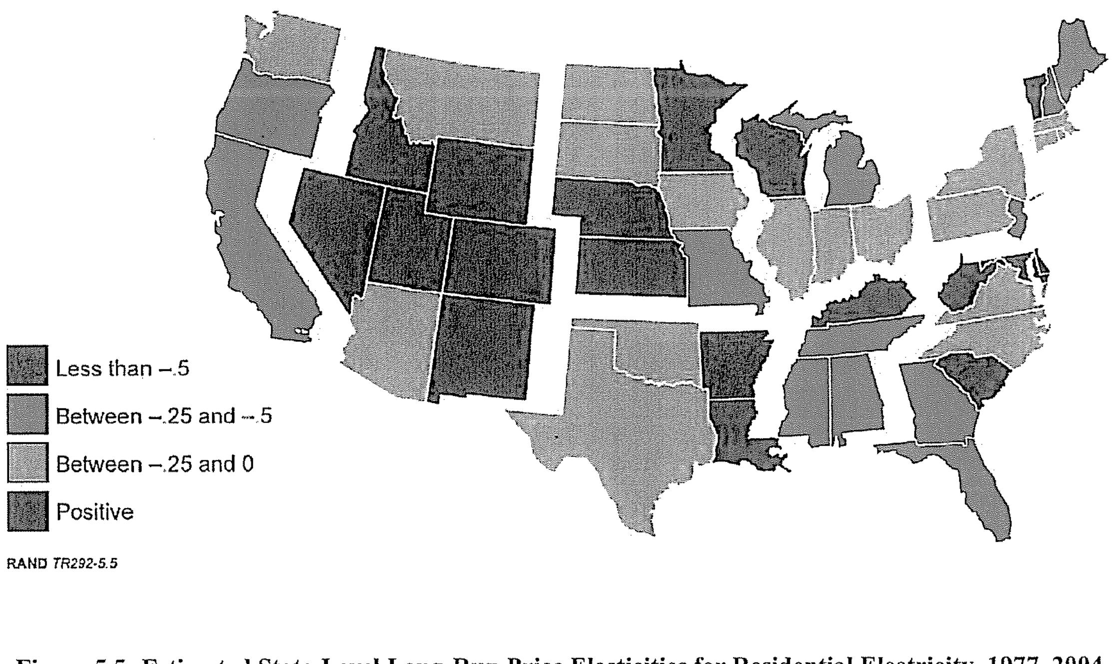

Figure 5.5: Estimated State-Level Long-Run Price Elasticities for Residential Electricity, 1977–2004

Commercial Electricity

The state-level analysis of the commercial electricity sector reveals a pattern of electricity usage similar to that at the regional level – there seems to be some state-level variation in electricity use patterns, but few differences in the price-demand relationship. Figure 5.6 shows trends in commercial electricity use per square foot of office space (i.e., the trends in intensity). We see the slowest growth in electricity use in states in the West, although a few of those states show a slow growth in intensity. There is some consistency in intensity among states within regions. For the most part, states within a region fall into one of two consecutive categories of growth. Again, this finding seems to indicate that the regional analysis would be sufficient to capture any differences that might exist in electricity intensity in the commercial sector.

The estimated elasticities in commercial-sector intensity are what we might expect from the previous sets of analysis. Figure 5.7 shows the estimated state-level short-run elasticities. There is not much variation across the states in intensity, except for a few that are represented at the left side of the figure. For the most part, the estimated elasticities range between –.5 and zero, with a few states with positive elasticity (that is not significantly different from zero), and a few states that seem to have more-elastic demand. It is interesting to note that for a large number of states, the variance is small, which means that the elasticities are well estimated. This is in contrast to the residential sector, in which the variance is large for a number of states. There is also more variation among the states in the residential-sector analysis in comparison with the commercial-sector analysis, which shows little variation among the states. We observed the same sort of patterns for the long-run elasticities.

Clearly, there does not seem to be a reason to disaggregate the analysis for commercial electricity to the state level.

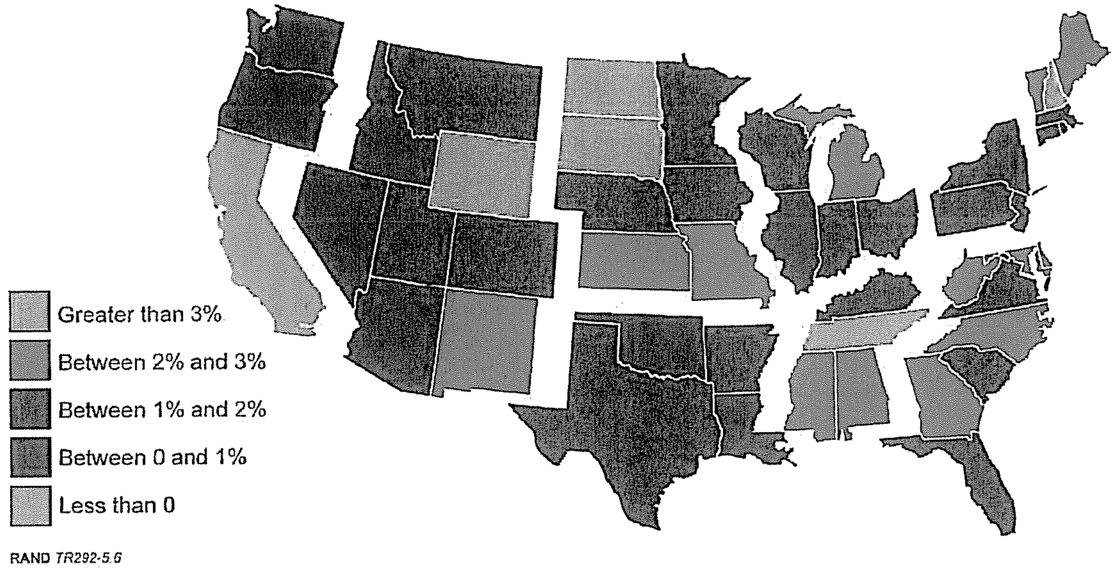

Figure 5.6: Estimated State-Level Trends in Electricity Intensity in the Commercial Sector, 1977–1999

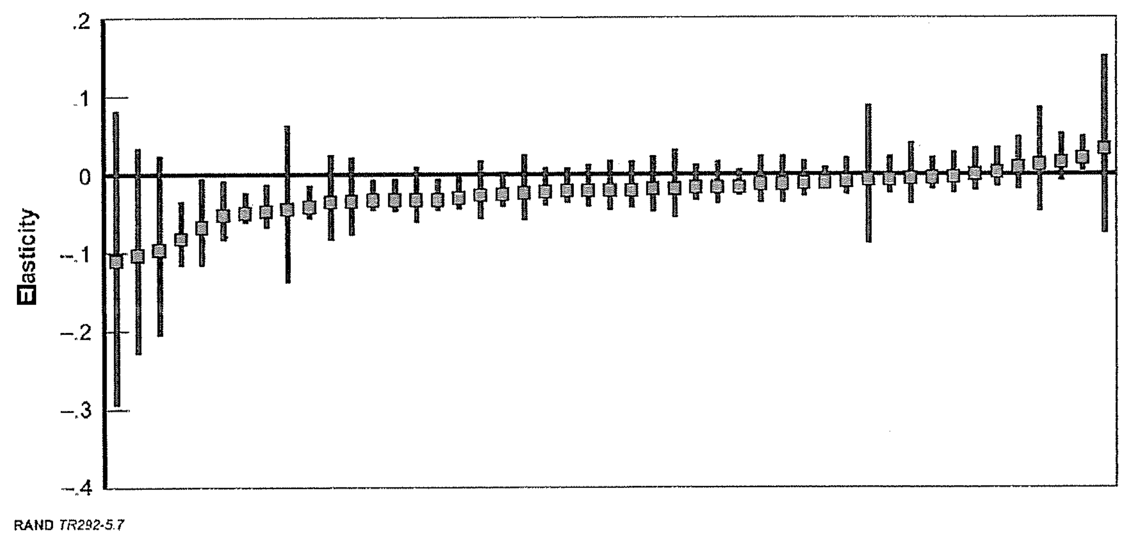

Figure 5.7: Estimated Short Run Elasticities in Electricity Intensity in the Commercial Sector at the State Level, 1977–1999

Residential Natural Gas

Because the regional-level results for residential natural gas showed little regional diversity and a lot of variance in the estimates, it is not surprising that we find basically the same results at the state level. There are differences among states, which become evident when looking at natural-gas intensity at the state level (see Figure 5.8). What is also evident is that there is significant variation among states within regions, with the notable exception of the East North Central and the West South Central, where the trends in natural gas use per capita are fairly consistent. Otherwise, there is not much in the way of observed patterns to note. There are more states in the North that have growing natural-gas intensities, but a group of states in the South Atlantic (and Tennessee) also have growing intensities.

Given these findings, it is not surprising that we also find some large differences among the states in estimated short-run price elasticities for natural gas (see Figures 5.9a and 5.9b) along with very large variances among the states. The price elasticities range from -.3 to .1, which is quite a broad range, but the variances are so large that we cannot even say that states at the extreme low end of the range are statistically different from other states. Reflecting what we observed at the regional level, there is not much in the way of consistency among states within the regions in terms of price elasticity. There is a group of contiguous states ranging from the middle of the country to the East Coast that have some similarities in elasticities. But again, because the variances are so large, there is not much we can interpret from these results, and there does not seem to be much of a reason to assess natural-gas demand and the benefits of energy-efficiency technologies at the state level.

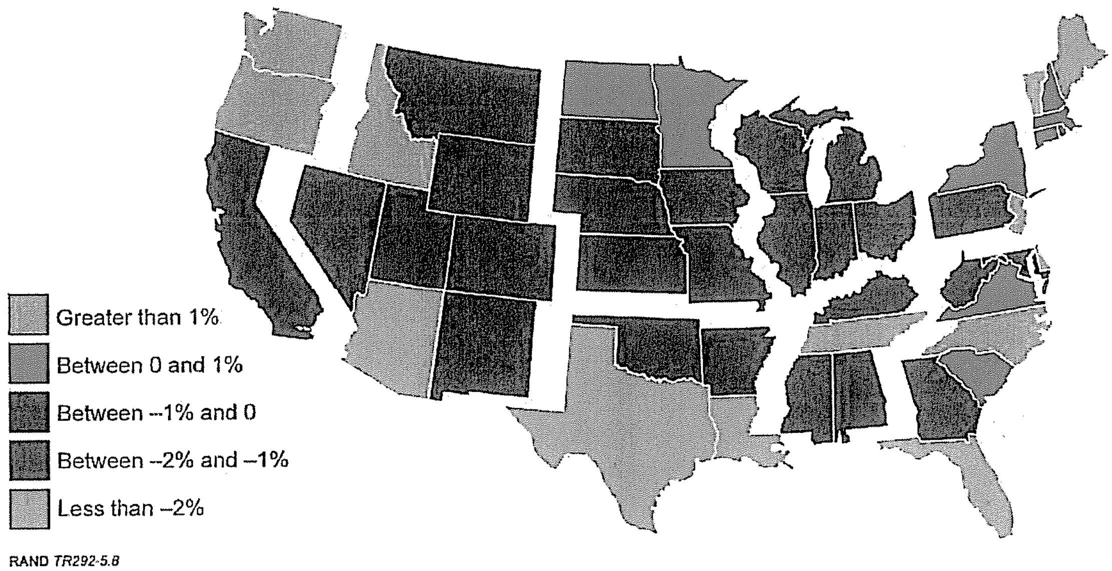

Figure 5.8: Trends in Natural-Gas Intensity at the State Level, 1977–2004

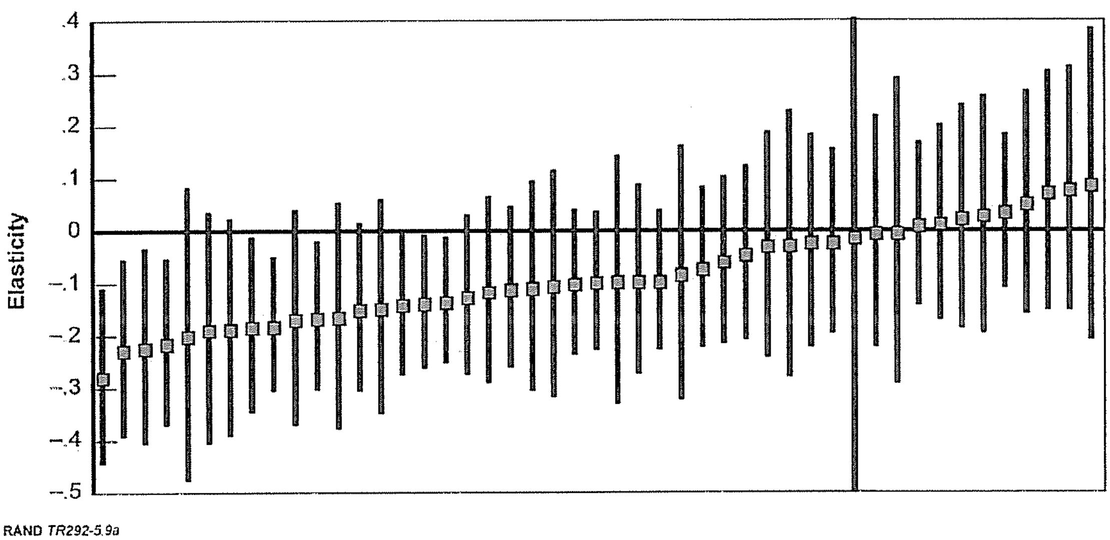

Figure 5.9a: Estimated Short-Run Price Elasticities for Natural Gas at the State Level, 1977–2004

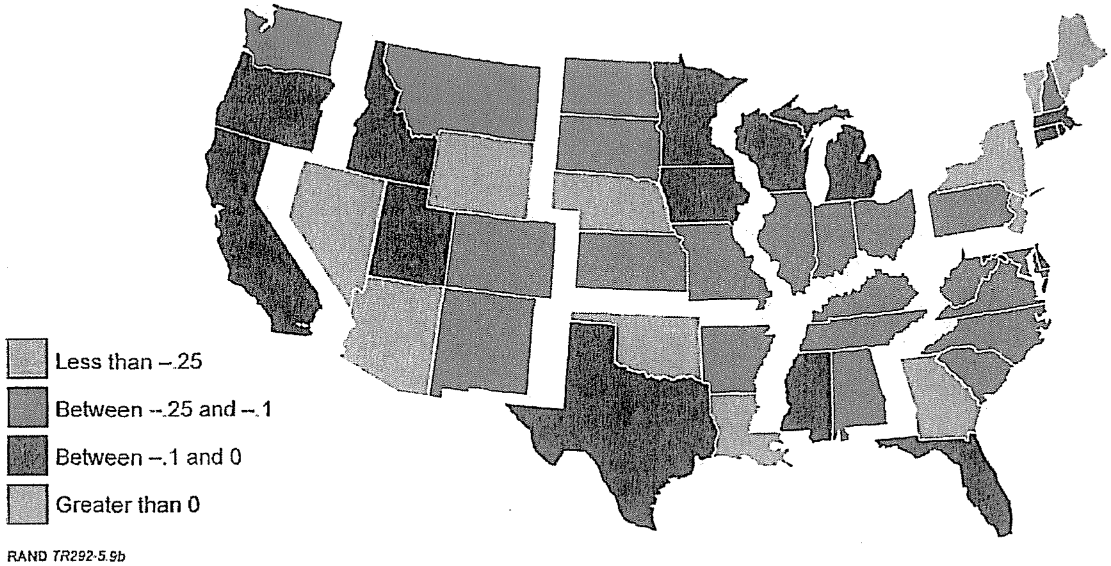

Figure 5.9b: Short-run Price Elasticities for Natural Gas

State-Level Conclusions

There are differences among the states in price elasticities and in some trends in energy use and other factors, but, for the most part, they are not significant. As was seen with the regional analysis, there is a difference between the results of the residential electricity analysis and those of commercial electricity and residential natural-gas analyses. For residential electricity use, there is enough consistency among states within regions that a state-level disaggregation would not likely produce different results than would regional-level analyses for forecasting the estimated benefits of energy-efficient technologies.

For commercial electricity and residential natural gas, there is not much consistency among states, and there are significant amounts of variance in the estimates; therefore, it is not certain that one could use our approach to differentiate states to a degree that would be useful in forecasting estimates of energy-efficiency benefits.

Chapter 6: Utility-Level Analysis

The utility-level analysis posed a number of analytical challenges, which limited the conclusions that we were able to draw from our analysis. While consumption and price data at the utility level were available in the database that we used, data on other factors that are key to the price-demand analysis (such as income and climate) were not. As such, we used state-level data in place of the unavailable utility-level data. Nevertheless, we continued with the experiment to see if there appear to be significant differences in how price and demand respond at the utility-scale level, simply to glean whatever information that might contribute to this study.

We did discover a few interesting things in this analysis. First, there is a lot of variation in elasticities among the utilities, which was not unexpected, although the price elasticities for about 65 percent of the sample are not statistically significant. Figure 6.1 illustrates the percentage of the sample of utilities that are in each region (shown in Figure 4.1), and of those, the percentage with estimated price elasticities that are statistically significant. There are no apparent regional consistencies, other than the South Atlantic and East North Central regions having the highest percentage of utilities with significant elasticities. For most regions, the percentage of utilities in the region and the percentage with significant estimates are very similar. At one end, the East North Central region had about 5 percent more utilities with statistically significant price elasticities, as a proportion of all utilities in the dataset, than the region's percent of the total number of utilities in the data set, and the Mountain region had more than 5 percent fewer utilities with statistically significant price elasticities.

The price-elasticity estimates are wide-ranging and have limited precision. The range of elasticities for the statistically significant estimates was 1.1 to –1.87. The median was –0.57, and the mean was –0.63.

Size of a utility appears to be correlated with the elasticity estimate. The range of elasticity estimates for the largest utilities (the median is –0.25, and the mean is –0.29) is similar to the range of estimates found in the state analysis. There is greater variability in the elasticity estimates observed in the small utilities, which results in a larger range of estimates.

Overall, we cannot conclude much from the utility-level analysis, other than the large amount of variation in price elasticities suggests that it may be useful to delve further into analyzing utility-level electricity demand. Further analysis may produce information that is valuable for planning and estimating energy efficiency at this level.

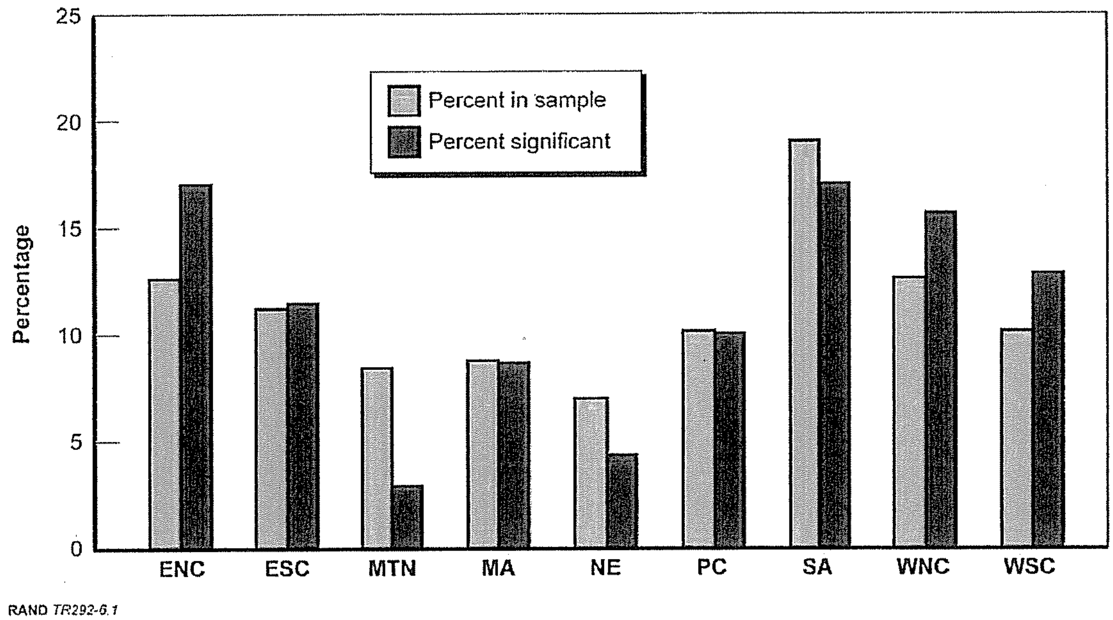

Figure 6.1: Percentage of Utilities in the Sample within Each Region and Percentage in Each Region with Significant Elasticities

Chapter 7: Conclusions, Final Thoughts, and Implications of Analysis

This chapter reviews the results of our analysis and their implications and presents our recommendations for further analysis. The key findings from this study are as follows:

- There are state and regional differences in (1) electricity and natural-gas demand, (2) the relationship between changes in demand and changes in price (i.e., elasticity), and (3) factors that influence demand.
- It is difficult, with the data we have available, to show statistically significant differences at all levels for commercial electricity and residential natural gas, though our results do indicate there may be regional and state differences in how price and demand interact in each of those sectors.
- We found significant regional differences in the price-demand relationship for residential electricity, but also found consistencies in the price-demand relationship for residential electricity among states within regions.
- The price-demand relationships have not changed over the past couple of decades—our estimates are about the same as those from studies done in the 1980s.
- Price elasticity—-i.e., how demand reacts to changes in price overall—has continued to be small since the 1980s.
- Over the periods we examined (1977–2004 for residential electricity and natural gas, 1977–1999 for commercial electricity, and 1989–1999 for residential electricity at the utility level), some basic trends emerged: Demand for energy overall is increasing; in many cases, energy intensity is increasing, but price is decreasing; and, while expenditures on energy are increasing, energy expenditures as a share of consumers' income and as a share of commercial sector output are declining.
- The past few years have seen some changes in these patterns, and it is possible that some of these trends and relationships might exhibit further changes.

Should DOE Disaggregate Data for Estimating Energy-Efficiency Programs Benefits?

The results of this study have a number of implications for the DOE's decisionmaking and policymaking. The basic question that was the impetus for this analysis was whether the DOE should disaggregate data (from the national level to the regional, state, or utility level) when estimating the benefits of its energy-efficiency programs. The answer to this question has a number of components.

We first made the case that certain factors might affect the impact that energy efficiency would have on overall demand. We also made the case that the price-demand relationship, or price elasticity, was important for estimating the impact of energy-efficiency programs and technology. In examining demand in each sector (residential and commercial electricity demand and residential natural-gas demand), we found that there are some differences in regional trends—in particular, trends in the intensity of energy use. Energy efficiency might have a bigger impact on regions with rapidly growing intensity of use than on regions with intensity that is either declining or growing slowly.

In terms of the price-demand relationship, if increasing prices motivate investments in energy efficiency, then the impact of energy efficiency might be greater in regions or states that are the most elastic (i.e., those with the lowest negative price elasticities). In these regions and states, the price-demand relationship is the most robust, and changes in price could lead to greater changes in energy efficiency, and vice-versa. Any estimates of the impact of energy-efficiency programs will be impacted by price elasticity, and if the elasticity differs significantly by region or state, the estimates of the impacts will differ accordingly.

In the case of the residential electricity sector, it is clear that there are regional differences. It also seems clear that the elasticities are relatively consistent among states within the regions and that, at least for the near term, disaggregating data on energy-efficiency programs to the regional level should be sufficient to evaluate the different effects that energy efficiency could have in different regions of the country.

The results are less clear for the commercial electricity sector. Few regions appear to have significantly different trends in the intensity of electricity use (specifically the Pacific Coast and perhaps the West North Central and East South Central regions, which have had slower growth). Statistically, it is difficult to distinguish among the other regions in terms of intensity of use, and there are no discernable differences in the price elasticities between regions. It does seem that the impact of energy efficiency in the Pacific Coast would differ from the impact in the rest of the country, and perhaps disaggregating Pacific Coast data from the national-level data is all that is needed to estimate the impact of certain DOE programs. On the other hand, there is some consistency in price elasticities among states within regions, such as what was seen in the residential electricity sector, although not to as great an extent. This finding does suggest that a state-level analysis would not be necessary in the short term.

The results are even less clear for the residential natural-gas sector. As in the commercial sector, only a couple of regions (again, the Pacific Coast and the West South Central region) seem to differ from the rest in all the factors we examined. But there is little consistency in the states within the DOE regions and little statistical difference among the estimated elasticities for each region. If one uses the estimated elasticities, the impact of energy-efficiency programs in the Pacific Coast and in the West South Central region would differ if one were to compare the two regions. This makes interpreting the findings on residential natural gas use more difficult than interpreting the findings for the other energy sectors. One finding of note is that the changes in demand for natural gas are smaller than those for electricity over the time period studied, so perhaps national-level analysis would be sufficient for determining the impact of energy-efficiency programs on demand in the residential natural-gas market.

Price Elasticity of Demand

The results on price elasticity are interesting. Our elasticity estimates are no different from those from ten to 20 years ago. This indicates that the relationship between price and demand has not changed even though (1) 15 to 20 additional years of empirical data are available; (2) there have been changes and shifts in energy use, in particular the introduction of new electricity-using devices; (3) there have been large increases in air-conditioning loads; and (4) appliances are more energy efficient than they were 15 to 20 years ago.

In addition, the elasticities remained the same over the past two decades—i.e., they remained low. In other words, demand did not tend to react much to changes in price. There are small, and somewhat consistent, changes, but on the surface it seems that there are few options for consumers or commercial businesses to switch to electricity or natural gas use in response to energy prices.

These observations, however, might be driven more by the trends in factors affecting intensity than by how consumers react to changes in price. Over the time period studied, we observed the following general trends:

- Energy prices heading downward
- Energy costs as a share of income also heading downward
- Energy use rising.

Given these trends, it is difficult to find significant variations in the price-demand relationship, because prices and demand have not varied much. Also, it is difficult to achieve improvements in energy efficiency when energy costs continue to decline, beyond those that "naturally" occur through technology improvements.

On the other hand, it is possible that the price-demand relationship is changing. First, just anecdotally, when California was facing energy problems in 2000 and 2001, a combination of factors led to a significant reduction in residential electricity use, with reductions in electricity demand estimated to be as high as 9 percent in response to government policy, media coverage, and rising prices. At least in a case such as that, consumers will change their demand behavior in the short term in response to energy prices and energy policy.

In the past few years, we have witnessed a reversal of the downward price trends and, at the same time, we have seen a reversal in the upward trend in electricity intensity in a number of states. Overall, prices have not been declining as rapidly, and energy use has not been increasing as rapidly either. So, it is possible that with an increasing-price regime, one might see a different demand-price relationship than what would be observed in a decreasing-price regime. More study and analysis would be needed to uncover these trends.

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Appendix A: Details on the Methodology Used to Estimate Elasticities

The primary goal of this study is to measure how the energy-demand relationship varies at different levels of spatial aggregation (i.e., at the national, regional, state, and utility level). We model the demand relationship as a function of four components:

- measured variables that vary across states and within states over time—such as energy prices, income, population, and climate
- fixed differences between states—unmeasured variables that do not change in the study period but that differ across states
- an aggregate time trend—one that accounts for unmeasured variables common to all states, such as federal policy
- a random error term that varies across and within states.

We estimate this model with the following fixed-effects specification:

$$Q^{D}_{i,t} = Q^{D}_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

where $Q^{D}_{i,t}$ is log energy demand in state *i* and year *t*, $Q^{D}_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g., energy prices, population, income, and climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The residual has three components:

- s_i is an indicator variable that captures time-invariant differences in energy demand across states ("state fixed effects").
- y_t is an indicator variable that captures time effects common to all states ("year fixed effects").
- $\varepsilon_{i,t}$ is a random error term.

We based this specification on the flow-adjustment model developed by Houthakker et al. (1974). In this model, demand is a function of prices, income, population, and climate.

$Q^{D*}_{i,t} = f(P_{i,t}, P^{C}_{i,t}, Y_{i,t}, Pop_{i,t}, Climate_{i,t})$

where Q^{D*} denotes desired demand in time t. The model assumes the following adjustment process between periods:

$Q^{D}_{i,t}/ Q^{D}_{i,t-1} = (Q^{D*}_{i,t}/ Q^{D}_{i,t-1})^{\theta}$

where $0< \theta < 1$. The estimating equation then becomes the following:

$$\ln Q^{D}_{i,t} - \ln Q^{D}_{i,t-1} = \theta \ln Q^{D^*}_{i,t} - \theta \ln Q^{D}_{i,t-1}$$

$$\ln Q^{D}_{i,t} = \theta \ln Q^{D^*}_{i,t} + \ln Q^{D}_{i,t-1} - \theta \ln Q^{D}_{i,t-1}$$

$$\ln Q^{D}_{i,t} = \theta \ln Q^{D^*}_{i,t} + (1-\theta) \ln Q^{D}_{i,t-1}$$

Then, by substituting in a linear function for $Q^{D^*}_{i,t}$, the final form is the following:

$$\ln Q^{D}_{i,t} = \theta \ln \alpha + \theta\gamma \ln p_{i,t} + \theta\beta \ln X_{i,t} + \theta\beta \ln X_{i,t-1} + (1-\theta) \ln Q^{D}_{i,t-1}.$$

In this model, the θ term reflects that current demand ($Q^{D}_{i,t}$)adjusts partially to changes in desired demand ($Q^{D^*}_{i,t}$). Energy demand does not fully adjust in the current period because it is a stock-flow process. In this stock-flow process, adjusting the stock usually takes more than one period but consumers can control the flow easily in the current period. Therefore, demand does not fully adjust within one period to changes in desired demand.

In more tangible terms, the "stock" refers to energy-consuming appliances that a consumer owns, such as a car, air conditioner, heater, and stove. The flow is the amount that the consumer uses the appliance. In this process, the consumer has immediate control over where the thermostat is set or how much he or she drives the car but these decisions can only affect energy consumption to a limited degree. If the consumer wants larger changes in energy demand, he or she must replace an expensive item like a car, heater, or air conditioner, which typically cannot happen immediately.

This explanation for the partial-adjustment process suggests that an ideal model for energy demand would explicitly represent consumer decisions on purchasing energy-consuming appliances and their levels of usage. Taylor (1975) discusses this issue and notes that most studies at that time had insufficient data on appliance purchases and usage to estimate such a model. Other studies have estimated price elasticity using models of this type, such as Dubin and Macfadden (1984). However, data limitations precluded estimating a similar model for different spatial scales. Therefore, we proceeded with Houthakker et. al.'s reduced-form model, which is commonly used in the literature.

By estimating the adjustment process (θ), we can estimate both short-run and long-run price elasticities. The short-run price elasticity is the long-run price elasticity (γ) multiplied by the adjustment factor (θ), which in this model refers to $\theta\gamma$, the estimated coefficient on the current period price variable. The long-run elasticity is estimated by subtracting the coefficient on the lagged demand variable ($1-\theta$) from one to get an estimate of θ and then dividing the coefficient of the current price ($\theta\gamma$) by the estimate of θ.

We estimate any spatial differences in the energy-demand relationship by adding interaction terms between indicator variables for the spatial unit of interest (region, state, or utility) and the regressors of interest (price, quantity, and income). These interaction terms allow the estimated parameters to vary, and we can analyze if price elasticities differ across geographical units.

Parameter Identification

The variables of interest in this study, energy price and quantity, are jointly determined by the interaction of energy supply and demand, which creates problems for identifying parameters in the demand equation. Ideally, we would model the energy market with a system of equations for supply and demand. With a system of equations, we could isolate movements in the demand and supply curves and use this variation to estimate the parameters in each equation. We were unable to develop a system of equations for each spatial level used in the study and instead used a reduced-form model that can identify the parameters of the demand equation under the following assumptions:

- the model includes all the factors that affect energy demand
- price changes between periods are exogenous
- the error term does not contain autocorrelation

The following discussion explains why these assumptions are necessary and then examines their plausibility.

The first assumption is necessary because identifying parameters of the demand equation, and more specifically the effect of prices on quantity, requires holding the demand curve fixed and allowing shifts in the supply curve to establish the shape of the demand curve. If the model was missing a factor that affected demand, then shifts in both demand and supply could cause the observed shifts in price and quantity but the model would attribute the changes solely to shifts in supply. More simply, the estimates in the demand equation could suffer from omitted variables bias.

The second assumption is required to isolate the effect of price on demand. In a full system of equations, changes in price affect demand and feed back into the supply equation. Therefore, prices are endogenous and determined by the equilibrium between supply and demand. Without a supply equation to capture this feedback, the model cannot identify the parameter on the endogenous variable, unless prices enter the system exogenously. The following discussion will examine some situations where prices could plausibly enter the system as an exogenous variable.

The final assumption is needed because the lagged demand term can be written as a function of past values of the error term. If autocorrelation is present, it creates correlation between the error term and the lagged demand variable, which biases estimates of the coefficient on lagged demand. The equations below show how autocorrelation is a problem.

The model equation is:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

which can be re-written as:

$$Q^D_{i,t} = \gamma\,(Q^D_{i,t-2}\gamma + X_{i,t-1}\beta + X_{i,t-2}\alpha + s_i + y_t + \varepsilon_{i,t-1}) + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

By continuing to substitute for the lagged demand term, this term could be re-written as a function of initial demand, lagged values of explanatory factors, and, most importantly, past values of the error term. Therefore, any autocorrelation in the error term ($E(\varepsilon_{i,t}, \varepsilon_{i,s}) \neq 0$ where $t \neq s$) will create correlation between the lagged demand term and the error term, which will bias estimates of the coefficient on lagged demand, γ.

The assumptions stated above for parameter identification are strong but not implausible. The following discussion addresses each assumption.

Assumption #1 - Controlling for all factors affecting demand

The model includes the own-price of the good, price of a substitute, and income, which are key variables in microeconomic decisions of demand. The model also controls for population and climate, which would also affect energy demand. In addition, the model includes lagged values of these factors, which controls for large period-to-period changes in explanatory variables. The model also controls for demand in the previous period, which in effect controls for the stock of energy-consuming appliances because the stock of appliances is unlikely to change significantly from year-to-year. Finally, the model includes fixed-effects for each cross-sectional unit and year.

The fixed-effects control for any unmeasured time-invariant effects on demand attributable to the cross-sectional unit. An example of an unmeasured time-invariant effect is energy demand patterns in states with federally-administered hydroelectric power sectors. Washington, Oregon, and Tennessee have exceptionally high per capita electricity use and low average prices. Some of this effect is due to prices, but each of these states have electricity markets dominated by large federal power agencies that have historically supplied the regions with inexpensive energy. The effect of these agencies is difficult to measure, and is likely to differ between states. Therefore, including an indicator variable for each state controls for the unique effects that agencies like the Bonneville Power Administration or Tennessee Valley Authority have on energy demand. In addition, the indicator variable controls for any other unmeasurable variables that affect energy demand. The year fixed effects control for any year-to-year variation in demand that occurs across all cross-section units. Examples of these effects are national legislation, macroeconomic trends, and national-level events that affect energy demand (war or terrorism attack).

The explanatory variables comprise a relatively comprehensive set of control variables for energy demand. The very high R^2 values (> 0.9) on the regressions indicate that the model fits the data well and explains a large amount of the variation in energy demand. One area where the model does not control for changes in demand is a state- or cross-section specific factor that changes over time. For instance, if a subset of states substantially changes their stock of energy-consuming appliances, then the model may not control for this change in demand. This situation contrasts with national consumer trends in purchasing new electronics, which the model can control for with year fixed effects.

Assumption #2 – Exogenous energy prices

The assumption of exogenous energy prices is the strongest assumption but not implausible. A public utilities commission that sets consumer rates regulates most electricity and natural gas rates. These price schedules do not change regularly and the rate setting is not exogenous. Despite these shortcomings, there are portions of a consumer's utility bill that do vary annually and this source of variation is arguably exogenous. Most utility bills contain a component that passes through changes in fuel prices to customers. Since utility rate schedules do not change regularly, much of the period-to-period variation in what consumers actually pay for electricity and natural gas is fluctuations in the fuel cost. Because these fuels are typically purchased at prices determined on national or world markets, the change in prices from fuel costs is primarily exogenous variation.

Assumption #3 – No autocorrelation in the error term

The discussion above showed that estimating the model with ordinary least squares (OLS) when autocorrelation is present will result in biased estimates. This assumption is testable and autocorrelation tests are performed on the regressions in the study. Alternate estimation methods are possible, notably instrumental variables and error component technique. In previous work, Houthakker et. al. (1974) found that OLS estimates with separate intercepts for cross-section units (fixed-effects) produced estimates that were comparable to the error component technique. Although, this finding is not generalizable to other data sets. Therefore, this analysis includes tests for autocorrelation.

We follow the test for first-order autocorrelation discussed in Wooldridge (1994; 2002). In this test, we run an OLS regression of the dependent variable on the explanatory variables and obtain the residuals. We then run an OLS regression of the residuals on the explanatory variables and lagged residuals. The coefficient on the lagged residual term is a consistent estimate for ρ and the t-statistic on the coefficient of the lagged residual term is a valid test for the null hypothesis $\rho = 0$ (no autocorrelation), where ρ represents the coefficient on the lagged error in an AR(1) model. In our results, we present the estimate of ρ and the associated t-statistic.

As stated earlier, an ideal model would include a system of equations to model the demand and supply equations of each state's energy market. The limited scope of this study excluded an extensive analysis of supply and demand in each state. We followed Houthakker's demand model because it was widely used in the literature, we could estimate differences in short- and long-run elasticities, and determine if these parameters vary geographically. Under the assumptions stated above, the model will estimate the causal effect of prices on energy demand—the focus of this study and measure how this effect varies geographically. If these conditions are not met, the estimate will reflect the correlation between the observed prices and quantities

Trend Analysis

The regional data analysis for each energy market in Chapter Four displays regional trends for residential electricity, commercial electricity, and natural gas intensity, expenditures, and expenditures as a share of income. We estimate these trends using a deterministic time trend of the following form:

Ln dependent variable = $\beta_0 + \beta_1$ year + ε

This model fits a linear time trend to our data. In most of the analyses done for this study, the trends were linear, and the model was a good fit, which was evidenced by R^2 over 0.9 (the time trend). Appendix D displays the results from the trend analysis.

Appendix B: Data Sources

The regression analyses done for this study used panel data for the 48 contiguous states. The time periods for each energy market analysis varied because of data limitations. The data on the residential electricity and natural gas markets spans 1977 to 2004. The data on commercial electricity extends only from 1977 to 1999. The data are from the following four sources: the DOE EIA, Bureau of Economic Analysis (BEA) of the Department of Commerce, the U.S. Census Bureau, and the National Oceanic and Atmospheric Administration (NOAA).

Energy Data

The sources for electricity data include the following EIA publications: *State Energy Data Report 2001*, *Electric Power Annual,* and *Electric Power Monthly.* By combining these data sources, we developed a state-level database of electricity consumption and prices for residential and commercial customers. The sources of natural-gas data include the following EIA publications: *State Energy Data Report 2001*, *Natural Gas Annual,* and *Natural Gas Monthly.* As was done for the electricity sector, for natural gas we created a state-level database on consumption and prices for residential customers.

Economic Data

We obtained economic data on gross state product, GDP deflator, and population from the Department of Commerce Bureau of Economic Analysis (BEA) "Regional Economic Accounts" Web site (see http://www.bea.gov/bea/regional/data.htm). We purchased data on commercial floorspace from McGraw-Hill Construction Dodge (http://dodge.construction.com).

Climate Data

The NOAA publishes state-level data on heating and cooling degree days. The degree-day measures quantify how far the daily average temperature deviates from 65 degrees. For instance, if a day's average temperature is 50 degrees, then the day has 15 heating degree days. If the average is 70, then the day has five cooling degree days. We constructed an annual climate index by summing heating and cooling degree-day measures, which captures annual climate variation in each state. The data on degree days are available on the NOAA website (http://lwf.ncdc.noaa.gov/oa/documentlibrary/hcs/hcs.html).

Appendix C: Variables and How They Were Constructed

Table C.1: Residential Electricity Regression Analysis Variables

Variable	How Variable Was Constructed/Data Source
Residential electricity consumption	Electricity consumption (Btus), residential sector (ESRCB), 1977-1999 Source: EIA *State Energy Data Report* (2001) Electricity sales (megawatt hours), residential consumers, 2000-2004 *Source*: EIA *Electric Power Annual* (2003) and *Electric Power Monthly* (2004)
Real residential electricity prices = Nominal residential electricity price / GDP deflator	Average price of electricity, residential sector (ESRCD), 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001) Average price of electricity, residential consumers, 2000-2004 *Source*: EIA *Electric Power Annual* (2003) and *Electric Power Monthly* (2004)
Real residential natural gas prices Nominal residential natural gas price / GDP deflator	Average price of natural gas, residential sector (NGRCD), 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001) Average price of natural gas, residential consumers, 2000-2004 *Source*: EIA *Natural Gas Annual* (2003) and *Natural Gas Monthly* (2004)
Population	State population *Source*: BEA, *Regional Accounts Data*, "Annual State Personal Income," Population table (no date)
Real disposable income per capita = Disposable Income per capita / GDP deflator	Disposable income per capita *Source:* BEA, *Regional Accounts Data*, "Annual State Personal Income," Per capita disposable personal income table (no date)
Climate index = Heating degree days + Cooling degree days	Heating degree days, cooling degree days *Source:* NOAA, *National Climatic Data Center*, "Heating and Cooling Degree Data" (no date)

Table C.2: Commercial Electricity Regression Analysis Variables

Variable	How Variable Was Constructed/ Data Source
Commercial electricity consumption	Electricity consumption (Btus), commercial sector (ESCCB) 1977-1999 *Source*: EIA *State Energy Data Report* (2001)
Real Commercial Electricity Prices = Nominal commercial electricity price / GDP deflator	Average price of electricity, commercial sector (ESCCD) 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001)
Real Commercial Natural Gas Prices	Average price of natural gas, commercial sector (NGCCD) 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001)
Area of commercial floorspace	Data purchased from McGraw-Hill Construction Dodge http://dodge.construction.com/—includes data on square footage of commercial floor space from 1977 - 1999 for each sate
Real gross state product = Gross state product / GDP deflator	Gross state product *Source:* BEA, *Regional Accounts Data*, "Gross State Product," (no date)
Climate index = Heating degree days + Cooling degree days	Heating degree days, Cooling degree days *Source:* NOAA, *National Climatic Data Center*, "Heating and Cooling Degree Data" (no date)

Table C.3: Residential Natural-Gas Regression Analysis Variables

Variable	How Variable Was Constructed/ Data Source
Residential natural gas consumption	Natural gas consumption (Btus), residential sector (NGRCB) , 1977-1999 *Source*: EIA *State Energy Data Report* (2001) Natural gas sales (thousands of cubic feet), residential consumers, 2000-2004 *Source*: EIA *Natural Gas Annual* (2003) and *Natural Gas Monthly* (2004)
Real residential natural gas prices = Nominal residential natural gas price / GDP deflator	Average price of natural gas, residential sector (NGRCD) 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001) Average price of natural gas, residential consumers, 2000-2004 *Source*: EIA *Natural Gas Annual* (2003) and *Natural Gas Monthly* (2004)
Real residential electricity prices = Nominal residential electricity price / GDP deflator	Average price of electricity, residential sector (ESRCD) 1997-1999 *Source*: EIA *State Energy Price and Expenditure Report* (2001) Average price of electricity, residential consumers, 2000-2004 *Source*: EIA *Electric Power Annual* (2003) and *Electric Power Monthly* (2004)
Population	State population *Source*: BEA, *Regional Accounts Data*, "Annual State Personal Income," Population table (no date)
Real disposable income per capita = Disposable income per capita / GDP deflator	Disposable income per capita *Source:* BEA, *Regional Accounts Data*, "Annual State Personal Income," Per capita disposable personal income table (no date)
Climate index = Heating degree days + Cooling degree days	Heating degree days, cooling degree days *Source:* NOAA, *National Climatic Data Center*, "Heating and Cooling Degree Data" (no date)

Appendix D: Regression Analysis Results

In this appendix, we present the results from regression analysis at the national, regional, state, and utility levels of aggregation. We display the results for each energy market by level of aggregation.

National-Level Results

This section shows results for the residential electricity, commercial electricity, and residential natural gas markets. In the national level regressions, we estimate the model using panel data from the 48 contiguous states. We estimate the following model for these regressions:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + s_i + y_t + \varepsilon_{i,t}$$

where $Q^D_{i,t}$ is log energy demand in state *i* and year *t*, $Q^D_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g. energy prices, population, income, and climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The s_i term is a state-fixed effect estimated with an indicator variable. The y_t term is a year-fixed effect also estimated with an indicator variable and $\varepsilon_{i,t}$ is a random error term.

Residential Electricity

The dependent variable in this regression was the log of electricity sold to residential electricity consumers. We controlled for the following variables:

- Lag value of dependent variable
- Log of residential electricity price
- Lag value of log of residential electricity price
- Log of per capita income
- Lag value of log of per capita income
- Log of state population
- Lag value of log of state population
- Log of residential natural gas price
- Lag value of log of residential natural gas price
- Log of climate index (heating degree days + cooling degree days)

The residential electricity market regression analysis covers the period from 1977-2004. The data from 2001 are excluded from the analysis because EIA had serious errors in the data for that year, which they have not corrected yet.

The results show that lagged quantity has a significant and positive effect on current period consumption. Current and lagged electricity prices are significant and negative. The estimates indicate that short run price elasticity (-0.24) is inelastic and similar to previous estimates in the literature. The income, population, and natural gas variables are all insignificant in the current period and significant in the lagged period. The lagged values are all positive, which is expected. Income and population increases should correspond with greater electricity demand. In this case, we consider natural gas a substitute for electricity and the positive sign for the cross-price elasticity indicates it is a substitute. Finally, the climate index has a significant and positive effect on residential electricity demand.

Table D.1: Regression results from the residential electricity market

	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
Lag quantity	0.232	0.058	4.03	0	0.119	0.345
Ln elec price	-0.243	0.049	-4.96	0	-0.339	-0.147
Lag elec price	-0.129	0.048	-2.7	0.007	-0.222	-0.035
Ln income	0.003	0.076	0.04	0.968	-0.146	0.152
Lag income	0.384	0.073	5.27	0	0.241	0.527
Ln population	-0.225	0.285	-0.79	0.43	-0.783	0.334
Lag population	0.827	0.307	2.69	0.007	0.225	1.428
Ln nat gas price	-0.005	0.028	-0.16	0.873	-0.06	0.051
Lag nat gas price	0.111	0.031	3.58	0	0.05	0.172
Ln climate	0.246	0.026	9.36	0	0.194	0.298

$R^2 = 0.99$
N = 1237

The adjusted R-squared for this model is very high—approximately 0.99. A high R-squared is typical with fixed effects models because the state and year effects included in the model usually have considerable explanatory power.

We tested for first-order autocorrelation in the error term. The estimate of ρ was -0.009 with a t-statistic of -0.69, which indicates first-order correlation is not present. We, therefore, conclude that autocorrelation does not affect consistency of the coefficient estimates or validity of the standard errors.

Commercial Electricity

The dependent variable in this regression was the log of electricity sold to commercial electricity consumers. We controlled for the following variables:

- Lag value of dependent variable
- Log of commercial electricity price
- Lag value of log of commercial electricity price
- Log of gross state product
- Lag value of log of gross state product
- Log of commercial floorspace
- Lag value of log of commercial floorspace

- Log of commercial natural gas price
- Lag value of log of commercial natural gas price
- Log of climate index (heating degree days + cooling degree days)

Table D.2: Regression results from the commercial electricity market

	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
Lagged quantity	0.785	0.034	22.81	0	0.717	0.852
Ln elec price	-0.209	0.060	-3.47	0.001	-0.327	-0.091
Lag elec price	0.148	0.052	2.85	0.004	0.046	0.250
Ln nat gas price	-0.023	0.020	-1.18	0.236	-0.061	0.015
Lag nat gas price	0.049	0.022	2.19	0.029	0.005	0.093
Ln commercial GSP	0.155	0.124	1.25	0.211	-0.088	0.398
Lag commercial GSP	-0.039	0.122	-0.32	0.747	-0.279	0.200
Ln floorspace	0.504	0.339	1.49	0.138	-0.162	1.169
Lag floorspace	-0.421	0.305	-1.38	0.169	-1.020	0.179
Ln climate	0.233	0.039	5.92	0	0.156	0.310

R^2= 0.99
n = 1034

The commercial electricity market regression analysis covers the period from 1977-1999. Later data are not included in the analysis because of consistency problems with gross state product data collected by the Bureau of Economic Analysis. In addition, data from Tennessee were excluded from this regression.

The results show that lagged quantity has a significant and positive effect on current period consumption. The magnitude is larger than the estimate for residential electricity. Current electricity price is significant and negative. The estimate indicates that short run price elasticity (-0.21) is also inelastic and similar to previous estimates in the literature. The lagged electricity price is positive and significant, which is not expected. The estimates for natural gas are insignificant for the current period and significant and positive for the lag period. Again, this suggests that natural gas is a substitute but the cross price elasticity is small. All of the GSP and floorspace variables were insignificant. Finally, the climate index has a significant and positive effect on commercial electricity demand. The magnitude is also similar to the residential electricity estimate.

The adjusted R-squared for this model is also very high—approximately 0.99. This, again, indicates the state and year effects included in the model have considerable explanatory power.

We also tested for first-order autocorrelation in the error term. The estimate of ρ was 0.021 with a t-statistic of 0.47. These results suggest first-order correlation does not affect the coefficient estimates and standard errors in this model.

Residential Natural Gas

The dependent variable in this regression was the log of natural gas sold to residential natural gas consumers. We controlled for the following variables:

- Lag value of dependent variable
- Log of residential natural gas price
- Lag value of log of residential natural gas price
- Log of per capita income
- Lag value of log of per capita income
- Log of state population
- Lag value of log of state population
- Log of residential electricity price
- Lag value of log of residential electricity price
- Log of climate index (heating degree days + cooling degree days)

Table D.3: Results from natural gas market regression analysis

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Lag quantity	0.577	0.024	24.44	0	0.531	0.623
Ln nat gas price	-0.132	0.031	-4.24	0	-0.193	-0.071
Lag nat gas price	-0.106	0.031	-3.42	0.001	-0.167	-0.045
Ln elec price	0.034	0.053	0.64	0.521	-0.070	0.138
Lag elec price	0.146	0.052	2.8	0.005	0.044	0.248
Ln income	0.261	0.123	2.13	0.034	0.020	0.503
Lag income	0.167	0.113	1.48	0.139	-0.054	0.388
Ln population	1.169	0.449	2.6	0.009	0.287	2.051
Lag population	-0.717	0.449	-1.6	0.11	-1.598	0.163
Ln climate	0.181	0.042	4.29	0	0.098	0.264

$R^2 = 0.96$
n = 1210

The residential natural gas market regression analysis covers the period from 1977-2004. The regression includes data from all time periods. It excludes the state of Maine from the analysis. Gas volumes sold in Maine are very small in absolute terms and relative to all other states. Since the absolute volumes traded are small, small changes had large effects in % changes and disproportionately affected the price elasticity estimates. Since the market there is small compared to the rest of the country, the analysis excludes it.

The results show that the lagged quantity is significant and the magnitude is similar to the estimate in commercial electricity. Natural gas price is significant and negative in the current and lagged period. The estimate of short-term price elasticity is –0.132, which is smaller in absolute value than the estimates for both electricity markets. The current price of electricity is insignificant but the lagged value is positive and significant. This is further evidence that electricity and natural gas are substitutes for residential consumers.

The magnitude of the cross price elasticity is also small in this case. The estimates for income and population are positive and significant in the current period but insignificant in the lagged period. The elasticity for population (1.17) is large relative to the other estimates, which indicates population change has a strong effect on demand in this market.

The adjusted R-squared for this model is again very high—approximately 0.96. The fixed effects included in the model also have considerable explanatory power for this market.

We tested for first-order autocorrelation and found that it may be present in the error term. The estimate of ρ was -0.342 with a t-statistic of -6.75. Based on this result, we estimated the model assuming an AR(1) structure in the error term, which should correct the standard errors. However, autocorrelation still affects consistency of the estimate on the lagged demand term.

Regional-Level Results

This section shows regional level results for the residential electricity, commercial electricity, and residential natural gas markets. In the regional level regressions, we estimate the model using panel data from the 48 contiguous states. We estimate the following model for these regressions:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + (r_i \times Q^D_{i,t-1})\,\gamma'_Q + (r_i \times \ln \text{elec price}_{i,t})\,\beta'_P + (r_i \times \ln \text{income}_{i,t})\,\beta'_I + s_i + y_t + \varepsilon_{i,t}$$

where $Q^D_{i,t}$ is log energy demand in state *i* and year *t*, $Q^D_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g. energy prices, population, income, and climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The interaction terms interact a region indicator variable with lagged quantity, current prices, and current income. The corresponding region-specific coefficient estimates are $(\gamma + \gamma'_Q)$ for lagged quantity, $(\beta_P + \beta'_P)$ for prices, and $(\beta_I + \beta'_I)$ for income. The s_i term is a state-fixed effect estimated with an indicator variable. The y_t term is year-fixed effect also estimated with an indicator variable and $\varepsilon_{i,t}$ is a random error term.

Residential Electricity

The table shows that demand response in the South Atlantic and East South Central is most elastic and the East North Central has the most inelastic demand response. All of the estimates are negative and statistically significant, except the East North Central. The estimates also indicate regional differences in electricity demand. The estimates for the South Atlantic and East South Central have statistically significant differences from the East North Central. A Wald Test on the South Atlantic and East North Central coefficients rejects the null hypothesis that they are equal ($F(1,1130) = 14.59$; $p = 0.0001$). A Wald Test on the East South Central and East North Central coefficients also rejects that they are equal (F(1,1130) = 10.37; p=0.0013). Overall, the regression results show clear statistically significant differences in price elasticities between the regions.

Table D.4: Estimated short-run price elasticities for the residential electricity market

Short run price elasticity

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
South Atlantic	-0.318	0.047	-6.77	0	-0.41	-0.226
East South Central	-0.266	0.071	-3.74	0	-0.405	-0.126
Mid Atlantic	-0.232	0.069	-3.36	0.001	-0.368	-0.096
Mountain	-0.211	0.038	-5.55	0	-0.285	-0.136
New England	-0.192	0.046	-4.2	0	-0.281	-0.102
Pacific Coast	-0.188	0.051	-3.69	0	-0.288	-0.088
West North Central	-0.163	0.054	-3.02	0.003	-0.269	-0.057
West South Central	-0.127	0.051	-2.52	0.012	-0.227	-0.028
East North Central	-0.054	0.053	-1.01	0.312	-0.158	0.051

We tested for first-order autocorrelation in the error term and the estimate of ρ was -0.003 with a t-statistic of -0.26. The estimate indicates that first-order autocorrelation does not affect the error term and this model. Therefore, autocorrelation does not affect the estimate of lagged demand and the inference based on the standard errors is valid.

Table D.5: Estimated long-run price elasticities for the residential electricity market

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
East South Central	-0.618	0.144	-4.3	0	-0.900	-0.336
South Atlantic	-0.352	0.051	-6.86	0	-0.453	-0.251
New England	-0.325	0.074	-4.37	0	-0.471	-0.179
Mountain	-0.267	0.048	-5.52	0	-0.362	-0.172
Pacific Coast	-0.254	0.078	-3.27	0.001	-0.407	-0.101
Mid Atlantic	-0.247	0.075	-3.28	0.001	-0.395	-0.099
West North Central	-0.244	0.081	-3.01	0.003	-0.403	-0.085
West South Central	-0.174	0.070	-2.48	0.013	-0.311	-0.036
East North Central	-0.058	0.057	-1.02	0.309	-0.169	0.054

Long run price elasticities are calculated by dividing the coefficient estimate on current electricity prices by 1 – the coefficient of lagged quantity. The long-run elasticities are larger for all of the regions, which is expected and follows the general findings from previous research. The pattern of results is also similar to the short-run elasticity results. The East South Central and South Atlantic regions have the most elastic demand and the East North Central is the most inelastic. Again, all of the estimates have the expected sign and significant, except for the East North Central.

Commercial Electricity

We used the same regression model to estimate the regional-level commercial electricity market.

Table D.6: Short-run price elasticities for commercial electricity with and without Tennessee

Short-Run Price Elasticity – with Tennessee

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
East South Central	-0.759	0.322	-2.36	0.019	-1.391	-0.127
Pacific Coast	-0.364	0.099	-3.67	0	-0.559	-0.169
New England	-0.273	0.101	-2.71	0.007	-0.470	-0.076
Mountain	-0.258	0.126	-2.04	0.042	-0.505	-0.010
West South Central	-0.250	0.114	-2.19	0.029	-0.475	-0.026
East North Central	-0.237	0.111	-2.13	0.033	-0.455	-0.019
West North Central	-0.233	0.132	-1.76	0.078	-0.491	0.026
South Atlantic	-0.226	0.106	-2.13	0.034	-0.435	-0.017
Mid Atlantic	-0.215	0.081	-2.64	0.009	-0.374	-0.055

Short-Run Price Elasticity – without Tennessee

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	-0.306	0.076	-4.04	0	-0.455	-0.158
East South Central	-0.271	0.120	-2.25	0.024	-0.507	-0.035
New England	-0.212	0.079	-2.69	0.007	-0.367	-0.057
East North Central	-0.181	0.089	-2.04	0.042	-0.356	-0.007
Mid Atlantic	-0.180	0.058	-3.11	0.002	-0.293	-0.066
West South Central	-0.179	0.084	-2.12	0.034	-0.345	-0.014
Mountain	-0.178	0.102	-1.74	0.082	-0.377	0.022
West North Central	-0.166	0.109	-1.52	0.128	-0.380	0.048
South Atlantic	-0.158	0.082	-1.94	0.053	-0.318	0.002

The table shows that the data from Tennessee affect all of the results, especially the East South Central region. The EIA appears to have an error in this data series. In 2001, Tennessee's commercial electricity output doubles and then returns to previous levels in 2002. Due to this apparent error, we excluded Tennessee from the national-level results.

The estimates in the without Tennessee case are similar to the residential electric market except no region is markedly lower than the others. With a much closer range of estimates, none of these regional estimates have statistically significant differences between them. However, most are significantly different from zero (six out of nine). Overall, the estimates suggest that price elasticities vary between regions but the magnitude of the differences is not very large. In addition, the differences are difficult to detect with a sample of this size.

We tested for first-order autocorrelation in the models including and excluding Tennessee. In the model including Tennessee, the estimate of ρ was 0.071 with a t-statistic of 1.18. In the model excluding Tennessee, the estimate of ρ was 0.078 with a t-statistic of 1.26. These estimates suggest first-order autocorrelation was not a problem in either model.

Table D.7: Long-run price elasticity estimates for commercial electricity

Long-Run Price Elasticity – with Tennessee

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
East South Central	-3.106	1.595	-1.95	0.052	-6.236	0.025
Mid Atlantic	-1.737	1.598	-1.09	0.277	-4.872	1.398
Pacific Coast	-1.578	1.018	-1.55	0.121	-3.576	0.419
New England	-1.519	1.118	-1.36	0.175	-3.713	0.676
South Atlantic	-1.508	0.745	-2.02	0.043	-2.969	-0.046
East North Central	-1.156	0.644	-1.8	0.073	-2.419	0.107
Mountain	-0.901	0.448	-2.01	0.044	-1.781	-0.022
West North Central	-0.830	0.573	-1.45	0.148	-1.955	0.294
West South Central	-0.497	0.269	-1.85	0.065	-1.025	0.031

Long-Run Price Elasticity – without Tennessee

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Mid Atlantic	-1.422	1.149	-1.24	0.216	-3.677	0.832
Pacific Coast	-1.365	0.864	-1.58	0.114	-3.060	0.330
New England	-1.254	0.988	-1.27	0.205	-3.193	0.686
South Atlantic	-1.140	0.604	-1.89	0.059	-2.326	0.045
East South Central	-0.995	0.524	-1.9	0.058	-2.024	0.033
East North Central	-0.882	0.502	-1.76	0.079	-1.866	0.103
Mountain	-0.626	0.351	-1.78	0.075	-1.315	0.063
West North Central	-0.589	0.459	-1.28	0.2	-1.489	0.311
West South Central	-0.371	0.208	-1.78	0.075	-0.779	0.038

The long-run estimates are considerably larger in absolute magnitude than the short-run estimates and also larger than the residential electricity long-run estimates. Comparison between the two models shows that including Tennessee increases the magnitude of the estimates, especially for the East South Central region. When excluding this state, the magnitudes of the estimates drop, but no estimate is statistically significant from zero. The confidence intervals show that the variance of the estimates is large and they lack precision.

Residential Natural Gas

Tables D.8 and D.9 compare short-run and long-run elasticity estimates for regressions that include and exclude the state of Maine. Maine sells very low volumes of natural gas and small changes in the market can have large relative effects. It appears that the elasticity estimate is considerably larger in Maine for this reason and comparison across the tables shows that including this state has a substantial effect on the results.

Table D.8: Short run price elasticity for natural gas

Short-Run Price Elasticity – with Maine

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
New England	-0.336	0.064	-5.28	0	-0.461	-0.211
Mid Atlantic	-0.227	0.094	-2.4	0.016	-0.412	-0.042
Pacific Coast	-0.184	0.072	-2.55	0.011	-0.325	-0.043
Mountain	-0.183	0.050	-3.63	0	-0.282	-0.084
West North Central	-0.170	0.053	-3.24	0.001	-0.273	-0.067
East North Central	-0.155	0.062	-2.49	0.013	-0.277	-0.033
East South Central	-0.142	0.071	-2.01	0.045	-0.281	-0.003
South Atlantic	-0.114	0.057	-2	0.046	-0.225	-0.002
West South Central	-0.078	0.068	-1.13	0.258	-0.212	0.057

Short-Run Price Elasticity – without Maine

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Mid Atlantic	-0.174	0.081	-2.15	0.032	-0.332	-0.015
Mountain	-0.164	0.043	-3.85	0	-0.248	-0.080
Pacific Coast	-0.163	0.062	-2.63	0.009	-0.285	-0.042
West North Central	-0.138	0.044	-3.11	0.002	-0.226	-0.051
New England	-0.127	0.064	-1.98	0.048	-0.253	-0.001
East North Central	-0.120	0.053	-2.26	0.024	-0.225	-0.016
East South Central	-0.100	0.061	-1.64	0.101	-0.219	0.019
South Atlantic	-0.073	0.048	-1.5	0.133	-0.168	0.022
West South Central	-0.049	0.059	-0.84	0.4	-0.165	0.066

Table D.9: Short run price elasticity for natural gas

Long-Run Price Elasticity – with Maine

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	-0.630	0.261	-2.41	0.016	-1.142	-0.118
New England	-0.593	0.115	-5.15	0	-0.819	-0.367
Mid Atlantic	-0.469	0.192	-2.44	0.015	-0.847	-0.091
Mountain	-0.440	0.123	-3.57	0	-0.681	-0.198
East South Central	-0.396	0.222	-1.78	0.075	-0.833	0.040
West North Central	-0.298	0.093	-3.19	0.001	-0.481	-0.115
South Atlantic	-0.241	0.122	-1.96	0.05	-0.481	0.000
East North Central	-0.232	0.098	-2.37	0.018	-0.423	-0.040
West South Central	-0.126	0.114	-1.1	0.27	-0.350	0.098

Long-Run Price Elasticity – without Maine

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	-0.452	0.173	-2.61	0.009	-0.791	-0.112
Mountain	-0.355	0.092	-3.84	0	-0.536	-0.174
Mid Atlantic	-0.338	0.153	-2.2	0.028	-0.638	-0.037
New England	-0.305	0.158	-1.93	0.054	-0.614	0.005
East South Central	-0.247	0.161	-1.54	0.125	-0.562	0.068
West North Central	-0.220	0.071	-3.11	0.002	-0.358	-0.081
East North Central	-0.171	0.078	-2.19	0.029	-0.323	-0.018
South Atlantic	-0.141	0.095	-1.49	0.136	-0.327	0.045
West South Central	-0.071	0.085	-0.83	0.406	-0.239	0.097

The results show that including Maine in the analysis increases the absolute magnitude of all the elasticity estimates, especially the New England region. Since it is a tiny market compared to the other states, we will focus on the results excluding this state and have also excluded Maine in the other regressions for this market.

The residential natural gas estimates are all negative, as expected, but smaller in absolute magnitude than the electricity markets. Fewer regions are statistically significant also. Five regions are significant for both the short-run and long-run estimates.

The tests for first-order autocorrelation in the error term suggest autocorrelation exists in both models. In the model including Maine, the estimate of ρ was -0.195 with a t-statistic of -3.11. In the model excluding Maine, the estimate of ρ was -0.369 with a t-statistic of -6.75. In response to these findings, we estimated the results presented above assuming an AR(1) structure in the error terms.

State-Level Results

This section shows state-level regression results for the residential electricity, commercial electricity, and residential natural gas markets. The state-level regression is similar to the region-level model except the interaction terms are at the state level. We estimate the following model for these regressions:

$$Q^D_{i,t} = Q^D_{i,t-1}\gamma + X_{i,t}\beta + X_{i,t-1}\alpha + (s_i \text{ x } Q^D_{i,t-1})\, \gamma'_Q + (s_i \text{ x ln elec price}_{i,t})\, \beta'_P + (s_i \text{ x ln income}_{i,t})\, \beta'_I + s_i + y_t + \varepsilon_{i,t}$$

where $Q^D_{i,t}$ is log energy demand in state *i* and year *t*, $Q^D_{i,t}$ is the lag value of log energy demand, $X_{i,t}$ is a set of measured covariates (e.g. energy prices, population, income, and climate) that affect energy demand, and $X_{i,t-1}$ is the lag values of the covariates. The interaction terms interact a state indicator variable with lagged quantity, current prices, and current income. The corresponding state-specific coefficient estimates are $(\gamma + \gamma'_Q)$ for lagged quantity, $(\beta_P + \beta'_P)$ for prices, and $(\beta_I + \beta'_I)$ for income. The s_i term is a state-fixed effect estimated with an indicator variable. The y_t term is year-fixed effect also estimated with an indicator variable and $\varepsilon_{i,t}$ is a random error term.

Residential Electricity

Table D.10: State-level results for short-run price elasticity.

Short run price elasticity

	Region	Coeff	Std. Error	T-stat	P-value	95% Conf Interval	
Delaware	SA	-1.026	0.106	-9.71	0	-1.234	-0.819
Arkansas	WSC	-0.618	0.137	-4.51	0	-0.886	-0.349
Tennessee	ESC	-0.352	0.137	-2.58	0.01	-0.621	-0.084
Georgia	SA	-0.352	0.158	-2.22	0.026	-0.662	-0.041
New Hampshire	NE	-0.347	0.086	-4.05	0	-0.516	-0.179
California	PC	-0.322	0.101	-3.17	0.002	-0.521	-0.123
Missouri	WNC	-0.296	0.118	-2.51	0.012	-0.527	-0.065
Maine	NE	-0.275	0.076	-3.61	0	-0.425	-0.126
Oregon	PC	-0.258	0.100	-2.57	0.01	-0.455	-0.061
New Jersey	MA	-0.231	0.094	-2.47	0.014	-0.415	-0.047
Florida	SA	-0.218	0.092	-2.38	0.017	-0.398	-0.039
Michigan	ENC	-0.206	0.298	-0.69	0.489	-0.791	0.378
Mississippi	ESC	-0.204	0.146	-1.4	0.162	-0.490	0.082
Alabama	ESC	-0.190	0.110	-1.72	0.086	-0.407	0.027
Pennsylvania	MA	-0.151	0.101	-1.49	0.138	-0.349	0.048
Virginia	SA	-0.148	0.174	-0.85	0.398	-0.490	0.195
South Dakota	WNC	-0.141	0.123	-1.15	0.25	-0.382	0.099
Ohio	ENC	-0.135	0.140	-0.97	0.333	-0.410	0.139
New York	MA	-0.125	0.119	-1.06	0.291	-0.358	0.107

North Carolina	SA	-0.113	0.115	-0.98	0.326	-0.340	0.113
Massachusetts	NE	-0.108	0.105	-1.03	0.304	-0.315	0.098
Rhode Island	NE	-0.103	0.092	-1.12	0.262	-0.283	0.077
Illinois	ENC	-0.090	0.070	-1.3	0.195	-0.227	0.046
Connecticut	NE	-0.090	0.077	-1.17	0.243	-0.240	0.061
Washington	PC	-0.079	0.061	-1.3	0.195	-0.199	0.041
Iowa	WNC	-0.074	0.128	-0.58	0.562	-0.324	0.176
Texas	WSC	-0.062	0.077	-0.81	0.419	-0.213	0.089
Arizona	M	-0.059	0.094	-0.63	0.532	-0.243	0.125
Montana	M	-0.056	0.119	-0.47	0.637	-0.289	0.177
Indiana	ENC	-0.054	0.094	-0.58	0.564	-0.239	0.130
North Dakota	WNC	-0.046	0.093	-0.49	0.624	-0.229	0.137
Oklahoma	WSC	-0.004	0.080	-0.06	0.956	-0.161	0.152
Louisiana	WSC	0.048	0.071	0.68	0.497	-0.091	0.187
New Mexico	M	0.049	0.099	0.49	0.622	-0.145	0.242
West Virginia	SA	0.052	0.177	0.29	0.769	-0.295	0.398
Nevada	M	0.057	0.073	0.79	0.431	-0.085	0.200
Kentucky	ESC	0.082	0.110	0.75	0.453	-0.133	0.297
South Carolina	SA	0.084	0.100	0.84	0.402	-0.113	0.281
Idaho	M	0.089	0.087	1.02	0.308	-0.082	0.261
Vermont	NE	0.109	0.208	0.52	0.602	-0.300	0.517
Utah	M	0.120	0.073	1.64	0.102	-0.024	0.264
Kansas	WNC	0.128	0.077	1.66	0.097	-0.023	0.280
Maryland	SA	0.136	0.171	0.8	0.427	-0.199	0.471
Minnesota	WNC	0.140	0.134	1.05	0.294	-0.122	0.402
Wisconsin	ENC	0.154	0.085	1.81	0.071	-0.013	0.321
Nebraska	WNC	0.178	0.123	1.46	0.146	-0.062	0.419
Wyoming	M	0.219	0.097	2.27	0.023	0.030	0.409
Colorado	M	0.599	0.129	4.64	0	0.345	0.852

The results show a wide range in estimates at the state level. Most estimates have the expected negative sign, but eleven states are in the positive range. Most of the positive estimates are near zero and their confidence intervals include the negative range. Wyoming and Colorado are significant, positive, and relatively large in absolute magnitude. Delaware and Arkansas have the largest magnitudes in the negative range. Between these two ends of the range, thirty states have negative elasticities in the range seen in the national- and regional-level results (near 0 to -0.3). In this range, the confidence interval for most states includes the national-level estimate (-0.24).

The states with elasticities in the extreme parts of the range indicate a possible omitted variable. Colorado experienced a sharp growth in electricity demand in the early 1980's, which was coincident with a period of rising prices. This short increase is unexplained by other regressors in the model. Houthakker et. al. (1974) noticed a correlation between rural states and low/positive elasticities. The same pattern occurs in these results. Nearly all the states with positive elasticities are predominantly rural.

Table D.11: Long Run Price Elasticity

	Region	Coeff	Std. Error	T-stat	P-value	95% Conf	Interval
Delaware	SA	-0.999	0.093	-10.73	0	-1.182	-0.816
Arkansas	WSC	-0.539	0.069	-7.8	0	-0.675	-0.404
California	PC	-0.492	0.273	-1.8	0.072	-1.027	0.044
New Hampshire	NE	-0.470	0.127	-3.69	0	-0.720	-0.220
Maine	NE	-0.437	0.144	-3.03	0.002	-0.720	-0.154
Tennessee	ESC	-0.401	0.131	-3.07	0.002	-0.658	-0.145
Georgia	SA	-0.313	0.114	-2.75	0.006	-0.536	-0.090
Missouri	WNC	-0.263	0.092	-2.86	0.004	-0.444	-0.083
Florida	SA	-0.244	0.085	-2.87	0.004	-0.411	-0.077
Michigan	ENC	-0.244	0.310	-0.79	0.432	-0.853	0.365
New Jersey	MA	-0.240	0.100	-2.41	0.016	-0.436	-0.045
Mississippi	ESC	-0.238	0.180	-1.32	0.186	-0.591	0.115
Oregon	PC	-0.236	0.098	-2.41	0.016	-0.429	-0.044
Alabama	ESC	-0.221	0.114	-1.94	0.053	-0.444	0.003
Virginia	SA	-0.184	0.213	-0.86	0.388	-0.601	0.234
New York	MA	-0.178	0.169	-1.05	0.293	-0.509	0.154
South Dakota	WNC	-0.166	0.152	-1.09	0.277	-0.465	0.133
Rhode Island	NE	-0.164	0.162	-1.01	0.313	-0.481	0.154
Pennsylvania	MA	-0.163	0.110	-1.49	0.137	-0.379	0.052
Washington	PC	-0.161	0.149	-1.08	0.279	-0.453	0.131
Massachusetts	NE	-0.150	0.160	-0.93	0.35	-0.464	0.165
Ohio	ENC	-0.136	0.138	-0.98	0.327	-0.407	0.136
Connecticut	NE	-0.123	0.101	-1.21	0.225	-0.321	0.076
North Carolina	SA	-0.109	0.102	-1.06	0.288	-0.310	0.092
Iowa	WNC	-0.092	0.161	-0.57	0.568	-0.408	0.224
Texas	WSC	-0.081	0.100	-0.81	0.418	-0.276	0.115
Montana	M	-0.079	0.174	-0.46	0.648	-0.420	0.261
Illinois	ENC	-0.076	0.052	-1.46	0.145	-0.179	0.026
Arizona	M	-0.066	0.104	-0.63	0.528	-0.270	0.138
Indiana	ENC	-0.056	0.095	-0.59	0.557	-0.243	0.131
North Dakota	WNC	-0.055	0.113	-0.49	0.625	-0.277	0.167
Oklahoma	WSC	-0.005	0.094	-0.06	0.956	-0.190	0.179
Nevada	M	0.046	0.057	0.81	0.418	-0.066	0.158
West Virginia	SA	0.053	0.179	0.29	0.769	-0.299	0.404
New Mexico	M	0.059	0.119	0.5	0.62	-0.175	0.293
Louisiana	WSC	0.060	0.086	0.7	0.486	-0.108	0.228
South Carolina	SA	0.089	0.106	0.84	0.401	-0.119	0.297
Idaho	M	0.106	0.104	1.02	0.309	-0.098	0.310
Utah	M	0.123	0.075	1.64	0.102	-0.025	0.271
Kentucky	ESC	0.134	0.174	0.77	0.441	-0.207	0.475
Kansas	WNC	0.143	0.084	1.71	0.088	-0.021	0.307
Minnesota	WNC	0.202	0.196	1.03	0.303	-0.183	0.586
Nebraska	WNC	0.206	0.135	1.52	0.129	-0.060	0.471
Maryland	SA	0.206	0.255	0.81	0.419	-0.294	0.706

Vermont	NE	0.281	0.580	0.48	0.629	-0.857	1.419
Wyoming	M	0.296	0.127	2.33	0.02	0.047	0.545
Wisconsin	ENC	0.302	0.183	1.65	0.099	-0.057	0.661
Colorado	M	0.666	0.105	6.36	0	0.461	0.872

The long run elasticity estimates show greater variability. Only 12 states have statistically significant estimates and two of those are positive. Similar to the other markets, long run price elasticities are generally greater than the short run estimates.

We tested for first-order autocorrelation in the state-level residential electricity model and found it does not appear to affect the error term. The estimate of ρ was -0.004 with a t-statistic of -0.89. The results indicate that autocorrelation does not affect consistency of estimates on the lagged demand term and that inference based on the existing standard errors is valid.

Commercial Electricity

Table D.12: Short-run elasticity estimates for commercial electricity

Short Run Commercial Electricity

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Tennessee	-3.363	2.314	-1.45	0.147	-7.90	1.18
Maryland	-1.086	0.946	-1.15	0.251	-2.94	0.77
Nevada	-1.016	0.668	-1.52	0.129	-2.33	0.30
Michigan	-0.948	0.583	-1.63	0.105	-2.09	0.20
Vermont	-0.805	0.212	-3.79	0	-1.22	-0.39
Alabama	-0.656	0.288	-2.28	0.023	-1.22	-0.09
South Carolina	-0.506	0.195	-2.59	0.01	-0.89	-0.12
Oregon	-0.477	0.103	-4.62	0	-0.68	-0.27
Illinois	-0.450	0.144	-3.13	0.002	-0.73	-0.17
Montana	-0.425	0.515	-0.83	0.409	-1.44	0.59
Rhode Island	-0.400	0.107	-3.75	0	-0.61	-0.19
Idaho	-0.337	0.282	-1.2	0.232	-0.89	0.22
Washington	-0.326	0.255	-1.28	0.201	-0.83	0.17
Massachusetts	-0.311	0.099	-3.15	0.002	-0.50	-0.12
New Jersey	-0.310	0.109	-2.85	0.004	-0.52	-0.10
Iowa	-0.309	0.183	-1.69	0.092	-0.67	0.05
Maine	-0.307	0.106	-2.9	0.004	-0.52	-0.10
Texas	-0.281	0.112	-2.51	0.012	-0.50	-0.06
Arizona	-0.246	0.193	-1.27	0.203	-0.63	0.13
Kansas	-0.237	0.113	-2.1	0.036	-0.46	-0.02
Ohio	-0.220	0.215	-1.02	0.306	-0.64	0.20
California	-0.201	0.123	-1.63	0.104	-0.44	0.04
Connecticut	-0.192	0.114	-1.69	0.092	-0.42	0.03

Virginia	-0.192	0.138	-1.39	0.164	-0.46	0.08
Delaware	-0.186	0.163	-1.14	0.256	-0.51	0.14
New Mexico	-0.183	0.158	-1.16	0.246	-0.49	0.13
Minnesota	-0.173	0.183	-0.95	0.344	-0.53	0.19
Mississippi	-0.165	0.224	-0.74	0.462	-0.60	0.27
West Virginia	-0.155	0.120	-1.29	0.197	-0.39	0.08
Utah	-0.152	0.140	-1.08	0.279	-0.43	0.12
New York	-0.150	0.086	-1.75	0.081	-0.32	0.02
Oklahoma	-0.108	0.153	-0.7	0.482	-0.41	0.19
Arkansas	-0.108	0.153	-0.7	0.481	-0.41	0.19
Louisiana	-0.098	0.119	-0.83	0.408	-0.33	0.13
Pennsylvania	-0.091	0.073	-1.24	0.216	-0.23	0.05
Florida	-0.070	0.121	-0.58	0.561	-0.31	0.17
North Dakota	-0.055	0.453	-0.12	0.903	-0.94	0.83
Kentucky	-0.053	0.122	-0.44	0.664	-0.29	0.19
Wisconsin	-0.033	0.199	-0.17	0.868	-0.42	0.36
North Carolina	-0.028	0.106	-0.26	0.793	-0.24	0.18
Missouri	-0.022	0.136	-0.16	0.872	-0.29	0.25
Colorado	0.016	0.140	0.12	0.907	-0.26	0.29
Wyoming	0.042	0.132	0.32	0.749	-0.22	0.30
Indiana	0.102	0.174	0.59	0.556	-0.24	0.44
New Hampshire	0.146	0.341	0.43	0.669	-0.52	0.81
Nebraska	0.172	0.157	1.1	0.273	-0.14	0.48
Georgia	0.219	0.117	1.88	0.061	-0.01	0.45
South Dakota	0.335	0.581	0.58	0.564	-0.80	1.48

The state-level estimates lack precision. In comparison to the residential data, the commercial electricity quantity data have much greater variability, which results in less precise estimates for price elasticity. As a result, only nine states have statistically significant results. A data error appears to cause the large estimate for Tennessee. This data problem was discussed in the regional level section.

The estimates are distributed more evenly throughout the range compared to residential electricity. There are also fewer positive estimates and none of the positive estimates are significant.

Table D.13: Long Run Commercial Electricity Elasticity Estimates

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Tennessee	-10.338	4.001	-2.58	0.01	-18.19	-2.48
Maryland	-7.467	3.332	-2.24	0.025	-14.01	-0.93
Alabama	-4.892	4.255	-1.15	0.251	-13.24	3.46
Nevada	-1.730	0.859	-2.01	0.044	-3.42	-0.04
Michigan	-1.496	0.537	-2.79	0.005	-2.55	-0.44
Rhode Island	-1.315	1.232	-1.07	0.286	-3.73	1.10
Ohio	-1.243	1.500	-0.83	0.407	-4.19	1.70

Washington	-1.210	2.205	-0.55	0.583	-5.54	3.12
Montana	-1.177	1.349	-0.87	0.383	-3.82	1.47
Massachusetts	-1.010	0.719	-1.4	0.161	-2.42	0.40
Vermont	-0.899	0.318	-2.83	0.005	-1.52	-0.28
Illinois	-0.804	0.248	-3.24	0.001	-1.29	-0.32
New Jersey	-0.740	0.431	-1.72	0.086	-1.59	0.11
Oregon	-0.678	0.497	-1.36	0.173	-1.65	0.30
South Carolina	-0.623	0.146	-4.28	0	-0.91	-0.34
Connecticut	-0.516	0.540	-0.96	0.34	-1.57	0.54
Delaware	-0.514	0.622	-0.83	0.409	-1.73	0.71
Iowa	-0.493	0.276	-1.79	0.074	-1.04	0.05
West Virginia	-0.489	0.401	-1.22	0.223	-1.28	0.30
Pennsylvania	-0.412	0.493	-0.84	0.404	-1.38	0.56
Minnesota	-0.396	0.459	-0.86	0.389	-1.30	0.51
Utah	-0.394	0.474	-0.83	0.406	-1.32	0.54
Texas	-0.384	0.158	-2.44	0.015	-0.69	-0.07
Mississippi	-0.379	0.550	-0.69	0.491	-1.46	0.70
New Mexico	-0.372	0.468	-0.79	0.428	-1.29	0.55
Kansas	-0.371	0.277	-1.34	0.182	-0.91	0.17
Idaho	-0.366	0.381	-0.96	0.337	-1.11	0.38
Virginia	-0.365	0.297	-1.23	0.22	-0.95	0.22
Maine	-0.348	0.154	-2.26	0.024	-0.65	-0.05
Arizona	-0.330	0.258	-1.28	0.201	-0.84	0.18
California	-0.301	0.266	-1.13	0.259	-0.82	0.22
New York	-0.297	0.257	-1.15	0.249	-0.80	0.21
Oklahoma	-0.147	0.227	-0.65	0.516	-0.59	0.30
North Dakota	-0.145	1.248	-0.12	0.908	-2.59	2.30
Arkansas	-0.132	0.215	-0.62	0.539	-0.55	0.29
Louisiana	-0.130	0.172	-0.76	0.449	-0.47	0.21
Florida	-0.118	0.201	-0.59	0.558	-0.51	0.28
Kentucky	-0.080	0.212	-0.38	0.707	-0.50	0.34
North Carolina	-0.066	0.265	-0.25	0.802	-0.59	0.45
Missouri	-0.057	0.366	-0.16	0.875	-0.78	0.66
Wisconsin	-0.034	0.208	-0.16	0.871	-0.44	0.37
Colorado	0.038	0.325	0.12	0.907	-0.60	0.68
Wyoming	0.153	0.470	0.33	0.745	-0.77	1.08
New Hampshire	0.306	0.579	0.53	0.597	-0.83	1.44
Georgia	0.327	0.173	1.89	0.059	-0.01	0.67
Indiana	0.353	0.651	0.54	0.587	-0.92	1.63
South Dakota	0.434	0.651	0.67	0.505	-0.84	1.71
Nebraska	0.441	0.354	1.25	0.213	-0.25	1.14

The long run commercial electricity estimates appear sensitive to the model specification. Given this model, when the coefficient of lagged quantity nears one, the denominator of the expression decreases and the estimate can become very large. This occurs in the first three states on the list: Tennessee, Maryland, and Alabama.

The remaining estimates are generally larger than the short run estimates. The states also remain in relatively similar positions to the short run estimates.

We tested for first-order autocorrelation in the state-level commercial electricity model and found it does not appear to affect the error term. The estimate of ρ was 0.018 with a t-statistic of 0.50. The results indicate that autocorrelation does not affect consistency of estimates on the lagged demand term and that inference based on the existing standard errors is valid.

Natural Gas

Table D.14: Regression results for short run residential natural gas elasticity.

Short Run Natural Gas

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Maine	-0.745	0.467	-1.59	0.111	-1.662	0.172
Vermont	-0.281	0.084	-3.35	0.001	-0.445	-0.117
Illinois	-0.229	0.084	-2.72	0.007	-0.394	-0.064
New Hampshire	-0.225	0.093	-2.41	0.016	-0.408	-0.042
Montana	-0.217	0.079	-2.75	0.006	-0.372	-0.062
South Carolina	-0.202	0.141	-1.43	0.154	-0.479	0.076
New Mexico	-0.190	0.111	-1.71	0.088	-0.408	0.028
Virginia	-0.189	0.104	-1.81	0.07	-0.393	0.015
West Virginia	-0.184	0.083	-2.22	0.027	-0.347	-0.021
North Dakota	-0.183	0.063	-2.88	0.004	-0.308	-0.059
Alabama	-0.170	0.103	-1.64	0.101	-0.372	0.033
Kansas	-0.167	0.071	-2.37	0.018	-0.305	-0.028
Washington	-0.166	0.109	-1.53	0.125	-0.380	0.047
Arkansas	-0.151	0.080	-1.89	0.059	-0.308	0.006
North Carolina	-0.149	0.102	-1.46	0.145	-0.350	0.052
Missouri	-0.143	0.068	-2.11	0.035	-0.276	-0.010
Indiana	-0.139	0.063	-2.21	0.027	-0.263	-0.015
Kentucky	-0.137	0.059	-2.31	0.021	-0.253	-0.021
Ohio	-0.127	0.076	-1.68	0.093	-0.276	0.021
Pennsylvania	-0.117	0.089	-1.31	0.19	-0.291	0.058
South Dakota	-0.112	0.077	-1.46	0.144	-0.263	0.039
Tennessee	-0.110	0.101	-1.09	0.277	-0.308	0.088
Maryland	-0.106	0.109	-0.97	0.331	-0.319	0.108
Colorado	-0.102	0.069	-1.48	0.14	-0.237	0.033
Minnesota	-0.100	0.066	-1.52	0.129	-0.229	0.029
California	-0.098	0.119	-0.82	0.41	-0.332	0.135
Iowa	-0.098	0.090	-1.09	0.278	-0.275	0.079
Wisconsin	-0.098	0.066	-1.49	0.138	-0.227	0.031
Rhode Island	-0.085	0.122	-0.7	0.485	-0.323	0.154
Idaho	-0.074	0.076	-0.98	0.329	-0.223	0.075
Mississippi	-0.061	0.080	-0.76	0.448	-0.217	0.096
Michigan	-0.047	0.083	-0.57	0.57	-0.209	0.115

Utah	-0.031	0.108	-0.29	0.771	-0.244	0.181
Connecticut	-0.029	0.128	-0.23	0.819	-0.281	0.222
Delaware	-0.024	0.102	-0.24	0.812	-0.224	0.175
Oregon	-0.024	0.088	-0.27	0.786	-0.198	0.149
Florida	-0.016	0.255	-0.06	0.951	-0.516	0.484
Texas	-0.006	0.111	-0.05	0.958	-0.224	0.212
Massachusetts	-0.005	0.148	-0.04	0.971	-0.295	0.284
Louisiana	0.009	0.077	0.11	0.909	-0.143	0.161
Nevada	0.011	0.093	0.12	0.904	-0.172	0.195
Georgia	0.023	0.107	0.21	0.833	-0.188	0.233
New York	0.027	0.114	0.24	0.814	-0.197	0.250
Nebraska	0.034	0.073	0.46	0.642	-0.109	0.177
Oklahoma	0.050	0.107	0.47	0.641	-0.160	0.260
New Jersey	0.072	0.115	0.63	0.53	-0.153	0.297
Wyoming	0.077	0.117	0.66	0.509	-0.152	0.307
Arizona	0.086	0.150	0.57	0.566	-0.208	0.381

The short-run estimates are mostly lower in the natural gas market than the electricity markets, with the exception of Maine which was discussed earlier. The overall precision of the estimates is also limited, which is shown by only ten states with statistically significant results. The natural gas market, like the commercial electricity market, had much greater variability in demand. Therefore, the limited precision is not surprising.

Table D.15: Regression results for long-run price elasticities for residential natural gas

Long Run Natural Gas

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Maine	-1.826	0.891	-2.05	0.041	-3.575	-0.078
Vermont	-0.577	0.189	-3.06	0.002	-0.947	-0.207
New Hampshire	-0.430	0.232	-1.86	0.064	-0.885	0.024
Virginia	-0.322	0.179	-1.8	0.072	-0.672	0.028
South Carolina	-0.299	0.248	-1.2	0.228	-0.787	0.188
Montana	-0.287	0.101	-2.83	0.005	-0.486	-0.088
New Mexico	-0.281	0.144	-1.96	0.05	-0.563	0.000
North Carolina	-0.279	0.212	-1.32	0.187	-0.695	0.136
West Virginia	-0.270	0.129	-2.1	0.036	-0.523	-0.018
Illinois	-0.243	0.100	-2.44	0.015	-0.438	-0.047
North Dakota	-0.230	0.087	-2.64	0.009	-0.402	-0.059
Washington	-0.214	0.147	-1.45	0.147	-0.503	0.075
Missouri	-0.174	0.081	-2.16	0.031	-0.332	-0.016
Kentucky	-0.171	0.073	-2.34	0.02	-0.315	-0.028
Kansas	-0.168	0.072	-2.34	0.019	-0.310	-0.027
Tennessee	-0.167	0.169	-0.99	0.323	-0.498	0.165
Indiana	-0.163	0.078	-2.08	0.037	-0.317	-0.009
Rhode Island	-0.163	0.234	-0.7	0.487	-0.622	0.296
Alabama	-0.159	0.090	-1.77	0.077	-0.336	0.017

South Dakota	-0.142	0.107	-1.33	0.183	-0.352	0.067
Arkansas	-0.141	0.075	-1.87	0.062	-0.289	0.007
Maryland	-0.134	0.136	-0.99	0.323	-0.400	0.132
Minnesota	-0.133	0.088	-1.5	0.134	-0.306	0.041
California	-0.132	0.166	-0.8	0.425	-0.458	0.193
Ohio	-0.132	0.081	-1.64	0.101	-0.291	0.026
Pennsylvania	-0.124	0.098	-1.27	0.205	-0.315	0.068
Colorado	-0.122	0.075	-1.63	0.104	-0.270	0.025
Iowa	-0.114	0.109	-1.04	0.296	-0.329	0.100
Wisconsin	-0.110	0.075	-1.46	0.145	-0.257	0.038
Idaho	-0.104	0.112	-0.94	0.35	-0.323	0.115
Mississippi	-0.079	0.110	-0.72	0.471	-0.295	0.136
Michigan	-0.075	0.131	-0.57	0.567	-0.333	0.182
Utah	-0.061	0.213	-0.29	0.776	-0.478	0.357
Connecticut	-0.042	0.184	-0.23	0.818	-0.402	0.318
Delaware	-0.036	0.153	-0.24	0.813	-0.337	0.264
Oregon	-0.028	0.104	-0.27	0.788	-0.232	0.176
Florida	-0.020	0.317	-0.06	0.951	-0.642	0.603
Massachusetts	-0.009	0.256	-0.04	0.971	-0.512	0.494
Texas	-0.008	0.159	-0.05	0.958	-0.320	0.303
Louisiana	0.011	0.093	0.11	0.909	-0.171	0.193
Nevada	0.021	0.175	0.12	0.905	-0.323	0.365
Georgia	0.022	0.105	0.21	0.834	-0.185	0.229
New York	0.029	0.124	0.24	0.812	-0.213	0.272
Nebraska	0.038	0.081	0.47	0.64	-0.121	0.197
Oklahoma	0.056	0.120	0.47	0.641	-0.179	0.291
New Jersey	0.082	0.129	0.63	0.528	-0.172	0.335
Wyoming	0.092	0.127	0.73	0.465	-0.156	0.341
Arizona	0.119	0.220	0.54	0.588	-0.312	0.550

Similar to other markets, the long-run estimates are generally larger than the short run estimates. The precision of these estimates is also limited, which is shown by the large standard errors and that only ten states have statistically significant estimates. The natural gas market also had much greater variation in prices and quantity during this period, which appears to affect the results at this level of aggregation. With the exception of Maine, the range of estimates is smaller than the electricity markets, which corresponds to the generally smaller (in absolute magnitude) values of the estimates when compared to the other markets.

We tested for first-order autocorrelation in the state-level residential natural gas model and found it does not appear to affect the error term. The estimate of ρ was -0.12 with a t-statistic of -1.75. The results indicate that autocorrelation does not affect consistency of estimates on the lagged demand term and that inference based on the existing standard errors is valid.

Utility-level results

Table D.16: Short run elasticity estimates for residential electricity at the utility level

Utility Number	region	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
182	ENC	-1.563	0.472	-3.31	0.001	-2.490	-0.637
208	ENC	-1.081	0.633	-1.71	0.088	-2.323	0.160
186	ENC	-1.061	0.521	-2.04	0.042	-2.082	-0.039
191	ENC	-0.697	0.275	-2.54	0.011	-1.237	-0.158
18	ENC	-0.584	0.279	-2.1	0.036	-1.13	-0.04
75	ENC	-0.480	0.498	-0.96	0.335	-1.46	0.50
134	ENC	-0.392	0.257	-1.53	0.127	-0.896	0.112
153	ENC	-0.314	0.238	-1.32	0.188	-0.781	0.154
35	ENC	-0.250	0.160	-1.57	0.118	-0.56	0.06
73	ENC	-0.243	0.135	-1.8	0.072	-0.51	0.02
177	ENC	-0.217	0.622	-0.35	0.728	-1.438	1.004
67	ENC	-0.167	0.245	-0.68	0.495	-0.65	0.31
41	ENC	-0.150	0.353	-0.43	0.671	-0.84	0.54
44	ENC	-0.137	0.291	-0.47	0.637	-0.71	0.43
17	ENC	-0.131	0.469	-0.28	0.78	-1.05	0.79
76	ENC	-0.105	0.337	-0.31	0.756	-0.77	0.56
38	ENC	-0.097	0.427	-0.23	0.82	-0.93	0.74
26	ENC	-0.091	0.359	-0.25	0.8	-0.80	0.61
96	ENC	-0.082	0.331	-0.25	0.803	-0.73	0.57
105	ENC	-0.070	0.175	-0.4	0.689	-0.41	0.27
28	ENC	-0.045	0.399	-0.11	0.909	-0.83	0.74
33	ENC	-0.033	0.320	-0.1	0.917	-0.66	0.59
206	ENC	-0.004	0.517	-0.01	0.994	-1.019	1.011
133	ENC	0.024	0.490	0.05	0.96	-0.936	0.985
207	ENC	0.109	0.355	0.31	0.758	-0.587	0.806
129	ENC	0.211	0.563	0.37	0.708	-0.894	1.315
130	ENC	0.952	1.475	0.65	0.519	-1.941	3.845
103	ESC	-1.514	0.410	-3.69	0	-2.32	-0.71
113	ESC	-1.222	0.397	-3.08	0.002	-2.00	-0.44
47	ESC	-1.126	0.675	-1.67	0.096	-2.45	0.20
120	ESC	-1.064	0.625	-1.7	0.089	-2.291	0.163
30	ESC	-1.046	0.689	-1.52	0.129	-2.40	0.31
198	ESC	-0.958	0.414	-2.32	0.021	-1.770	-0.147
40	ESC	-0.884	0.857	-1.03	0.302	-2.56	0.80
110	ESC	-0.766	0.389	-1.97	0.049	-1.53	0.00
92	ESC	-0.680	0.598	-1.14	0.256	-1.85	0.49
86	ESC	-0.528	0.394	-1.34	0.181	-1.30	0.25
179	ESC	-0.499	0.230	-2.17	0.03	-0.950	-0.048
69	ESC	-0.486	0.592	-0.82	0.411	-1.65	0.67
98	ESC	-0.439	0.835	-0.53	0.599	-2.08	1.20
193	ESC	-0.299	0.386	-0.77	0.439	-1.055	0.458
172	ESC	-0.297	0.276	-1.07	0.283	-0.839	0.245
1	ESC	-0.200	0.522	-0.38	0.701	-1.22	0.82
23	ESC	-0.192	0.521	-0.37	0.713	-1.21	0.83

107	ESC	-0.178	0.548	-0.32	0.746	-1.25	0.90
93	ESC	-0.088	0.226	-0.39	0.699	-0.53	0.36
210	ESC	-0.018	0.801	-0.02	0.982	-1.589	1.552
57	ESC	0.148	0.745	0.2	0.843	-1.31	1.61
91	ESC	0.317	0.338	0.94	0.348	-0.35	0.98
112	ESC	0.402	0.612	0.66	0.511	-0.80	1.60
200	ESC	1.389	0.305	4.55	0	0.790	1.987
211	M	-1.206	0.394	-3.06	0.002	-1.979	-0.433
94	M	-1.084	0.629	-1.72	0.085	-2.32	0.15
140	M	-0.980	0.401	-2.45	0.015	-1.767	-0.194
155	M	-0.696	0.248	-2.81	0.005	-1.183	-0.210
171	M	-0.694	0.586	-1.18	0.237	-1.844	0.456
184	M	-0.663	0.607	-1.09	0.274	-1.854	0.527
164	M	-0.547	0.403	-1.36	0.174	-1.338	0.243
151	M	-0.368	1.027	-0.36	0.72	-2.382	1.647
53	M	-0.325	0.725	-0.45	0.655	-1.75	1.10
122	M	-0.262	0.075	-3.51	0	-0.409	-0.116
152	M	-0.260	0.396	-0.66	0.512	-1.036	0.516
32	M	-0.233	0.649	-0.36	0.72	-1.51	1.04
5	M	-0.221	0.372	-0.59	0.552	-0.95	0.51
118	M	-0.096	0.187	-0.51	0.61	-0.463	0.272
196	M	-0.061	0.305	-0.2	0.842	-0.660	0.538
25	M	-0.014	0.253	-0.06	0.955	-0.51	0.48
104	M	-0.001	0.283	0	0.996	-0.56	0.55
71	M	0.467	0.298	1.57	0.117	-0.12	1.05
202	MA	-0.800	0.429	-1.87	0.062	-1.641	0.041
109	MA	-0.792	0.625	-1.27	0.205	-2.02	0.43
37	MA	-0.712	0.600	-1.19	0.235	-1.89	0.46
100	MA	-0.639	0.418	-1.53	0.126	-1.46	0.18
160	MA	-0.417	0.383	-1.09	0.277	-1.169	0.336
125	MA	-0.345	0.321	-1.07	0.284	-0.975	0.286
147	MA	-0.341	0.284	-1.2	0.23	-0.897	0.216
145	MA	-0.308	0.477	-0.65	0.518	-1.244	0.627
213	MA	-0.230	0.301	-0.76	0.446	-0.821	0.361
85	MA	-0.177	0.364	-0.49	0.626	-0.89	0.54
157	MA	-0.117	0.475	-0.25	0.805	-1.050	0.815
49	MA	-0.089	0.240	-0.37	0.711	-0.56	0.38
161	MA	-0.003	0.492	-0.01	0.996	-0.967	0.962
16	MA	0.077	0.478	0.16	0.872	-0.86	1.02
137	MA	0.099	0.329	0.3	0.763	-0.546	0.744
146	MA	0.125	0.146	0.86	0.39	-0.161	0.412
7	MA	0.171	0.180	0.95	0.341	-0.18	0.52
144	MA	0.302	0.323	0.94	0.35	-0.332	0.936
126	MA	0.350	0.296	1.18	0.238	-0.231	0.932
20	NE	-0.722	0.421	-1.72	0.086	-1.55	0.10
119	NE	-0.596	0.569	-1.05	0.296	-1.713	0.521
65	NE	-0.546	0.149	-3.65	0	-0.84	-0.25
22	NE	-0.391	0.278	-1.41	0.159	-0.94	0.15
123	NE	-0.360	0.229	-1.57	0.117	-0.809	0.090
194	NE	-0.197	0.535	-0.37	0.712	-1.246	0.851

34	NE	-0.196	0.212	-0.93	0.355	-0.61	0.22
36	NE	-0.154	0.348	-0.44	0.659	-0.84	0.53
14	NE	-0.091	0.254	-0.36	0.721	-0.59	0.41
46	NE	-0.019	0.272	-0.07	0.946	-0.55	0.52
4	NE	0.063	0.416	0.15	0.88	-0.75	0.88
154	NE	0.072	0.723	0.1	0.92	-1.346	1.491
10	NE	0.191	0.333	0.57	0.566	-0.46	0.84
204	NE	0.197	0.400	0.49	0.622	-0.587	0.981
106	NE	0.849	0.908	0.93	0.35	-0.93	2.63
139	PC	-1.215	0.094	-12.96	0	-1.399	-1.031
24	PC	-0.961	0.035	-27.6	0	-1.03	-0.89
2	PC	-0.770	0.144	-5.35	0	-1.05	-0.49
173	PC	-0.595	0.568	-1.05	0.295	-1.711	0.520
158	PC	-0.488	0.486	-1	0.315	-1.440	0.465
101	PC	-0.471	0.269	-1.75	0.081	-1.00	0.06
64	PC	-0.444	0.324	-1.37	0.171	-1.08	0.19
166	PC	-0.430	0.366	-1.18	0.24	-1.147	0.287
176	PC	-0.279	0.365	-0.76	0.444	-0.995	0.437
39	PC	-0.219	0.228	-0.96	0.336	-0.67	0.23
188	PC	-0.156	0.379	-0.41	0.682	-0.899	0.588
27	PC	-0.119	0.431	-0.28	0.783	-0.96	0.73
142	PC	-0.119	0.335	-0.35	0.724	-0.776	0.539
170	PC	0.014	0.377	0.04	0.971	-0.726	0.754
74	PC	0.068	0.303	0.23	0.822	-0.53	0.66
163	PC	0.144	0.511	0.28	0.778	-0.859	1.147
201	PC	0.279	0.552	0.5	0.614	-0.805	1.362
11	PC	0.324	0.181	1.79	0.073	-0.03	0.68
159	PC	0.404	0.548	0.74	0.461	-0.671	1.479
115	PC	0.475	0.421	1.13	0.26	-0.35	1.30
148	PC	0.670	0.402	1.66	0.096	-0.120	1.459
52	PC	0.756	0.515	1.47	0.142	-0.25	1.77
197	SA	-1.477	0.743	-1.99	0.047	-2.935	-0.020
178	SA	-1.434	0.542	-2.65	0.008	-2.497	-0.371
29	SA	-1.299	0.474	-2.74	0.006	-2.23	-0.37
63	SA	-1.232	0.725	-1.7	0.09	-2.65	0.19
199	SA	-1.150	0.635	-1.81	0.07	-2.396	0.096
187	SA	-1.087	0.525	-2.07	0.039	-2.118	-0.056
95	SA	-1.073	0.621	-1.73	0.085	-2.29	0.15
31	SA	-1.038	0.238	-4.36	0	-1.50	-0.57
97	SA	-1.032	0.621	-1.66	0.097	-2.25	0.19
127	SA	-0.890	0.660	-1.35	0.178	-2.186	0.405
169	SA	-0.884	0.366	-2.42	0.016	-1.602	-0.167
84	SA	-0.878	0.566	-1.55	0.121	-1.99	0.23
168	SA	-0.854	0.290	-2.94	0.003	-1.423	-0.284
189	SA	-0.827	0.607	-1.36	0.173	-2.018	0.363
83	SA	-0.814	0.306	-2.66	0.008	-1.41	-0.21
15	SA	-0.734	0.583	-1.26	0.208	-1.88	0.41
128	SA	-0.686	0.297	-2.31	0.021	-1.270	-0.103
60	SA	-0.678	0.368	-1.84	0.066	-1.40	0.05
48	SA	-0.542	0.673	-0.8	0.421	-1.86	0.78

72	SA	-0.540	0.504	-1.07	0.284	-1.53	0.45
116	SA	-0.472	0.298	-1.58	0.113	-1.06	0.11
190	SA	-0.458	0.501	-0.91	0.361	-1.441	0.525
62	SA	-0.447	0.320	-1.4	0.162	-1.07	0.18
174	SA	-0.438	0.541	-0.81	0.418	-1.498	0.623
66	SA	-0.304	0.334	-0.91	0.363	-0.96	0.35
58	SA	-0.299	0.373	-0.8	0.422	-1.03	0.43
56	SA	-0.272	0.366	-0.74	0.458	-0.99	0.45
82	SA	-0.243	0.354	-0.69	0.492	-0.94	0.45
54	SA	-0.195	0.388	-0.5	0.614	-0.96	0.57
141	SA	-0.164	0.102	-1.61	0.108	-0.363	0.036
214	SA	-0.160	0.388	-0.41	0.681	-0.921	0.602
12	SA	-0.129	0.212	-0.61	0.544	-0.55	0.29
9	SA	-0.124	0.426	-0.29	0.772	-0.96	0.71
175	SA	-0.123	0.273	-0.45	0.651	-0.658	0.412
149	SA	-0.004	0.431	-0.01	0.993	-0.850	0.842
209	SA	0.004	0.473	0.01	0.994	-0.925	0.933
43	SA	0.038	0.405	0.09	0.925	-0.76	0.83
59	SA	0.041	0.448	0.09	0.928	-0.84	0.92
205	SA	0.234	0.383	0.61	0.541	-0.517	0.986
42	SA	0.241	1.088	0.22	0.825	-1.89	2.38
162	SA	0.488	0.374	1.31	0.192	-0.245	1.221
78	WNC	-1.746	1.057	-1.65	0.099	-3.82	0.33
192	WNC	-1.127	0.243	-4.64	0	-1.604	-0.651
131	WNC	-0.654	0.332	-1.97	0.049	-1.307	-0.002
88	WNC	-0.622	0.261	-2.39	0.017	-1.13	-0.11
90	WNC	-0.615	0.364	-1.69	0.091	-1.33	0.10
150	WNC	-0.552	0.188	-2.94	0.003	-0.920	-0.184
114	WNC	-0.495	0.749	-0.66	0.509	-1.96	0.97
132	WNC	-0.476	0.447	-1.06	0.287	-1.353	0.401
77	WNC	-0.471	0.336	-1.4	0.162	-1.13	0.19
183	WNC	-0.463	0.115	-4.02	0	-0.688	-0.237
111	WNC	-0.440	0.303	-1.45	0.146	-1.03	0.15
136	WNC	-0.425	0.373	-1.14	0.255	-1.157	0.308
89	WNC	-0.352	0.221	-1.59	0.111	-0.79	0.08
79	WNC	-0.200	0.522	-0.38	0.701	-1.22	0.82
80	WNC	-0.200	0.522	-0.38	0.701	-1.22	0.82
81	WNC	-0.200	0.522	-0.38	0.701	-1.22	0.82
3	WNC	-0.190	0.411	-0.46	0.643	-1.00	0.62
108	WNC	-0.153	0.427	-0.36	0.719	-0.99	0.68
87	WNC	-0.124	0.404	-0.31	0.758	-0.92	0.67
195	WNC	-0.070	0.455	-0.15	0.878	-0.962	0.822
138	WNC	-0.052	0.419	-0.13	0.901	-0.874	0.769
185	WNC	0.041	0.406	0.1	0.921	-0.757	0.838
121	WNC	0.179	0.268	0.67	0.504	-0.346	0.704
99	WNC	0.489	0.717	0.68	0.496	-0.92	1.90
212	WNC	1.109	0.779	1.42	0.155	-0.420	2.638
51	WNC	1.404	0.422	3.32	0.001	0.58	2.23
135	WSC	-1.226	0.591	-2.07	0.038	-2.385	-0.067
6	WSC	-0.917	0.283	-3.24	0.001	-1.47	-0.36

215	WSC	-0.632	0.354	-1.78	0.075	-1.326	0.063
102	WSC	-0.615	0.344	-1.79	0.074	-1.29	0.06
124	WSC	-0.613	0.254	-2.42	0.016	-1.111	-0.115
13	WSC	-0.517	0.726	-0.71	0.476	-1.94	0.91
55	WSC	-0.485	0.335	-1.45	0.148	-1.14	0.17
167	WSC	-0.484	0.437	-1.11	0.268	-1.340	0.373
45	WSC	-0.464	0.265	-1.75	0.08	-0.98	0.06
19	WSC	-0.450	0.448	-1	0.315	-1.33	0.43
181	WSC	-0.318	0.331	-0.96	0.338	-0.968	0.332
156	WSC	-0.286	0.440	-0.65	0.516	-1.150	0.578
165	WSC	-0.272	0.404	-0.67	0.502	-1.065	0.522
21	WSC	-0.154	0.292	-0.53	0.597	-0.73	0.42
68	WSC	-0.108	0.234	-0.46	0.646	-0.57	0.35
70	WSC	-0.091	0.508	-0.18	0.858	-1.09	0.91
180	WSC	0.023	0.587	0.04	0.969	-1.129	1.174
8	WSC	0.066	0.406	0.16	0.872	-0.73	0.86
203	WSC	0.447	0.205	2.18	0.03	0.044	0.851
61	WSC	0.452	0.317	1.43	0.154	-0.17	1.07
50	WSC	0.486	0.427	1.14	0.255	-0.35	1.32
143	WSC	0.614	0.440	1.39	0.163	-0.250	1.477

The utility results also have a wide range of price elasticity estimates. The minimum value is –1.75 and the maximum is 1.40. In general, the estimates are representative of the results from the state-level analysis in residential electricity. Most estimates are negative and in the inelastic range. Some are positive in each region. Overall, these results suffer from a lack of precision also. Only about 17% of the utilities in the sample were statistically significant. Some of this variation in the estimates may be explained by the large differences in the size of utilities.

We tested for first-order autocorrelation in the error term and the results indicate it may be present. The estimate of ρ for the utility-level model was -0.32 with a t-statistic of -3.27. The results suggest first-order autocorrelation in the error term and we, therefore, ran the model to account for an AR(1) structure in the error term.

Results from Energy Use Trend Analysis

The trend analysis fits a linear trend to the variable of interest. Many of the trends in the data were linear and the model fit well. In some cases, particularly the natural gas market, the trends were not linear and the model had a poorer fit.

This section will now display the trend analysis results first for the region level and then at the state level.

Regional-Level Results

The model has the form:

$$\ln y_{it} = \alpha + \text{year}_t\, \beta + \text{region}_i\, \delta_i + (\text{region}_i \text{ x } \text{year}_t)\, \beta_i + \varepsilon_{it}$$

The model includes an indicator variable for region and an interaction term between region and year. These terms allow the slope of the trend and y-intercept to vary freely for each region.

Residential Electricity

Table D.17: Regional trends in residential electricity energy intensity

	Coef	Std. Err.	t	P>|t|	95% Conf	Interval
South Atlantic	1.94%	0.08%	25.7	0.0	1.79%	2.09%
East South Central	1.79%	0.11%	16.8	0.0	1.59%	2.00%
West South Central	1.59%	0.11%	14.9	0.0	1.38%	1.80%
West North Central	1.45%	0.08%	18.0	0.0	1.29%	1.61%
East North Central	1.40%	0.10%	14.6	0.0	1.21%	1.58%
Mid Atlantic	1.33%	0.12%	10.8	0.0	1.09%	1.57%
New England	0.91%	0.09%	10.4	0.0	0.73%	1.08%
Mountain	0.80%	0.08%	10.6	0.0	0.65%	0.95%
Pacific Coast	-0.12%	0.12%	-1.0	0.3	-0.36%	0.12%

Intensity is measured as quantity of residential electricity per capita. The table shows per capita electricity use is growing fastest in the South Atlantic and Central regions. Growth in per capita electricity use is negligible in the Pacific Coast region.

Table D.18: Regional trends in residential electricity expenditures

	Coef	Std. Err.	t	P>|t|	95% Conf	Interval
New England	0.717%	0.111%	6.49	0	0.500%	0.934%
Pacific Coast	0.680%	0.156%	4.35	0	0.373%	0.987%
East South Central	0.624%	0.135%	4.61	0	0.358%	0.890%
South Atlantic	0.621%	0.096%	6.48	0	0.433%	0.809%
West South Central	0.518%	0.135%	3.83	0	0.253%	0.784%
Mid Atlantic	0.316%	0.156%	2.02	0.04	0.009%	0.623%
West North Central	0.143%	0.102%	1.4	0.16	-0.058%	0.344%
East North Central	0.122%	0.121%	1.01	0.32	-0.116%	0.359%
Mountain	0.008%	0.096%	0.09	0.93	-0.180%	0.196%

Expenditures are growing fastest in the New England and Pacific Coast regions. Growth in expenditures is negligible in the Mountain region. Overall, the growth rates are all less than 1%.

Table D.19: Regional trends in residential electricity expenditures as a share of income

	Coef	Std. Err.	t	P>|t|	95% Conf	Interval
Mid Atlantic	-1.99%	0.17%	-12.08	0	-2.32%	-1.67%
West North Central	-1.98%	0.11%	-18.32	0	-2.19%	-1.77%
East North Central	-1.90%	0.13%	-14.83	0	-2.15%	-1.65%
Mountain	-1.83%	0.10%	-18.07	0	-2.03%	-1.63%
New England	-1.82%	0.12%	-15.58	0	-2.05%	-1.59%
East South Central	-1.80%	0.14%	-12.57	0	-2.08%	-1.52%
South Atlantic	-1.71%	0.10%	-16.9	0	-1.91%	-1.51%
West South Central	-1.46%	0.14%	-10.24	0	-1.74%	-1.18%
Pacific Coast	-1.19%	0.17%	-7.21	0	-1.51%	-0.87%

The trends in expenditures as a share of income show that income growth is faster than the increase in energy expenditures. Therefore, energy expenditures as a portion of household budgets is generally decreasing. The regional differences in the rate of decrease vary by about 1%. Expenditures as a share of income are declining fastest in the Mid Atlantic at about 2%. Decline is slowest in the Pacific Coast region at approximately 1%.

Commercial Electricity

Table D.20: Regional trends in commercial energy intensity

Regional commercial energy intensity trends				R-square = 0.57		
	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
New England	2.32%	0.20%	11.42	0	1.92%	2.72%
West North Central	2.18%	0.30%	7.15	0	1.58%	2.77%
South Atlantic	1.97%	0.20%	9.9	0	1.58%	2.36%
Mid Atlantic	1.78%	0.25%	7.01	0	1.28%	2.28%
East North Central	1.49%	0.20%	7.58	0	1.10%	1.87%
Mountain	1.48%	0.29%	5.19	0	0.92%	2.04%
West South Central	0.96%	0.25%	3.81	0	0.47%	1.45%
East South Central	0.94%	0.46%	2.04	0.041	0.04%	1.84%
Pacific Coast	0.25%	0.32%	0.8	0.425	-0.37%	0.88%

Intensity is measured as quantity of commercial electricity per unit of commercial floorspace. The results show statistically significant differences in the annual growth rates. The Pacific Coast rate is near zero, whereas the annual growth rates are over 2% in New England and the West North Central. All the trend estimates are statistically significant, except the Pacific Coast region. However, the model fit is only moderate, which is shown by the adjusted R-squared of 0.57.

Natural Gas

Table D.21: Regional energy intensity trends for residential natural gas

Regional Trend in Natural Gas Energy Intensity				R-squared	0.4302	
	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	1.09%	0.60%	1.84	0.067	-0.08%	2.26%
Mid Atlantic	0.45%	0.17%	2.7	0.007	0.12%	0.78%
New England	0.15%	1.08%	0.14	0.892	-1.97%	2.26%
Mountain	-0.41%	0.39%	-1.06	0.288	-1.17%	0.35%
South Atlantic	-0.45%	0.71%	-0.63	0.529	-1.85%	0.95%
East North Central	-0.47%	0.19%	-2.41	0.016	-0.85%	-0.09%
East South Central	-0.57%	0.31%	-1.87	0.062	-1.17%	0.03%
West North Central	-0.60%	0.23%	-2.66	0.008	-1.05%	-0.16%
West South Central	-2.05%	0.28%	-7.41	0	-2.60%	-1.51%

In this case, we measured energy intensity as the quantity of natural gas consumed per capita. The results show much different regional trends. Residential natural gas energy intensity is increasing in the Pacific Coast, Mid Atlantic, and New England regions. The trend is a slight decline in the South Atlantic and Central regions, except for the West South Central where intensity is declining over 2% per year.

The model fit is only fair in this case. The r-squared for this model is 0.43. The natural gas trends generally have two peaks, which is why the linear fit is limited.

Table D.22: Regional trends in natural gas energy expenditures

Regional Trend in Natural Gas Energy Expenditures				R-squared	0.3345	
	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	1.01%	0.45%	2.25	0.025	0.13%	1.89%
Mid Atlantic	0.75%	0.20%	3.85	0	0.37%	1.14%
East South Central	0.70%	0.34%	2.06	0.04	0.03%	1.36%
South Atlantic	0.47%	0.64%	0.74	0.458	-0.78%	1.73%
West North Central	0.14%	0.25%	0.55	0.579	-0.36%	0.64%
New England	-0.04%	1.08%	-0.04	0.971	-2.16%	2.08%
Mountain	-0.15%	0.28%	-0.53	0.595	-0.71%	0.41%
East North Central	-0.15%	0.23%	-0.65	0.517	-0.61%	0.31%
West South Central	-0.56%	0.29%	-1.93	0.054	-1.14%	0.01%

The trend is rising expenditures in the Pacific Coast, Mid Atlantic, East South Central, South Atlantic, and West North Central regions. Expenditures are falling in the New England, Mountain, East North Central, and West South Central regions. For most regions, the trend is near or less than 0.5% in absolute magnitude. Therefore, the estimates show that expenditures are relatively stable for most people.

The model fit is marginal in this case. Natural gas prices had several spikes and dropoffs, which is a nonlinear pattern. The expenditure data follow the price trend closely. Therefore, the linear fit is marginal for this variable.

Table D.23: Annual trends for natural gas expenditures as a share of income

R-squared 0.3865

Regional Trend in Natural Gas Energy Expenditures as Income Share

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Pacific Coast	-0.84%	0.40%	-2.09	0.036	-1.62%	-0.05%
Mid Atlantic	-1.56%	0.21%	-7.44	0	-1.97%	-1.15%
East South Central	-1.74%	0.34%	-5.06	0	-2.42%	-1.07%
South Atlantic	-1.85%	0.65%	-2.86	0.004	-3.11%	-0.58%
West North Central	-1.98%	0.24%	-8.4	0	-2.45%	-1.52%
Mountain	-1.99%	0.28%	-7.16	0	-2.53%	-1.44%
East North Central	-2.17%	0.22%	-9.84	0	-2.60%	-1.74%
New England	-2.49%	1.00%	-2.48	0.013	-4.45%	-0.52%
West South Central	-2.53%	0.32%	-7.96	0	-3.15%	-1.90%

The results show that expenditures as a share of income are falling in all regions. The most rapid decline is in the West South Central. The Pacific Coast trend has the most moderate decline. Again, the model fit is only marginal for the reasons stated above.

State-Level Results

The model has the form:

$$\ln y_{it} = \alpha + \text{year}_t\, \beta + \text{state}_i\, \delta_i + (\text{state}_i \text{ x year}_t)\, \beta_i + \varepsilon_{it}$$

The model includes an indicator variable for each state and an interaction term between state and year. These terms allow the slope of the trend and y-intercept to vary freely for each state.

Residential Electricity

Table D.24: Residential electricity energy intensity

Residential Energy Intensity

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
West Virginia	2.51%	0.05%	49.2	0	2.41%	2.61%
Delaware	2.49%	0.23%	10.81	0	2.04%	2.95%
Kentucky	2.43%	0.08%	29.32	0	2.26%	2.59%
Maryland	2.42%	0.13%	18.68	0	2.17%	2.68%
Mississippi	2.23%	0.08%	26.32	0	2.06%	2.39%
Alabama	2.18%	0.09%	23.46	0	2.00%	2.36%
South Carolina	2.16%	0.07%	29.65	0	2.01%	2.30%
Louisiana	2.14%	0.07%	32.43	0	2.01%	2.27%
Missouri	2.10%	0.11%	19.84	0	1.89%	2.31%
Kansas	1.97%	0.13%	14.98	0	1.71%	2.22%
Georgia	1.95%	0.08%	24.76	0	1.79%	2.10%
New Mexico	1.88%	0.08%	23.37	0	1.72%	2.04%
Virginia	1.85%	0.07%	28.03	0	1.72%	1.97%
Pennsylvania	1.76%	0.05%	36.67	0	1.66%	1.85%
North Dakota	1.76%	0.12%	14.68	0	1.52%	1.99%
North Carolina	1.71%	0.06%	27	0	1.59%	1.84%
Wyoming	1.71%	0.19%	8.93	0	1.33%	2.08%
Texas	1.64%	0.10%	17.04	0	1.45%	1.83%
Florida	1.64%	0.08%	20.98	0	1.49%	1.79%
Massachusetts	1.63%	0.06%	25.06	0	1.50%	1.75%
Arkansas	1.62%	0.17%	9.55	0	1.29%	1.96%
Ohio	1.62%	0.04%	38.3	0	1.54%	1.70%
Indiana	1.62%	0.05%	35.62	0	1.53%	1.71%
Nebraska	1.61%	0.10%	15.85	0	1.41%	1.81%
Oklahoma	1.60%	0.11%	14.27	0	1.38%	1.82%
New Jersey	1.59%	0.06%	27.69	0	1.48%	1.71%
Arizona	1.52%	0.07%	22.08	0	1.39%	1.66%
Rhode Island	1.49%	0.05%	31.61	0	1.40%	1.58%
New York	1.42%	0.05%	30.3	0	1.33%	1.51%
Michigan	1.40%	0.07%	19.1	0	1.25%	1.54%
Colorado	1.37%	0.21%	6.44	0	0.95%	1.79%
Connecticut	1.37%	0.06%	24.85	0	1.26%	1.48%
Minnesota	1.34%	0.08%	16.31	0	1.18%	1.51%
Utah	1.22%	0.08%	14.57	0	1.05%	1.38%
Illinois	1.19%	0.10%	11.66	0	0.99%	1.39%
Wisconsin	1.18%	0.08%	14.22	0	1.02%	1.34%
South Dakota	1.16%	0.11%	10.4	0	0.94%	1.37%
Iowa	1.06%	0.08%	12.6	0	0.90%	1.23%
Montana	0.79%	0.14%	5.51	0	0.51%	1.07%
Tennessee	0.69%	0.12%	5.66	0	0.45%	0.93%

New Hampshire	0.61%	0.10%	6.18	0	0.42%	0.80%
Maine	0.60%	0.12%	4.82	0	0.35%	0.84%
Vermont	0.32%	0.17%	1.92	0.055	-0.01%	0.65%
California	0.28%	0.07%	3.99	0	0.14%	0.42%
Nevada	0.07%	0.12%	0.59	0.554	-0.16%	0.30%
Oregon	0.00%	0.08%	0.01	0.994	-0.16%	0.16%
Idaho	-0.01%	0.11%	-0.11	0.915	-0.23%	0.20%
Washington	-0.57%	0.16%	-3.48	0.001	-0.89%	-0.25%

The results show that per capita residential electricity use is growing quickly in southern states. All of the states with a growth rate over 2% are in the South Atlantic and East South Central regions. The growth rate is considerably smaller (less than 0.5%) in Vermont, California, Nevada, Oregon, Idaho, and Washington. Notably, Oregon, Idaho, and Washington have zero growth or declining per capita use.

Table D.25: Trends in expenditures on residential electricity as a share of income

Residential Electricity Income Share

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Utah	-2.79%	0.34%	-8.1	0	-3.46%	-2.11%
New Jersey	-2.47%	0.17%	-14.35	0	-2.80%	-2.13%
Tennessee	-2.33%	0.12%	-19.39	0	-2.57%	-2.10%
Minnesota	-2.27%	0.21%	-10.71	0	-2.69%	-1.85%
South Dakota	-2.22%	0.34%	-6.52	0	-2.89%	-1.55%
New Hampshire	-2.17%	0.17%	-12.68	0	-2.51%	-1.84%
Illinois	-2.14%	0.40%	-5.38	0	-2.92%	-1.36%
Massachusetts	-2.09%	0.19%	-11.15	0	-2.46%	-1.72%
Wisconsin	-2.01%	0.25%	-8.03	0	-2.50%	-1.52%
Virginia	-1.98%	0.11%	-18.49	0	-2.20%	-1.77%
Colorado	-1.98%	0.41%	-4.88	0	-2.77%	-1.18%
Nevada	-1.97%	0.28%	-7.1	0	-2.52%	-1.43%
Arkansas	-1.96%	0.19%	-10.06	0	-2.34%	-1.58%
Iowa	-1.93%	0.25%	-7.85	0	-2.41%	-1.44%
Indiana	-1.92%	0.22%	-8.78	0	-2.35%	-1.49%
Delaware	-1.92%	0.12%	-16.57	0	-2.15%	-1.69%
Florida	-1.86%	0.18%	-10.39	0	-2.21%	-1.51%
Rhode Island	-1.84%	0.17%	-10.55	0	-2.19%	-1.50%
North Dakota	-1.81%	0.30%	-5.99	0	-2.40%	-1.21%
Arizona	-1.78%	0.19%	-9.49	0	-2.14%	-1.41%
Nebraska	-1.76%	0.21%	-8.21	0	-2.18%	-1.34%
Michigan	-1.75%	0.09%	-20.16	0	-1.92%	-1.58%
Connecticut	-1.73%	0.24%	-7.33	0	-2.19%	-1.26%
Idaho	-1.70%	0.31%	-5.46	0	-2.31%	-1.09%
Oregon	-1.62%	0.17%	-9.37	0	-1.96%	-1.28%

Kentucky	-1.61%	0.31%	-5.21	0	-2.21%	-1.00%
Missouri	-1.58%	0.21%	-7.69	0	-1.99%	-1.18%
North Carolina	-1.58%	0.17%	-9.48	0	-1.90%	-1.25%
Alabama	-1.55%	0.17%	-8.97	0	-1.89%	-1.21%
Vermont	-1.50%	0.17%	-8.81	0	-1.83%	-1.16%
New Mexico	-1.49%	0.27%	-5.59	0	-2.02%	-0.97%
Ohio	-1.49%	0.19%	-7.87	0	-1.86%	-1.12%
Maryland	-1.42%	0.20%	-7.01	0	-1.82%	-1.02%
Georgia	-1.41%	0.12%	-12.09	0	-1.64%	-1.18%
Kansas	-1.38%	0.35%	-3.98	0	-2.05%	-0.70%
Oklahoma	-1.35%	0.26%	-5.15	0	-1.86%	-0.84%
Pennsylvania	-1.33%	0.16%	-8.22	0	-1.65%	-1.01%
New York	-1.33%	0.14%	-9.74	0	-1.59%	-1.06%
Mississippi	-1.33%	0.15%	-8.7	0	-1.62%	-1.03%
South Carolina	-1.29%	0.18%	-7.26	0	-1.64%	-0.94%
Texas	-1.29%	0.25%	-5.22	0	-1.77%	-0.80%
West Virginia	-1.12%	0.18%	-6.41	0	-1.47%	-0.78%
Washington	-1.10%	0.48%	-2.27	0.023	-2.04%	-0.15%
Maine	-1.04%	0.25%	-4.12	0	-1.53%	-0.54%
California	-0.73%	0.19%	-3.86	0	-1.10%	-0.36%
Louisiana	-0.59%	0.39%	-1.51	0.131	-1.36%	0.18%
Wyoming	-0.33%	0.51%	-0.65	0.517	-1.34%	0.67%
Montana	-0.27%	0.23%	-1.14	0.255	-0.73%	0.19%

The trends are declining in all states but the rates are considerably different. Nine states are declining at 2% per year or more. Four states are declining slower than 0.75%. There is a relatively even distribution of states between these points.

Commercial Electricity

We only estimated trends for commercial electricity energy intensity. We measure energy intensity for this variable is the amount of commercial electricity used per unit of commercial floorspace.

Table D.26: Estimates of the annual trend in commercial energy intensity

	Annual Trends - Commercial Energy Intensity (electricity / sq ft flooring)					
	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
New Hampshire	4.41%	0.21%	20.97	0	3.99%	4.82%
North Dakota	3.60%	0.34%	10.63	0	2.93%	4.26%
Wyoming	3.41%	0.45%	7.55	0	2.52%	4.29%
South Dakota	3.19%	0.18%	17.49	0	2.84%	3.55%
Vermont	2.89%	0.17%	16.94	0	2.55%	3.22%
North Carolina	2.61%	0.08%	32.58	0	2.45%	2.77%
Georgia	2.47%	0.24%	10.1	0	1.99%	2.95%
Maine	2.45%	0.18%	13.65	0	2.10%	2.81%

Alabama	2.40%	0.29%	8.43	0	1.85%	2.96%
Delaware	2.35%	0.21%	11.27	0	1.94%	2.76%
Maryland	2.34%	0.69%	3.41	0.001	0.99%	3.68%
Mississippi	2.32%	0.27%	8.75	0	1.80%	2.84%
Michigan	2.24%	0.25%	9.03	0	1.76%	2.73%
Missouri	2.11%	0.11%	18.8	0	1.89%	2.33%
West Virginia	2.06%	0.11%	19.46	0	1.85%	2.27%
New Mexico	2.04%	0.18%	11.63	0	1.69%	2.38%
Nebraska	2.01%	0.17%	12.11	0	1.68%	2.34%
Utah	1.99%	0.18%	11.21	0	1.64%	2.33%
New Jersey	1.95%	0.11%	18.44	0	1.74%	2.16%
Pennsylvania	1.81%	0.07%	25.32	0	1.67%	1.95%
Minnesota	1.70%	0.10%	17.38	0	1.51%	1.89%
Indiana	1.63%	0.12%	13.33	0	1.39%	1.87%
Rhode Island	1.62%	0.11%	14.08	0	1.39%	1.84%
Ohio	1.59%	0.14%	11.42	0	1.31%	1.86%
New York	1.58%	0.07%	21.73	0	1.44%	1.72%
Colorado	1.57%	0.26%	6.02	0	1.06%	2.08%
Montana	1.55%	0.54%	2.86	0.004	0.49%	2.61%
Florida	1.53%	0.09%	16.53	0	1.35%	1.72%
Kansas	1.41%	0.07%	19.97	0	1.28%	1.55%
Arkansas	1.38%	0.15%	9.41	0	1.09%	1.66%
Wisconsin	1.35%	0.10%	13.99	0	1.16%	1.54%
Kentucky	1.31%	0.07%	17.86	0	1.17%	1.45%
Texas	1.30%	0.09%	15.27	0	1.13%	1.47%
Connecticut	1.29%	0.09%	15	0	1.12%	1.46%
Massachusetts	1.26%	0.08%	15.03	0	1.10%	1.43%
Virginia	1.22%	0.07%	17.12	0	1.08%	1.36%
Iowa	1.21%	0.14%	8.48	0	0.93%	1.48%
South Carolina	1.18%	0.14%	8.62	0	0.91%	1.45%
Washington	0.86%	0.28%	3.06	0.002	0.31%	1.42%
Oklahoma	0.69%	0.17%	3.97	0	0.35%	1.03%
Arizona	0.64%	0.18%	3.58	0	0.29%	0.99%
Illinois	0.63%	0.14%	4.59	0	0.36%	0.90%
Oregon	0.56%	0.22%	2.59	0.01	0.14%	0.99%
Idaho	0.47%	0.18%	2.61	0.009	0.12%	0.83%
Louisiana	0.47%	0.08%	5.54	0	0.30%	0.64%
Nevada	0.20%	0.61%	0.34	0.737	-0.98%	1.39%
California	-0.66%	0.10%	-6.63	0	-0.86%	-0.47%
Tennessee	-2.27%	1.71%	-1.33	0.185	-5.64%	1.09%

The trend is increasing in almost all states and New Hampshire, North Dakota, Wyoming, and South Dakota have rapid growth over 3%. Ten states are growing at less than 1%. California and Tennessee have negative trends.

Natural Gas

Table D.27: Estimated trends for residential natural gas energy intensity

R-square = 0.97

Natural Gas Energy Intensity Trends

	Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
Vermont	3.09%	0.20%	15.5	0	2.70%	3.48%
Washington	2.66%	0.35%	7.67	0	1.98%	3.34%
Idaho	2.60%	0.57%	4.59	0	1.49%	3.72%
Oregon	2.53%	0.34%	7.43	0	1.87%	3.20%
New Jersey	1.57%	0.13%	11.72	0	1.31%	1.84%
North Carolina	1.39%	0.21%	6.54	0	0.97%	1.80%
Tennessee	1.16%	0.17%	6.7	0	0.82%	1.50%
New Hampshire	0.98%	0.14%	7.06	0	0.71%	1.25%
Connecticut	0.83%	0.11%	7.31	0	0.61%	1.05%
Rhode Island	0.81%	0.14%	5.78	0	0.54%	1.09%
North Dakota	0.60%	0.26%	2.31	0.021	0.09%	1.10%
Virginia	0.56%	0.20%	2.88	0.004	0.18%	0.95%
Massachusetts	0.55%	0.18%	3.11	0.002	0.20%	0.90%
New York	0.44%	0.09%	4.68	0	0.25%	0.62%
Delaware	0.23%	0.16%	1.42	0.157	-0.09%	0.55%
Minnesota	0.19%	0.14%	1.37	0.172	-0.08%	0.47%
South Carolina	0.15%	0.53%	0.28	0.777	-0.88%	1.18%
South Dakota	-0.08%	0.29%	-0.28	0.777	-0.65%	0.48%
Wisconsin	-0.09%	0.14%	-0.61	0.541	-0.36%	0.19%
Michigan	-0.12%	0.17%	-0.69	0.491	-0.45%	0.22%
Nevada	-0.20%	0.22%	-0.9	0.367	-0.64%	0.24%
New Mexico	-0.28%	0.17%	-1.61	0.109	-0.62%	0.06%
Wyoming	-0.31%	0.34%	-0.94	0.349	-0.97%	0.34%
Montana	-0.50%	0.24%	-2.08	0.037	-0.96%	-0.03%
Colorado	-0.53%	0.23%	-2.3	0.022	-0.98%	-0.08%
Indiana	-0.61%	0.13%	-4.79	0	-0.86%	-0.36%
Iowa	-0.62%	0.15%	-4.21	0	-0.91%	-0.33%
Illinois	-0.63%	0.13%	-4.78	0	-0.89%	-0.37%
Georgia	-0.64%	0.18%	-3.53	0	-0.99%	-0.28%
Pennsylvania	-0.66%	0.12%	-5.65	0	-0.89%	-0.43%
Maryland	-0.72%	0.22%	-3.24	0.001	-1.16%	-0.28%
Ohio	-0.90%	0.14%	-6.6	0	-1.17%	-0.63%
Mississippi	-0.98%	0.22%	-4.4	0	-1.41%	-0.54%
Nebraska	-1.01%	0.14%	-7.22	0	-1.29%	-0.74%
Alabama	-1.11%	0.15%	-7.6	0	-1.40%	-0.82%
West Virginia	-1.46%	0.18%	-8.05	0	-1.81%	-1.10%
Kentucky	-1.52%	0.24%	-6.32	0	-1.99%	-1.05%
Oklahoma	-1.52%	0.17%	-8.92	0	-1.85%	-1.18%
Utah	-1.55%	0.30%	-5.11	0	-2.15%	-0.96%
Arkansas	-1.62%	0.13%	-12.16	0	-1.89%	-1.36%

Kansas	-1.64%	0.19%	-8.61	0	-2.02%	-1.27%
Missouri	-1.65%	0.14%	-11.63	0	-1.93%	-1.37%
California	-1.91%	0.16%	-11.68	0	-2.23%	-1.59%
Maine	-2.15%	2.20%	-0.98	0.329	-6.47%	2.17%
Arizona	-2.52%	0.32%	-7.92	0	-3.15%	-1.90%
Louisiana	-2.59%	0.23%	-11.37	0	-3.04%	-2.15%
Texas	-2.72%	0.31%	-8.76	0	-3.33%	-2.11%
Florida	-2.90%	0.37%	-7.9	0	-3.61%	-2.18%

The table shows large differences in the trends. Seventeen states have positive trends with four states growing over 2% per year. Thirty-one states have declining natural gas energy intenisity and five states are declining faster than 2% a year. Overall, the results show a wide range in the trends for this variable.

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 10:

With regard to Watkins testimony, Page 5, Lines 15-17, wherein he states "Even if Owen were to experience an erosion in sales due to technological change, it will presumably also gain cost efficiencies due to technological change as well."

a. Please identify these so-called "cost efficiencies", and provide the gains associated with them.

RESPONSE:

a. Please refer to Mr. Watkins' testimony, page 5, lines 17 through 22.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 11:

With regard to Watkins testimony, Page 6, Line 1, wherein he states "a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical" and, hence pricing should mirror those of a competitive firm and he cites Bonbright.

a. In competition, efficiency arises when price equals marginal cost. However, for a natural monopoly, pricing the good or product at this point results in losses and eventually shuts down the natural monopoly. Therefore, the government sets the price where price equates to average total cost. Here, the natural monopoly is able to realize reasonable economic profit. In the rate design proposed by Owen, the customer charge is the average total cost of providing basic service and any charges above that is the cost of providing kWh's, the marginal cost. Please explain then how the rate structure proposed by Owen does not uphold economic principles in that zero economic profits are earned.
b. Can a natural monopoly price it's goods or services at a rate where price equals marginal cost and remain economically viable? If one can, please provide examples of same.

RESPONSE:

a. Objection, relevance. The question as posed exceeds the scope of Mr. Watkins' testimony and the issues presented in the instant case. Without waiving this objection, the request is based on an argument that is incorrect. However, please refer to Mr. Watkins' testimony, page 7, line 10 through page 9, line 15.

b. In an unregulated environment, a monopoly will not establish prices at marginal cost, but rather above this level at the point along the demand curve. This is the fundamental basis for the theory of competition such that under competition, monopoly profits are eliminated and prices are forced to marginal cost (which include a fair rate return on capital employed).

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 12:

With regard to Watkins testimony, Page 6, Lines 13-20, the question asked of him was to discuss how prices are generally structured in competitive markets. In his answer, Watkins contends that efficient prices result when prices are equal to marginal costs and he contends in the long run, all costs are variable even if there is a high amount of fixed costs or excess capacity.

a. How then should Owen pay for excess capacity when regulation and good utility practice dictates that we keep this excess capacity for peak days?
b. Explain in detail how volume based pricing relates to marginal costs.
c. When or how will Owen reach the long run, and likewise maximize efficiency, given the fact that, in reality, firms operate in the short run since the long run is never met in a dynamic market?

RESPONSE:

a. Reasonable reserve margins are not considered "excess capacity." It is Mr. Watkins experience that "good utility practice" does not dictate excess capacity.

b. Please see Mr. Watkins' testimony, page 6, line 22 through page 7, line 8.

c. Objection, relevance. The question as posed exceeds the scope of Mr. Watkins' testimony and the issues presented in the instant case. Without waiving this objection, the request is based on an argument which, with all due respect, is nonsensical. However, the "long-run" is defined as the time period in which a firm's resources are replaced and/or capital is significantly expanded. This time horizon for Owen or any distribution electric utility varies depending on the specific resource in question but varies from about 10 years for metering equipment to 35 years for lines.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 13:

With regard to Watkins testimony, Page 6, Lines 25-28, and Page 7, Lines 1-8, he states that under efficient pricing principles, prices are variable in nature so to capture the variability of costs. In the pricing structure facing Owen, prices are not fully variable in that to change prices a costly and justifiable rate case is required. Therefore, is it viable for Owen to price its rates like a competitive market? If so why?

a. Owen is setting the price per kWh equal to the marginal cost (wholesale price). Please explain then how this contradicts the competitive market theory in which you are suggesting Owen participate in.

RESPONSE:

13. As set forth in this request, Owen may only change prices as a result of regulatory approval. Firms operating in competitive markets do not require regulatory approval. Therefore, in the context of this request, the answer is no.

    a. Mr. Watkins disagrees with the argument that Owen is proposing to set its prices at marginal costs.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 14:

With regard to Watkins testimony, Page 7, Lines 10-19, wherein on Line 18, he contends that customer costs are a measure of incremental change in costs resulting from a corresponding incremental change in the number of customers. How can this be applied to Owen when one, the customer cost is measured by the average customers, and two, the incremental cost varies for each customer?

a. Is Watkins advocating that each customer (member) pay something different as it relates to the actual cost of providing service to that individual customer (member)?
b. If Watkins believes Owen's current rate design is efficient and appropriate, then why wouldn't a rate neutral design that merely adjusts the allocation of charges, and wherein the overall annual bill does not significantly change, also not be efficient and appropriate?
c. Please provide copies of all published studies that relate to marginal cost pricing in other cooperatives of comparable size and density to Owen.

RESPONSE:

14. Please see Mr. Watkins testimony, page 15, line 22 through page 16, line 12.

    a. No.

    b. Please see (a) above.

    c. Mr. Watkins has never conducted nor is he aware of any marginal cost studies specifically for cooperatives.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 15:

With regard to Watkins testimony, Page 7, Lines 12-13, wherein he states that three separate categories of marginal costs exist and they include customer, demand and energy. These are the same categories in the classification process of an embedded cost of service study. Should not the prices/rates be based upon the most appropriate cost drivers? Provide support for your position.

RESPONSE:

From a purely economic efficiency perspective, yes. However, the majority of an electric utility's distribution costs are demand-related and therefore, should theoretically be collected from demand charges if economic efficiency is the **only** objective. As is well known, residential and small commercial customers are generally not equipped with demand meters (for a variety of reasons). As such, the industry practice has been to use a second best approach by collecting demand costs through energy (KWH) charges.

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 2

QUESTION 16:

With regard to Watkins testimony, Page 8, Lines 4-26, wherein he states that with volumetric pricing the more benefits a consumer receives, the more they pay. Please provide proof that the revenue neutral rate suggested by Owen contradicts volumetric pricing. Is the bill not higher if one uses more kWh?

a. Watkins states this so-called belief of volumetric pricing referenced in Lines 7 -18 of his testimony has been in place since the 1800's. Is he suggesting that we are living in the same world where we want to promote sales so as to make normal margins and continue in the way of the 1800's? Please provide published studies in support of said position.

b. Please provide copies of the marginal cost studies Watkins claims in his testimony he conducted or evaluated involving electric utilities in Connecticut, Illinois, Maine, Virginia, and Washington, DC.

   1) Are the electric utilities referred to in 14 b above, Connecticut, Illinois, Maine, Virginia, and Washington, DC. , of similar density, management, structure, and general characteristics as Owen? If not, do you believe they are valid comparisons to Owen? If they are not valid comparisons, do you have any studies that support your position? If so please provide copies of those studies.

   2) With regards to Watkins testimony on Page 8, Line 11-18, wherein he discusses fairness and equity. In the real world a $6 to $8 customer charge does not begin to cover the electric cooperative customer related costs of $27. Would Watkins agree that if a cooperative member uses minimal amounts of energy, significantly less than the average, then they shift consumer related costs to other members who use more energy? Please address how this is fair and equitable?

WITNESS RESPONSIBLE:
Glenn Watkins
Page 2 of 2

RESPONSE:

16. Yes. Mr. Watkins disagrees that Owen's proposed rate structure is revenue neutral to all ratepayers. Yes, the bill is higher with more KWH consumption.

   a. No.

   b. After searching prior case folders, the only marginal cost study retained concerns Central Maine Power Company. Please see attached study (As Attachment 1).

      1) No. All margin cost studies conducted or evaluated by Mr. Watkins have involved investor-owned utilities with higher customer densities than is assumed to be the case for Owen. Mr. Watkins has no opinion as to any differences in "management structure." The principle concepts of proper pricing signals and rate structures are generally the same for Owen as they are for all electric utilities.

      2) The request is predicated on an argument that Mr. Watkins disagrees with. As such, Mr. Watkins disagrees.

WATKIN'S RESPONSE TO OWEN
QUESTION 16
ATTACHMENT 1

BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

CENTRAL MAINE POWER COMPANY

DOCKET NO. 89-68

PREFILED SURREBUTTAL TESTIMONY

OF GLENN A. WATKINS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is 8 North Harrison Street, Richmond, Virginia 23220.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a Staff Economist with Technical Associates, Incorporated, which is a business research and consulting firm with main offices in Richmond, Virginia. Except for a six month period during 1987 in which I worked for a generation and transmission electric cooperative, i.e., Old Dominion, as its forecasting and rate Economist, I have been employed by Technical Associates continuously since 1980.

In connection with work performed by the firm, I have conducted cost of capital, load forecasting, marginal and embedded cost of service and rate design studies involving numerous electric, gas, and telephone utilities.

I hold an M.B.A. and B.S. in economics from Virginia Commonwealth University. A more complete statement of my professional and educational background appears in the Appendix to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present and detail the marginal cost study undertaken by Dr. Ileo and myself on behalf of Bath Iron Works ("BIW").

Q. WHAT ARE THE RESULTS OF YOUR MARGINAL COST STUDY?

A. The results of our marginal cost study i.e., the BIW MC Study, are contained in Exhibit___(BIW-2), which consists of 10 schedules. As Schedule 1 shows, the total system MC or marginal revenue requirement of CMP, including Rate W-1, is $717,885,693. If Rate W-1 is excluded, total jurisdictional MC or marginal revenue requirement is $710,856,522.

Q. PLEASE OUTLINE THE MAJOR DIFFERENCES THAT EXIST BETWEEN BIW'S MC STUDY AND THE COMPANY'S MC STUDY.

A. There are five major factors that contribute to the differences between CMP's MC Study and BIW's MC Study. First, we have determined CMP's total generation and transmission demand MC on the basis of a single system coincident peak ("CP"), as opposed to a winter period average CP and a non-winter period average CP advocated by the Company and Staff. Second, a cost of capital of 10.67% recommended by Staff in the revenue requirement phase of these proceedings has been employed. Third, a discount rate for determining annual economic charges of 10.67% has been used. Fourth, we have adjusted the Company's CP peak demands to include IR-CMP interruptible contract demand amounts. Fifth, we have allocated marginal distribution costs to periods and classes on the basis of non-coincident peak ("NCP") demands. However, as I will explain in detail later, the difference between our method and CMP's method has no impact on total system marginal distribution costs--it only effects the allocation to periods and customer classes.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE CUSTOMER, DEMAND AND ENERGY UNITS THAT WERE USED TO DETERMINE CMP'S TOTAL MARGINAL COSTS.

A. The customer, KW, and KWH units are summarized on Schedule 2. We have accepted the Company's average number of customers [Column (1)] and KWH usages [Columns (4) through

(10)]. We have, however, determined generation and transmission KW demands based on a single probability of CP demand as opposed to the winter average and summer average CP's used by CMP and Staff.

Q. WHY DO THE CLASS CP CONTRIBUTIONS ON SCHEDULE 2 VARY BETWEEN GENERATION AND TRANSMISSION WHILE THE TOTAL CMP SYSTEM AMOUNT IS VIRTUALLY THE SAME UNDER BOTH?

A. First, let me note that both the generation and transmission CP demands are expressed at the generation level, taking into account losses. The customer class contributions to the system peak of 1,587,893 KW were developed on the basis of the Company's probability of peak analyses. Since there are somewhat different probabilities of peak associated with generation and transmission facilities, the resulting customer class contributions to the annual system peak are somewhat different.

Q. HOW ARE THE CUSTOMER CLASS CONTRIBUTIONS FOR GENERATION AND TRANSMISSION USED IN YOUR DETERMINATION OF CMP'S TOTAL MC?

A. Each customer class' KW contribution to generation CP is multiplied by that class' respective unit marginal demand cost for generation, to arrive at total generation demand MC. To illustrate for the A&R class, the figure of $44.04 in Column

(1) of Page 2 of Schedule 3 is multiplied by 544,162 in Schedule 2 to produce on-peak MC of generation of $23,964,014 on Page 3 of Schedule 1.

Q. HOW WERE THE INDIVIDUAL CLASS CONTRIBUTIONS TO GENERATION AND TRANSMISSION CP DEMANDS DEVELOPED?

A. The derivation of the class responsibilities are shown in Schedule 5. The first three pages relate to generation, while Pages 4 through 6 relate to transmission. Page 7 shows adjustments to CMP's proforma CP demands. Since the format for the development of transmission CP's is identical to that for generation, I will limit my discussion to the latter.

The first step in calculating each class' responsibility to the annual system peak demand was to incorporate the monthly probabilities of peak for the CMP generation system. These probabilities are shown on the first row of Page 1 of Schedule 5, and are the same as those used by the Company in its development of period (seasonal and diurnal) cost responsibilities. These figures indicate that CMP's generation system has the highest probability of peaking in January (50.5%) and the lowest probability of peaking in August (0.2%).

The class contributions to each adjusted monthly CP demand are then multiplied by the monthly system probability of peak to determine each classes' percent contribution to the monthly weighted probability of peak as shown on Page 2. The monthly weighted percentage responsibilities are then summed, in Column (13) of Page 2, to arrive at the total annual weighted probability of peak for each class.

These class responsibilities are then multiplied by the adjusted annual system peak of 1,587,893 KW to determine the CP contributions of each class. These are shown on Page 3 of Schedule 5, which are brought forward to Schedule 2.

Q. YOU HAVE INDICATED THAT YOU USED ADJUSTED CP DEMANDS FOR EACH MONTH, PLEASE EXPLAIN.

A. I have accepted the Company's proforma monthly CP demands contained in their Updated TDAC study with one exception. I have made an adjustment to reflect interruptible customer loads under the IR-CMP rate, which have a small affect on MGS-S, LGS-ST and LGS-T classes as indicated on Page 7 of Schedule 5.

Q. PLEASE EXPLAIN WHY THESE ADJUSTMENTS WERE MADE.

A. On Page 25 of his rebuttal testimony, Mr. Maheu acknowledges that interruptible loads under the IR-NPL rate should be subtracted from actual loads to determine class CP responsibilities, since NEPEX will recognize IR-NPL contract loads in the determination of CMP's capability responsibility.

However, in Mr. Maheu's opinion, IR-CMP contract loads should not be subtracted since NEPEX only recognizes these amounts if an actual interruption is in effect during the monthly peak hour.

With respect to the IR-CMP contract loads, Mr. Maheu fails to account for the fact that CMP's capability responsibilities would have been reduced had these customers been interrupted; something that CMP certainly could have done at the time of each winter monthly peak. However, under the terms of the IR-CMP rate, CMP can only interrupt these customers during the winter months. Thus, reductions for IR-CMP contract amounts during the summer months are not appropriate.

Given the fact that CMP could (and possibly should) have interrupted the IR-CMP customers during the winter monthly peaks, I have adjusted CMP's monthly CP's by the IR-CMP contracted amounts. It should be noted that no adjustments were made to the LGS-ST and LGS-T classes during January and December since these customers were actually interrupted at the time of the monthly peak. Therefore, as Page 7 of Schedule 5 shows, the end-result was to reduce: (1) MGS-S CP's for January, February, March, and December; and (2) LGS-ST and LGS-T CP's during February and March.

Q. HAVE YOU MADE ANY ADJUSTMENTS TO REFLECT IR-W-VOL CONTRACTED LOADS?

A. No, these amounts were not considered for two reasons. First, even though the voluntary interruptible customers tend to agree to curtail at least some of their loads when asked, I do not know the extent to which they complied with what was requested. Second, even though there is an incentive for customers to comply with an interruption request, there are no penalties imposed if the customer refuses. Therefore, I do not believe these voluntary interruptible loads are sufficiently reliable for planning and costing purposes.

Q. PLEASE EXPLAIN HOW YOU CALCULATED MARGINAL DISTRIBUTION DEMAND COSTS?

A. The determination of total distribution demand costs is contained in Schedule 4, which consists of six pages. As indicated earlier, our method of allocating distribution demand costs to periods and classes is different than that used by either the Company or Staff. However, our total system distribution revenues would be the same had we used the Company's or Staff's method of assigning distribution costs to periods and classes.

There are two components in the determination of the distribution demand costs: (1) those relating to Primary Voltage facilities; (2) and those relating to Secondary Voltage facilities. The total marginal costs associated with these two types of facilities are shown on Page 1 of Schedule

4 as $60,798,622 for Primary and $38,554,505 for Secondary.

The CP unit marginal distribution demand cost of serving a customer at the primary level is $45.82 per year. The coincident peak demand (at generation) of all customers served by primary facilities is 1,287,254. Therefore, the total marginal cost ($58,981,978) associated with primary facilities at the primary level is the product of these two figures. However, there are additional marginal costs to the primary system due to voltage losses of secondary customers. These losses contribute an additional $1.57 per CP of demand for secondary customers. The CP demands of primary customers are subtracted from the 1,287,254 and multiplied by the $1.57 to determine an additional $1,816,644 of marginal primary costs attributable to secondary customers.

The $58,981,978 marginal costs for primary facilities, at the primary level is then allocated to periods and classes on the basis of period non-coincident peak ("NCP") demands as shown on page 2 of Schedule 4. This results in the assignment of $6,637,190 to primary customers and $52,344,788 to secondary customers. The additional primary distribution costs of $1,816,644 attributable solely to secondary customers is assigned to the secondary classes on the basis of their respective NCP's. The assignment of secondary facility marginal costs to periods and classes is based on the same method as employed for the additional $1,816,644 primary costs, i.e., allocated on the basis of secondary customer NCP's.

Q. ARE THERE ANY DIFFERENCES IN THE UNIT MARGINAL ENERGY COSTS USED IN THE BIW MARGINAL COST STUDY COMPARED TO THE COMPANY'S MC STUDY?

A. The only difference between the Company's marginal energy costs and ours is that CMP used a marginal cost of capital of 11.66% in determining the Working Capital revenue requirement, where we used a cost of capital of 10.67%. The difference is so small that for most classes the unit marginal costs are identical. For those that differ, the maximum amount of difference is only .01 mill per KWH.

Q. PLEASE EXPLAIN YOUR DEVELOPMENT OF UNIT MARGINAL CUSTOMER AND DEMAND COSTS.

A. The method of determining unit marginal customer and demand costs is identical to that used by CMP, except that we have used a cost of capital of 10.67% and a discount rate of 10.67% to calculate annual economic charges. In addition, working capital revenue requirements were calculated using the 10.67% cost of capital rather than 11.66% as used by the Company. These result in minor differences in unit customer, transmission, and distribution demand costs, and moderate differences in unit generation costs. The determination of unit marginal customer and demand costs follows the same format as presented by CMP in its rebuttal filing. Our methodology is shown in Schedules 7 through 10 of Exhibit___(BIW-2).

Q. WHY DO THESE RESULT IN MODERATE DIFFERENCES IN UNIT GENERATION COSTS AND SMALL DIFFERENCES IN OTHER MARGINAL DEMAND COSTS?

A. Marginal unit generation costs are more sensitive to differences in capital costs and discount rates due to the shorter life of a gas turbine vis a vis transmission and distribution facilities. This sensitivity rests in the calculation of annual economic carrying charges, i.e., since a peaker is used as the incremental investment, generation plant revenue requirements are determined and discounted over a shorter period of time than is the case for transmission and distribution plant. Hence, shorter lived plant is impacted to a greater degree by changes in capital costs and discount rates.

Q. HAVE YOU COMPLETED YOUR TESTIMONY?

A. Yes I have.

APPENDIX

BACKGROUND & EXPERIENCE PROFILE
GLENN A. WATKINS
STAFF ECONOMIST

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Aug. 1987-Present	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utilities

A. Costing Studies

1. Electric Utilities -- Performed comparative evaluation of alternative embedded cost allocation methods with particular emphasis on ratemaking implications of alternative methods of capacity cost allocation. Embedded cost studies have been conducted for jurisdictional separations, inter-class cost allocations, and intra-class cost incidence. Alternative procedures have been assessed for determining and allocating the demand and customer components of the embedded cost of distribution systems.

Analyzed embedded and marginal cost studies relating to the seasonal and diurnal distribution of system energy and demand costs, as well as cost reflective approaches to incorporating energy and demand losses for rate design purposes. Marginal cost analyses have been based upon the NERA "peaker" methodology.

2. Gas Utilities -- Analyzed cost of service studies of gas transmission and distribution companies. Project team member in studies of system cost allocation procedures and of the allocation of costs to customer classes based on such variables as the relationship of weather to system sales and capacity requirements.

3. Telephone Companies -- Analyses of cost of service studies performed by telephone companies employing embedded direct analysis (EDA) and incremental costs. EDA studies have been analyzed for both pre and post AT&T divestiture.

B. Rate Design Studies

1. Electric Utilities -- Analyzed and designed rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

2. Gas Utilities -- Evaluated the extent to which alternative rate structures of gas distribution companies reflect cost imposition while simultaneously recovering required revenues and maintaining acceptable levels of customer understanding. Assessed the distribution of impacts of alternative rate structures among customers.

C. Forecasting and System Profile Studies -- Development of long range energy and demand forecasts for rural electric cooperatives (Generation & Transmission as well as distribution coops). Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, start-up costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earning, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Project team member for numerous accounting studies on revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, CWIP-IDC studies, and rate base and operating income adjustments.

II. Transportation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Assistance in cost of capital and revenue adequacy studies of railroads.

C. Automobile Industry -- Project coordinator and analyses of economic and market impact studies involving automobile and truck dealership locations. Analyses included market and dealer performance, trends in market share and penetration, and future sales potential.

III. Anti-Trust

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market structures and performance of that market, the pricing and cost allocation practices of the manufacturers, and the economic performance of the manufacturers' distributors.

IV. <u>Computer Applications</u>

Extensive experience in developing models and programs utilizing: LOTUS 1-2-3; SAS; TSP; and PL-1.

CENTRAL MAINE POWER COMPANY
SUMMARY OF PERIOD TOTAL MARGINAL REVENUE REQUIREMENTS
FOR THE PERIOD 12 MONTH ENDING 12/31/88

Proposed Rate Classes	TOTAL CUSTOMER REVENUES [a] (1)	WINTER On-Peak (2)	WINTER Interim (3)	WINTER Off-Peak (4)	OTHER On-Peak (5)	OTHER Interim (6)	OTHER Off-Peak (7)	Total Annual Costs (8)
		TOTAL DEMAND & ENERGY REVENUES [b]						
A & R	37,564,156	74,433,104	23,581,198	25,283,244	36,030,417	12,118,998	39,916,458	248,927,576
A-TOU & R-TOU	3,612,088	30,283,262	8,926,807	11,369,021	8,022,584	3,088,879	7,762,378	73,065,020
SGS	4,232,449	9,872,371	3,547,415	3,435,478	5,419,625	2,925,700	4,929,596	34,362,635
MGS-S	3,298,952	34,517,754	11,606,381	12,766,206	19,949,252	9,674,156	18,835,753	110,648,453
MGS-P	114,629	1,044,841	350,816	373,673	547,495	254,721	516,454	3,202,629
IGS-S	259,979	8,576,447	2,920,813	3,127,397	5,895,277	3,112,428	5,021,461	28,913,803
IGS-P	125,147	3,910,368	1,215,298	1,402,735	2,241,608	1,019,859	2,135,810	12,050,826
LGS-S-TOU	104,776	2,200,414	729,844	871,092	1,380,041	694,649	1,243,531	7,224,347
LGS-P-TOU	382,656	13,114,117	3,845,301	5,141,256	8,082,094	3,678,401	8,991,970	43,235,794
LGS-ST-TOU	150,954	14,262,311	4,365,900	7,064,538	9,313,008	3,687,679	14,306,185	53,150,574
LGS-T-TOU	89,842	21,085,837	7,303,931	12,986,542	14,397,383	5,651,144	25,256,433	86,771,114
N	327	3,615	463	363	683	252	249	5,952
GSS	32,171	227,516	67,888	126,785	161,780	52,664	341,916	1,010,719
AL	1,369,493	290,590	30,737	164,334	85,291	1,610	291,798	2,233,853
SL	3,714,023	778,559	82,943	449,897	231,028	4,280	792,498	6,053,228
W-1	21,808	2,565,720	650,773	839,490	1,196,159	397,185	1,358,036	7,029,171
TOTAL COMPANY	55,073,450	217,166,825	69,226,509	85,402,053	112,953,725	46,362,605	131,700,527	717,885,693

[a] Per page 2.
[b] Sum of total marginal energy revenue (per page 2); total generation demand revenue (per page 3); total transmission demand revenue (per page 3): and total distribution demand revenue (per page 4).

CENTRAL MAINE POWER COMPANY
SUMMARY OF PERIOD CUSTOMER AND ENERGY MARGINAL REVENUE REQUIREMENTS
FOR THE PERIOD 12 MONTH ENDING 12/31/88

Proposed Rate Classes	Total Annual Customer Revenues [a]	WINTER On-Peak	WINTER Interim	WINTER Off-Peak	OTHER On-Peak	OTHER Interim	OTHER Off-Peak	Annual Energy Costs
		TOTAL ENERGY REVENUES [b]						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
A & R	37,564,156	16,027,564	12,241,174	16,791,241	22,576,000	7,208,380	31,934,282	106,778,641
A-TOU & R-TOU	3,612,088	4,559,156	3,729,199	6,738,630	3,371,552	1,573,176	5,721,865	25,693,579
SGS	4,232,449	2,532,536	1,898,342	2,174,930	3,530,038	1,765,610	3,940,948	15,842,404
MGS-S	3,298,952	8,141,588	6,142,658	8,287,460	13,187,448	6,091,079	15,595,688	57,445,920
MGS-P	114,629	308,343	226,172	293,129	398,507	189,244	467,585	1,882,981
IGS-S	259,979	2,395,220	1,646,511	2,088,631	4,101,737	1,945,912	4,168,612	16,346,623
IGS-P	125,147	1,090,828	774,814	1,080,285	1,663,968	761,766	1,915,585	7,287,245
LGS-S-TOU	104,776	604,396	401,064	603,800	953,130	446,545	1,038,708	4,047,643
LGS-P-TOU	382,656	3,602,153	2,421,528	4,052,834	6,063,230	2,756,768	8,185,839	27,082,352
LGS-ST-TOU	150,954	4,488,741	3,677,524	6,657,719	8,022,668	3,617,841	14,229,696	40,694,188
LGS-T-TOU	89,842	7,378,065	6,334,404	12,412,590	12,517,914	5,547,939	25,143,246	69,334,157
N	327	11	5	2	17	7	2	45
GSS	32,171	67,786	56,629	120,132	140,533	51,498	340,638	777,216
AL	1,369,493	34,003	15,239	118,305	19,094	0	253,216	439,857
SL	3,714,023	93,159	41,751	324,125	51,780	0	686,674	1,197,489
W-1	21,808	663,041	516,783	760,311	945,318	383,610	1,343,168	4,612,231
TOTAL COMPANY	55,073,450	51,986,591	40,123,799	62,504,125	77,542,934	32,339,373	114,965,751	379,462,573

[a] Annual marginal customer cost (per Schedule 3, page 1),times average number of customers (per Schedule 2_).
[b] Unit marginal energy cost (per Schedule 3, page 1),times kwh (per Schedule 2).

CENTRAL MAINE POWER COMPANY
SUMMARY OF PERIOD GENERATION AND TRANSMISSION DEMAND MARGINAL REVENUE REQUIREMENTS
FOR THE PERIOD 12 MONTH ENDING 12/31/88

Proposed Rate Classes	WINTER On-Peak (1)	WINTER Interim (2)	WINTER Off-Peak (3)	OTHER On-Peak (4)	OTHER Interim (5)	OTHER Off-Peak (6)	WINTER On-Peak (7)	WINTER Interim (8)	WINTER Off-Peak (9)	OTHER On-Peak (10)	OTHER Interim (11)	OTHER Off-Peak (12)
	GENERATION DEMAND REVENUES [a]						TRANSMISSION DEMAND REVENUES [b]					
A & R	23,964,014	1,855,524	1,148,140	6,078,066	337,368	370,017	27,055,644	1,739,059	975,173	671,786	32,506	32,506
A-TOU & R-TOU	10,272,198	795,372	492,151	2,605,369	144,613	158,608	11,628,080	747,420	419,114	288,723	13,970	13,970
SGS	2,836,000	219,590	135,876	719,303	39,926	43,789	3,239,258	208,210	116,753	80,430	3,892	3,892
MGS-S	10,443,998	808,675	500,382	2,648,943	147,032	161,261	11,767,312	756,369	424,132	292,180	14,138	14,138
MGS-P	302,488	23,443	14,492	76,723	4,262	4,689	351,816	22,590	12,679	8,744	437	437
IGS-S	2,432,505	188,348	116,544	616,964	34,245	37,559	2,806,278	180,380	101,147	69,679	3,372	3,372
IGS-P	1,180,786	91,512	56,571	299,495	16,639	18,302	1,365,020	87,646	49,195	33,928	1,696	1,696
LGS-S-TOU	625,852	48,460	29,985	158,737	8,811	9,663	723,531	46,506	26,078	17,965	869	869
LGS-P-TOU	4,058,768	314,559	194,455	1,029,467	57,193	62,912	4,642,122	298,065	167,301	115,380	5,769	5,769
LGS-ST-TOU	4,580,529	354,736	219,493	1,161,760	64,296	70,947	5,193,041	333,640	187,326	128,579	5,542	5,542
LGS-T-TOU	6,734,779	522,411	322,764	1,706,987	94,833	104,815	6,972,993	447,116	251,189	172,483	8,373	8,373
N	1,585	123	76	402	22	24	1,798	116	65	45	2	2
GSS	75,617	5,866	3,624	19,166	1,065	1,177	84,113	5,393	3,030	2,081	101	101
AL	104,507	8,092	5,007	26,506	1,471	1,614	115,212	7,405	4,153	2,861	138	138
SL	277,892	21,517	13,314	70,483	3,912	4,291	306,082	19,674	11,032	7,600	368	368
W-1	890,157	68,938	42,655	225,771	12,495	13,788	1,012,522	65,052	36,524	25,070	1,081	1,081
TOTAL COMPANY	68,781,675	5,327,166	3,295,528	17,444,142	968,182	1,063,455	77,264,823	4,964,642	2,784,893	1,917,533	92,254	92,254

[a] Unit marginal generation demand costs (per Schedule 3, page 2), times contribution to generation coincident peak demands [per Schedule 2, column (2)].
[b] Unit marginal transmission demand costs (per Schedule 3, page 2), times contribution to transmission coincident peak demands [per Schedule 2, column (3)].

CENTRAL MAINE POWER COMPANY
SUMMARY OF PERIOD DISTRIBUTION MARGINAL DEMAND REVENUE REQUIREMENTS
FOR THE PERIOD 12 MONTH ENDING 12/31/88

Proposed Rate Classes		WINTER On-Peak (1)	WINTER Interim (2)	WINTER Off-Peak (3)	OTHER On-Peak (4)	OTHER Interim (5)	OTHER Off-Peak (6)
		DISTRIBUTION DEMAND REVENUES					
A & R	[a]	7,385,882	7,745,441	6,368,690	6,704,564	4,540,745	7,579,654
A-TOU & R	[a]	3,823,828	3,654,816	3,719,126	1,756,940	1,357,119	1,867,935
SGS	[a]	1,264,577	1,221,272	1,007,919	1,089,854	1,116,273	940,967
MGS-S	[a]	4,164,855	3,898,679	3,554,232	3,820,681	3,421,908	3,064,667
MGS-P	[b]	82,193	78,611	53,372	63,520	60,778	43,743
IGS-S	[a]	942,443	905,575	821,075	1,106,897	1,128,899	811,919
IGS-P	[b]	273,734	261,326	216,684	244,218	239,758	200,226
LGS-S-TOU	[a]	246,635	233,814	211,229	250,209	238,424	194,290
LGS-P-TOU	[b]	811,074	811,148	726,666	874,017	858,671	737,450
LGS-ST-TOU		0	0	0	0	0	0
LGS-T-TOU		0	0	0	0	0	0
N	[a]	220	220	220	220	220	220
GSS		0	0	0	0	0	0
AL	[a]	36,869	0	36,869	36,830	0	36,830
SL	[a]	101,425	0	101,425	101,166	0	101,166
W-1		0	0	0	0	0	0
TOTAL COMPANY		19,133,735	18,810,902	16,817,507	16,049,116	12,962,795	15,579,067

[a] Per Schedule 4, Page 3.
[b] Per Schedule 4, Page 2.

CENTRAL MAINE POWER COMPANY
SUMMARY OF CUSTOMERS, COINCIDENT PEAK DEMANDS, AND KWH
FOR THE 12 MONTH PERIOD ENDING 12/31/88

Proposed Rate Classes	Average Customers [a]	GENERATION Coincident Peak Demand [b]	TRANSMISSION Coincident Peak Demand [c]	WINTER			OTHER			ANNUAL
				On-Peak	Interim	Off-Peak	On-Peak	Interim	Off-Peak	Total
		(Kilowatts)	(Kilowatts)	KILOWATTHOURS [a]						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
A & R	391,538	544,142	541,763	286,308,756	234,820,142	410,443,448	485,400,997	160,328,728	910,586,877	2,487,888,948
A-TOU & R-TOU	26,782	233,247	232,841	81,442,591	71,536,533	164,718,408	72,490,911	34,990,576	163,155,541	588,334,560
SGS	35,741	64,396	64,863	45,240,010	36,415,545	53,163,782	75,898,463	39,270,675	112,373,779	362,362,254
MGS-S	9,573	237,148	235,629	145,437,448	117,833,452	202,577,843	283,540,050	135,477,728	444,701,685	1,329,568,206
MGS-P	101	7,104	7,287	5,693,193	4,468,042	7,344,762	8,816,535	4,326,559	13,624,273	44,273,364
IGS-S	233	55,234	56,193	42,787,072	31,584,708	51,054,285	88,190,430	43,280,970	118,865,461	375,762,926
IGS-P	78	27,731	28,273	20,140,843	15,306,475	27,068,023	36,813,448	17,415,774	55,815,414	172,559,977
LGS-S-TOU	19	14,211	14,488	10,796,643	7,693,533	14,759,224	20,493,009	9,932,047	29,618,144	93,292,600
LGS-P-TOU	64	95,321	96,150	66,509,468	47,837,383	101,549,334	134,142,264	63,026,248	238,515,121	651,579,818
LGS-ST-TOU	21	110,855	110,844	86,789,260	75,684,785	172,658,687	184,683,891	85,954,873	427,446,552	1,033,218,048
LGS-T-TOU	9	166,373	167,459	147,237,384	134,061,459	329,596,133	296,141,791	135,315,581	771,028,688	1,813,381,036
N	2	36	36	205	99	56	359	159	62	940
GSS	2	1,868	2,020	1,352,746	1,198,507	3,189,897	3,324,657	1,256,047	10,445,806	20,767,660
AL	12,208	2,373	2,307	607,412	292,331	2,891,842	410,539	0	7,220,292	11,422,416
SL	47,007	6,310	6,129	1,664,149	800,911	7,922,886	1,113,305	0	19,580,091	31,081,342
W-1	3	21,543	21,612	12,819,813	10,635,586	19,717,599	21,761,475	9,114,037	40,347,490	114,396,000
TOTAL COMPANY	523,381	1,587,892	1,587,894	954,826,993	790,169,491	1,568,656,209	1,713,222,124	739,690,002	3,363,325,276	9,129,890,095

Per Exhibit Maheu-25, page 35.
Per Schedule 5, page 3.
Per Schedule 5, page 6.

CENTRAL MAINE POWER COMPANY
SUMMARY OF PERIOD UNIT ENERGY COSTS
FOR THE PERIOD 12 MONTH ENDING 12/31/88

Proposed Rate Classes	Annual Customer Cost	WINTER			OTHER		
		On-Peak	Interim	Off-Peak	On-Peak	Interim	Off-Peak
		CENTS PER KILOWATTHOUR					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
A & R	95.94	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
A-TOU & R-TOU	134.87	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
SGS	118.42	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
MGS-S	344.61	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
MGS-P	1,134.94	0.054160	0.050620	0.039910	0.045200	0.043740	0.034320
IGS-S	1,115.79	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
IGS-P	1,604.45	0.054160	0.050620	0.039910	0.045200	0.043740	0.034320
LGS-S-TOU	5,514.50	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
LGS-P-TOU	5,979.00	0.054160	0.050620	0.039910	0.045200	0.043740	0.034320
LGS-ST-TOU	7,188.29	0.051720	0.048590	0.038560	0.043440	0.042090	0.033290
LGS-T-TOU	9,982.49	0.050110	0.047250	0.037660	0.042270	0.041000	0.032610
N	163.34	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
GSS	16,085.52	0.050110	0.047250	0.037660	0.042270	0.041000	0.032610
AL	112.18	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
SL	79.01	0.055980	0.052130	0.040910	0.046510	0.044960	0.035070
W-1	7,269.24	0.051720	0.048590	0.038560	0.043440	0.042090	0.033290

Source: Customer costs - Schedule 9
Energy costs - Schedule 6.

CENTRAL MAINE POWER COMPANY
SUMMARY OF PERIOD UNIT GENERATION AND TRANSMISSION COSTS
FOR THE PERIOD 12 MONTH ENDING 12/31/88

Proposed Rate Classes	GENERATION						TRANSMISSION					
	WINTER			OTHER			WINTER			OTHER		
	On-Peak	Interim	Off-Peak	On-Peak	Interim	Off-Peak	On-Peak	Interim	Off-Peak	On-Peak	Interim	Off-Peak
	DOLLARS PER KILOWATT OF COINCIDENT PEAK DEMAND						DOLLARS PER KILOWATT OF COINCIDENT PEAK DEM					
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
A & R	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
A-TOU & R-TOU	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
SGS	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
MGS-S	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
MGS-P	42.58	3.30	2.04	10.80	0.60	0.66	48.28	3.10	1.74	1.20	0.06	0.06
IGS-S	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
IGS-P	42.58	3.30	2.04	10.80	0.60	0.66	48.28	3.10	1.74	1.20	0.06	0.06
LGS-S-TOU	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
LGS-P-TOU	42.58	3.30	2.04	10.80	0.60	0.66	48.28	3.10	1.74	1.20	0.06	0.06
LGS-ST-TOU	41.32	3.20	1.98	10.48	0.58	0.64	46.85	3.01	1.69	1.16	0.05	0.05
LGS-T-TOU	40.48	3.14	1.94	10.26	0.57	0.63	41.64	2.67	1.50	1.03	0.05	0.05
N	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
GSS	40.48	3.14	1.94	10.26	0.57	0.63	41.64	2.67	1.50	1.03	0.05	0.05
AL	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
SL	44.04	3.41	2.11	11.17	0.62	0.68	49.94	3.21	1.80	1.24	0.06	0.06
W-1	41.32	3.20	1.98	10.48	0.58	0.64	46.85	3.01	1.69	1.16	0.05	0.05

Source: Schedule 10, page 1.

TOTAL MARGINAL DEMAND COSTS
DISTRIBUTION

Primary Facilities:	
(1) Primary Facilities Marginal unit Cost per CP [a]	$45.82
(2) CP's of Primary and Secondary Classes [b]	1,287,254
(3) Subtotal: (1) x (2)	$58,981,978
(4) Additional Primary Facilities Marginal Unit Cost per CP for Secondary Classes [c]	$1.57
(5) CP's of Secondary Classes [b]	1,157,098
(6) Additional Cost of Primary Facilities for Secondary Classes: (4) x (5)	$1,816,644
(7) Total Marginal Cost of Primary Facilities: (3) + (6)	$60,798,622
Secondary Facilities:	
(8) Secondary Facilities Marginal Unit cost per CP [a]	$33.32
(9) CP's of Secondary Classes [b]	1,157,098
(10) Total Marginal Cost of Secondary Facilities: (8) x (9)	$38,554,505

[a] Per Schedule 10, page 2.
[b] Calculated per Schedule 5, page 3.
[c] Difference between $47.39 and $45.82, per Schedule 10, page 2.

Marginal Cost of Primary Distribution Facilities
at Primary Level [a]

Proposed Rate Classes	WINTER On-Peak (1)	WINTER Interim (2)	WINTER Off-Peak (3)	OTHER On-Peak (4)	OTHER Interim (5)	OTHER Off-Peak (6)	Annual Cost (7)
PRIMARY CLASSES:							
MGS-P	82,193	78,611	53,372	63,520	60,778	43,743	382,218
IGS-P	273,734	261,326	216,684	244,218	239,758	200,226	1,435,946
LGS-P-TOU	811,074	811,148	726,666	874,017	858,671	737,450	4,819,026
TOTAL PRIMARY	1,167,001	1,151,085	996,722	1,181,755	1,159,207	981,419	6,637,190
SECONDARY CLASSES:							
A & R	4,169,859	4,372,856	3,595,582	3,785,207	2,563,576	4,279,258	22,766,338
A-TOU & R-TOU	2,158,825	2,063,405	2,099,713	991,918	766,191	1,054,583	9,134,635
SGS	713,944	689,496	569,043	615,301	630,216	531,243	3,749,243
MGS-S	2,351,359	2,201,084	2,006,619	2,157,048	1,931,912	1,730,224	12,378,246
IGS-S	532,077	511,262	463,556	624,923	637,344	458,387	3,227,548
LGS-S-TOU	139,243	132,005	119,254	141,261	134,608	109,691	776,061
N	124	124	124	124	124	124	746
AL	20,815	0	20,815	20,793	0	20,793	83,217
SL	57,262	0	57,262	57,116	0	57,116	228,755
TOTAL SECONDARY	10,143,509	9,970,232	8,931,967	8,393,690	6,663,971	8,241,419	52,344,788
TOTAL COMPANY	11,310,510	11,121,316	9,928,689	9,575,446	7,823,178	9,222,838	58,981,978

[a] $58,981,978 distributed to periods and customer classes per NCP allocation on page 4. Where $58,981,978 equals: the subtotal of primary facilities marginal cost at the primary level [per page 1, line (3)].

Marginal Cost of Primary and Secondary Distribution Facilities
at Secondary Level

Proposed Rate Classes	WINTER On-Peak (1)	WINTER Interim (2)	WINTER Off-Peak (3)	OTHER On-Peak (4)	OTHER Interim (5)	OTHER Off-Peak (6)	Annual Cost (7)
ADDITIONAL COSTS OF PRIMARY FACILITIES FOR SECONDARY CLASSES: [a]							
A & R	144,716	151,761	124,786	131,367	88,970	148,513	790,114
A-TOU & R-TOU	74,923	71,611	72,871	34,425	26,591	36,600	317,021
SGS	24,778	23,929	19,749	21,354	21,872	18,437	130,119
MGS-S	81,605	76,389	69,640	74,861	67,048	60,048	429,591
IGS-S	18,466	17,744	16,088	21,688	22,119	15,908	112,013
LGS-S-TOU	4,832	4,581	4,139	4,903	4,672	3,807	26,933
N	4	4	4	4	4	4	26
AL	722	0	722	722	0	722	2,888
SL	1,987	0	1,987	1,982	0	1,982	7,939
SUBTOTAL	352,034	346,020	309,987	291,306	231,275	286,021	1,816,644
SECONDARY FACILITIES: [b]							
A & R	3,071,306	3,220,823	2,648,323	2,787,991	1,888,199	3,151,883	16,768,525
A-TOU & R-TOU	1,590,080	1,519,799	1,546,542	730,597	564,337	776,752	6,728,107
SGS	525,855	507,847	419,128	453,199	464,185	391,287	2,761,501
MGS-S	1,731,891	1,621,206	1,477,973	1,588,772	1,422,948	1,274,395	9,117,186
IGS-S	391,901	376,569	341,432	460,286	469,435	337,624	2,377,247
LGS-S-TOU	102,559	97,228	87,836	104,046	99,145	80,793	571,607
N	92	92	92	92	92	92	549
AL	15,331	0	15,331	15,315	0	15,315	61,293
SL	42,176	0	42,176	42,068	0	42,068	168,489
SUBTOTAL	7,471,192	7,343,565	6,578,832	6,182,365	4,908,342	6,070,209	38,554,505
TOTAL DISTRIBUTION COSTS FOR SECONDARY CLASSES [c]							
A & R	7,385,882	7,745,441	6,368,690	6,704,564	4,540,745	7,579,654	40,324,977
A-TOU & R-TOU	3,823,828	3,654,816	3,719,126	1,756,940	1,357,119	1,867,935	16,179,763
SGS	1,264,577	1,221,272	1,007,919	1,089,854	1,116,273	940,967	6,640,863
MGS-S	4,164,855	3,898,679	3,554,232	3,820,681	3,421,908	3,064,667	21,925,023
IGS-S	942,443	905,575	821,075	1,106,897	1,128,899	811,919	5,716,808
LGS-S-TOU	246,635	233,814	211,229	250,209	238,424	194,290	1,374,601
N	220	220	220	220	220	220	1,321
AL	36,869	0	36,869	36,830	0	36,830	147,398
SL	101,425	0	101,425	101,166	0	101,166	405,183
TOTAL	17,966,734	17,659,817	15,820,787	14,867,361	11,803,588	14,597,650	92,715,937

[a] $1,816,644 distributed to periods and customer classes per NCP allocation on page 5. Where $1,816,644 equals the additional cost to Secondary Classes for Primary facilities [per Page 1, line (6)].

[b] $38,554,505 distributed to periods and customer classes per NCP allocation on page 5. Where $38,554,505 equals the total cost of secondary facilities [per page 1, line (10)].

[c] Total costs of primary facilities (at primary level), plus additional primary facilities costs at Secondary level, plus Secondary costs.

Distribution of NCP Demands
(%) [a]

Proposed Rate Classes	WINTER On-Peak (1)	WINTER Interim (2)	WINTER Off-Peak (3)	OTHER On-Peak (4)	OTHER Interim (5)	OTHER Off-Peak (6)	Total (7)
PRIMARY CLASSES:							
MGS-P	0.1394%	0.1333%	0.0905%	0.1077%	0.1030%	0.0742%	0.6480%
IGS-P	0.4641%	0.4431%	0.3674%	0.4141%	0.4065%	0.3395%	2.4346%
LGS-P-TOU	1.3751%	1.3752%	1.2320%	1.4818%	1.4558%	1.2503%	8.1703%
TOTAL PRIMARY	1.9786%	1.9516%	1.6899%	2.0036%	1.9654%	1.6639%	11.2529%
SECONDARY CLASSES:							
A & R	7.0697%	7.4139%	6.0961%	6.4176%	4.3464%	7.2552%	38.5988%
A-TOU & R-TOU	3.6601%	3.4984%	3.5599%	1.6817%	1.2990%	1.7880%	15.4872%
SGS	1.2104%	1.1690%	0.9648%	1.0432%	1.0685%	0.9007%	6.3566%
MGS-S	3.9866%	3.7318%	3.4021%	3.6571%	3.2754%	2.9335%	20.9865%
IGS-S	0.9021%	0.8668%	0.7859%	1.0595%	1.0806%	0.7772%	5.4721%
LGS-S-TOU	0.2361%	0.2238%	0.2022%	0.2395%	0.2282%	0.1860%	1.3158%
N	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%	0.0013%
AL	0.0353%	0.0000%	0.0353%	0.0353%	0.0000%	0.0353%	0.1411%
SL	0.0971%	0.0000%	0.0971%	0.0968%	0.0000%	0.0968%	0.3878%
TOTAL SECONDARY	17.1976%	16.9039%	15.1436%	14.2309%	11.2983%	13.9728%	88.7471%
TOTAL COMPANY	19.1762%	18.8554%	16.8334%	16.2345%	13.2637%	15.6367%	100.0000%

[a] Calculated per Page 6.

Distribution of Secondary NCP Demands
(%) [a]

Proposed Rate Classes	WINTER On-Peak (1)	WINTER Interim (2)	WINTER Off-Peak (3)	OTHER On-Peak (4)	OTHER Interim (5)	OTHER Off-Peak (6)	Total (7)
SECONDARY CLASSES:							
A & R	7.9661%	8.3539%	6.8690%	7.2313%	4.8975%	8.1751%	43.4930%
A-TOU & R-TOU	4.1242%	3.9419%	4.0113%	1.8950%	1.4637%	2.0147%	17.4509%
SGS	1.3639%	1.3172%	1.0871%	1.1755%	1.2040%	1.0149%	7.1626%
MGS-S	4.4921%	4.2050%	3.8335%	4.1208%	3.6907%	3.3054%	23.6475%
IGS-S	1.0165%	0.9767%	0.8856%	1.1939%	1.2176%	0.8757%	6.1659%
LGS-S-TOU	0.2660%	0.2522%	0.2278%	0.2699%	0.2572%	0.2096%	1.4826%
N	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%	0.0014%
AL	0.0398%	0.0000%	0.0398%	0.0397%	0.0000%	0.0397%	0.1590%
SL	0.1094%	0.0000%	0.1094%	0.1091%	0.0000%	0.1091%	0.4370%
TOTAL SECONDARY	19.3783%	19.0472%	17.0637%	16.0354%	12.7309%	15.7445%	100.0000%

[a] calculated per page 6 for Secondary Classes.

Distribution of NCP Demands
(kW)

Proposed Rate Classes	WINTER On-Peak	WINTER Interim	WINTER Off-Peak	OTHER On-Peak	OTHER Interim	OTHER Off-Peak	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
PRIMARY CLASSES:							
MGS-P	11,242	10,752	7,300	8,688	8,313	5,983	52,278
IGS-P	37,440	35,743	29,637	33,403	32,793	27,386	196,402
LGS-P-TOU	110,935	110,945	99,390	119,544	117,445	100,865	659,124
TOTAL PRIMARY	159,617	157,440	136,327	161,635	158,551	134,234	907,804
SECONDARY CLASSES:							
A & R	570,334	598,099	491,787	517,723	350,634	585,297	3,113,874
A-TOU & R-TOU	295,274	282,223	287,189	135,670	104,796	144,241	1,249,393
SGS	97,650	94,306	77,831	84,158	86,198	72,661	512,804
MGS-S	321,608	301,054	274,456	295,031	264,238	236,652	1,693,039
IGS-S	72,775	69,928	63,403	85,474	87,173	62,696	441,449
LGS-S-TOU	19,045	18,055	16,311	19,321	18,411	15,003	106,146
N	17	17	17	17	17	17	102
AL	2,847	0	2,847	2,844	0	2,844	11,382
SL	7,832	0	7,832	7,812	0	7,812	31,288
TOTAL SECONDARY	1,387,382	1,363,682	1,221,673	1,148,050	911,467	1,127,223	7,159,477
TOTAL COMPANY	1,546,999	1,521,122	1,358,000	1,309,685	1,070,018	1,261,457	8,067,281

Source: Exhibit Maheu-20, Schedule 13, Page 6.

CENTRAL MAINE POWER COMPANY
CLASS CP'S WEIGHTED ON PROPABILITY OF PEAK
GENERATION

	CLASS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
PROBABILITY OF PEAK: [a]		50.500%	16.900%	6.300%	0.000%	0.000%	0.000%	0.000%	0.200%	0.400%	0.000%	1.800%	23.900%
CP'S: [b]	A&R	551,253	349,804	476,157	389,670	384,608	298,092	318,039	356,748	366,447	416,086	449,454	561,104
	A-TOU & R-T	245,415	238,466	155,862	95,079	85,024	35,330	40,236	48,404	51,862	81,047	115,033	179,850
	SGS	60,368	54,947	52,837	72,675	57,168	61,672	61,900	74,725	33,497	37,854	50,282	68,148
	MGS-SEC [c]	250,495	179,569	206,782	236,562	229,706	211,485	230,720	227,983	160,306	171,629	165,361	205,589
	MGS-PRI	6,192	7,519	8,973	7,065	7,061	7,494	6,817	6,847	5,158	5,535	5,742	6,619
	IGS-S	50,574	52,122	66,535	65,992	63,004	83,797	72,317	67,582	44,510	45,822	50,304	51,045
	IGS-P	25,172	27,331	35,017	25,926	24,579	28,845	24,760	31,273	24,438	22,852	25,999	24,773
	LGS-SEC	12,495	16,144	12,167	16,995	15,241	16,983	13,157	16,481	11,277	12,860	12,607	13,635
	LGS-PRI	90,589	93,775	85,022	95,286	94,956	104,132	92,540	105,237	87,870	82,791	80,189	86,657
	LGS-ST [c]	108,865	98,091	81,071	92,754	106,471	115,790	108,406	123,041	112,968	108,877	109,479	104,396
	LGS-T [c]	155,296	159,650	126,018	131,707	149,355	183,839	204,174	193,723	176,987	183,445	159,486	163,996
	GSS	0	0	1,152	1,184	2,080	0	0	0	0	0	0	7,050
	N	34	34	34	34	34	34	34	34	10	34	34	34
	AL	2,687	0	2,710	0	0	0	0	0	2,695	2,702	2,689	2,700
	SL	7,214	0	7,213	0	0	0	0	0	7,173	7,137	7,079	7,037
	W-1	21,244	18,684	18,883	16,756	15,734	14,712	16,108	16,603	14,875	15,980	17,055	20,043
	TOTAL	1,587,893	1,296,136	1,336,433	1,247,685	1,235,021	1,162,205	1,189,208	1,268,681	1,100,073	1,194,651	1,250,793	1,502,676

[a] Per Exhibit Maheu-6, Schedule 1, page 2, except as noted.
[b] Per Exhibit Maheu-20, Schedule 10, page 24.
[c] Per Page 7.

CENTRAL MAINE POWER COMPANY
CLASS CP'S WEIGHTED ON PROPABILITY OF PEAK
GENERATION

CLASS	JAN (1)	FEB (2)	MAR (3)	APR (4)	MAY (5)	JUN (6)	JUL (7)	AUG (8)	SEP (9)	OCT (10)	NOV (11)	DEC (12)	TOTAL (13)
WEIGHTED CP'S % [a]													
A&R	18.6369%	3.9577%	2.0083%	0.0000%	0.0000%	0.0000%	0.0000%	0.0478%	0.0981%	0.0000%	0.5416%	8.9778%	34.2682%
A-TOU & R-T	8.2970%	2.6980%	0.6574%	0.0000%	0.0000%	0.0000%	0.0000%	0.0065%	0.0139%	0.0000%	0.1386%	2.8777%	14.6891%
SGS	2.0409%	0.6217%	0.2228%	0.0000%	0.0000%	0.0000%	0.0000%	0.0100%	0.0090%	0.0000%	0.0606%	1.0904%	4.0554%
MGS-SEC	8.4688%	2.0317%	0.8721%	0.0000%	0.0000%	0.0000%	0.0000%	0.0305%	0.0429%	0.0000%	0.1993%	3.2895%	14.9348%
MGS-PRI	0.2093%	0.0851%	0.0378%	0.0000%	0.0000%	0.0000%	0.0000%	0.0009%	0.0014%	0.0000%	0.0069%	0.1059%	0.4474%
IGS-S	1.7098%	0.5897%	0.2806%	0.0000%	0.0000%	0.0000%	0.0000%	0.0090%	0.0119%	0.0000%	0.0606%	0.8167%	3.4785%
IGS-P	0.8510%	0.3092%	0.1477%	0.0000%	0.0000%	0.0000%	0.0000%	0.0042%	0.0065%	0.0000%	0.0313%	0.3964%	1.7464%
LGS-SEC	0.4224%	0.1827%	0.0513%	0.0000%	0.0000%	0.0000%	0.0000%	0.0022%	0.0030%	0.0000%	0.0152%	0.2182%	0.8950%
LGS-PRI	3.0627%	1.0610%	0.3586%	0.0000%	0.0000%	0.0000%	0.0000%	0.0141%	0.0235%	0.0000%	0.0966%	1.3865%	6.0030%
LGS-ST	3.6805%	1.1098%	0.3419%	0.0000%	0.0000%	0.0000%	0.0000%	0.0165%	0.0303%	0.0000%	0.1319%	1.6704%	6.9813%
LGS-T	5.2503%	1.8063%	0.5315%	0.0000%	0.0000%	0.0000%	0.0000%	0.0259%	0.0474%	0.0000%	0.1922%	2.6240%	10.4776%
GSS	0.0000%	0.0000%	0.0049%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.1128%	0.1177%
N	0.0011%	0.0004%	0.0001%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0005%	0.0023%
AL	0.0908%	0.0000%	0.0114%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0007%	0.0000%	0.0032%	0.0432%	0.1494%
SL	0.2439%	0.0000%	0.0304%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0019%	0.0000%	0.0085%	0.1126%	0.3974%
W-1	0.7182%	0.2114%	0.0796%	0.0000%	0.0000%	0.0000%	0.0000%	0.0022%	0.0040%	0.0000%	0.0206%	0.3207%	1.3567%
TOTAL	53.6838%	14.6645%	5.6366%	0.0000%	0.0000%	0.0000%	0.0000%	0.1699%	0.2946%	0.0000%	1.5073%	24.0433%	100.0000%

[a] Weighted percent distribution of customer class CP's based on page 1.

CENTRAL MAINE POWER COMPANY
CLASS CP'S WEIGHTED ON PROPABILITY OF PEAK
GENERATION

WEIGHTED CONRIBUTION TO 1988 PEAK [a]	
A&R	544,142
A-TOU & R-TOU	233,247
SGS	64,396
MGS-SEC	237,148
MGS-PRI	7,104
IGS-S	55,234
IGS-P	27,731
LGS-SEC	14,211
LGS-PRI	95,321
LGS-ST	110,855
LGS-T	166,373
GSS	1,868
N	36
AL	2,373
SL	6,310
	0
W-1	21,543
TOTAL	1,587,893

[a] Annual maximum coincident peak demand (1,587,893 kw) times POP weighted class contributions [page 2, column (13)]

CENTRAL MAINE POWER COMPANY
CLASS CP'S WEIGHTED ON PROPABILITY OF PEAK
TRANSMISSION

	CLASS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
PROBABILITY OF PEAK: [a]		44.100%	20.000%	8.300%	0.200%	0.000%	0.000%	0.000%	0.000%	0.100%	0.000%	2.000%	25.300%
CP'S: [b]	A&R	551,253	349,804	476,157	389,670	384,608	298,092	318,039	356,748	366,447	416,086	449,454	561,104
	A-TOU & R-T	245,415	238,466	155,862	95,079	85,024	35,330	40,236	48,404	51,862	81,047	115,033	179,850
	SGS	60,368	54,947	52,837	72,675	57,168	61,672	61,900	74,725	33,497	37,854	50,282	68,148
	MGS-SEC [c]	250,495	179,569	206,782	236,562	229,706	211,485	230,720	227,983	160,306	171,629	165,361	205,589
	MGS-PRI	6,192	7,519	8,973	7,065	7,061	7,494	6,817	6,847	5,158	5,535	5,742	6,619
	IGS-S	50,574	52,122	66,535	65,992	63,004	83,797	72,317	67,582	44,510	45,822	50,304	51,045
	IGS-P	25,172	27,331	35,017	25,926	24,579	28,845	24,760	31,273	24,438	22,852	25,999	24,773
	LGS-SEC	12,495	16,144	12,167	16,995	15,241	16,983	13,157	16,481	11,277	12,860	12,607	13,635
	LGS-PRI	90,589	93,775	85,022	95,286	94,956	104,132	92,540	105,237	87,870	82,791	80,189	86,657
	LGS-ST [c]	108,865	98,091	81,071	92,754	106,471	115,790	108,406	123,041	112,968	108,877	109,479	104,396
	LGS-T [c]	155,296	159,650	126,018	131,707	149,355	183,839	204,174	193,723	176,987	183,445	159,486	163,996
	GSS	0	0	1,152	1,184	2,080	0	0	0	0	0	0	7,050
	N	34	34	34	34	34	34	34	34	10	34	34	34
	AL	2,687	0	2,710	0	0	0	0	0	2,695	2,702	2,689	2,700
	SL	7,214	0	7,213	0	0	0	0	0	7,173	7,137	7,079	7,037
	W-1	21,244	18,684	18,883	16,756	15,734	14,712	16,108	16,603	14,875	15,980	17,055	20,043
	TOTAL	1,587,893	1,296,136	1,336,433	1,247,685	1,235,021	1,162,205	1,189,208	1,268,681	1,100,073	1,194,651	1,250,793	1,502,676

[a] Per Exhibit Maheu-6, Schedule 1, page 2, except as noted.
[b] Per Exhibit Maheu-20, Schedule 10, page 24.
[c] Per Page 7.

CENTRAL MAINE POWER COMPANY
CLASS CP'S WEIGHTED ON PROPABILITY OF PEAK
TRANSMISSION

CLASS	JAN (1)	FEB (2)	MAR (3)	APR (4)	MAY (5)	JUN (6)	JUL (7)	AUG (8)	SEP (9)	OCT (10)	NOV (11)	DEC (12)	TOTAL (13)
WEIGHTED CP'S % [a]													
A&R	16.4347%	4.7296%	2.6718%	0.0527%	0.0000%	0.0000%	0.0000%	0.0000%	0.0248%	0.0000%	0.6077%	9.5970%	34.1183%
A-TOU & R-T	7.3167%	3.2243%	0.8746%	0.0129%	0.0000%	0.0000%	0.0000%	0.0000%	0.0035%	0.0000%	0.1555%	3.0761%	14.6635%
SGS	1.7998%	0.7429%	0.2965%	0.0098%	0.0000%	0.0000%	0.0000%	0.0000%	0.0023%	0.0000%	0.0680%	1.1656%	4.0848%
MGS-SEC	7.4681%	2.4279%	1.1603%	0.0320%	0.0000%	0.0000%	0.0000%	0.0000%	0.0108%	0.0000%	0.2236%	3.5164%	14.8391%
MGS-PRI	0.1846%	0.1017%	0.0503%	0.0010%	0.0000%	0.0000%	0.0000%	0.0000%	0.0003%	0.0000%	0.0078%	0.1132%	0.4589%
IGS-S	1.5078%	0.7047%	0.3733%	0.0089%	0.0000%	0.0000%	0.0000%	0.0000%	0.0030%	0.0000%	0.0680%	0.8731%	3.5389%
IGS-P	0.7505%	0.3695%	0.1965%	0.0035%	0.0000%	0.0000%	0.0000%	0.0000%	0.0017%	0.0000%	0.0352%	0.4237%	1.7805%
LGS-SEC	0.3725%	0.2183%	0.0683%	0.0023%	0.0000%	0.0000%	0.0000%	0.0000%	0.0008%	0.0000%	0.0170%	0.2332%	0.9124%
LGS-PRI	2.7008%	1.2679%	0.4771%	0.0129%	0.0000%	0.0000%	0.0000%	0.0000%	0.0059%	0.0000%	0.1084%	1.4822%	6.0552%
LGS-ST	3.2456%	1.3263%	0.4549%	0.0125%	0.0000%	0.0000%	0.0000%	0.0000%	0.0076%	0.0000%	0.1480%	1.7856%	6.9806%
LGS-T	4.6299%	2.1586%	0.7071%	0.0178%	0.0000%	0.0000%	0.0000%	0.0000%	0.0120%	0.0000%	0.2156%	2.8050%	10.5460%
GSS	0.0000%	0.0000%	0.0065%	0.0002%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.1206%	0.1272%
N	0.0010%	0.0005%	0.0002%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0006%	0.0023%
AL	0.0801%	0.0000%	0.0152%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0002%	0.0000%	0.0036%	0.0462%	0.1453%
SL	0.2151%	0.0000%	0.0405%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0005%	0.0000%	0.0096%	0.1204%	0.3860%
W-1	0.6334%	0.2526%	0.1060%	0.0023%	0.0000%	0.0000%	0.0000%	0.0000%	0.0010%	0.0000%	0.0231%	0.3428%	1.3611%
TOTAL	47.3405%	17.5248%	7.4989%	0.1687%	0.0000%	0.0000%	0.0000%	0.0000%	0.0744%	0.0000%	1.6912%	25.7015%	100.0000%

[a] Weighted percent distribution of customer class CP's based on page 4.

CENTRAL MAINE POWER COMPANY
CLASS CP'S WEIGHTED ON PROPABILITY OF PEAK
TRANSMISSION

WEIGHTED CONRIBUTION TO 1988 PEAK [a]	
A&R	541,763
A-TOU & R-TOU	232,841
SGS	64,863
MGS-SEC	235,629
MGS-PRI	7,287
IGS-S	56,193
IGS-P	28,273
LGS-SEC	14,488
LGS-PRI	96,150
LGS-ST	110,844
LGS-T	167,459
GSS	2,020
N	36
AL	2,307
SL	6,129
	0
W-1	21,612
TOTAL	1,587,893

[a] Annual maximum coincident peak demand (1,587,893 kw) times POP weighted class contributions [page 5, column (13)]

INTERRUPTIBLE ADJUSTMENTS TO COINCIDENT PEAK DEMANDS
MGS-S, LGS-ST, AND LGS-T

RATE CLASS	Jan. 1/14 18:00	Feb. 2/9 8:00	Mar. 3/21 19:00	Apr. 4/7 9:00	May 5/2 9:00	Jun. 6/15 11:00	Jul. 7/11 11:00	Aug. 8/5 11:00	Sep. 9/29 20:00	Oct. 10/5 19:00	Nov. 11/21 18:00	Dec. 12/12 18:00
MGS-S CMP Proforma 1/	250,795	179,869	207,082	236,562	229,706	211,485	230,720	227,983	160,306	171,629	165,361	205,889
IR-CMP Adjustment 2/	<300>	<300>	<300>	--	--	--	--	--	--	--	--	<300>
Adjusted Total	250,495	179,569	206,782	236,562	229,706	211,485	230,720	227,983	160,306	171,629	165,361	205,589
LGS-ST CMP Proforma 1/	108,865	105,991	88,971	92,754	106,471	115,790	108,406	123,041	112,968	108,877	109,479	104,396
IR-CMP Adjustment 2/	--	<7,900>	<7,900>	--	--	--	--	--	--	--	--	--
Adjusted Total	108,865	98,091	81,071	92,754	106,471	115,790	108,406	123,041	112,968	108,877	109,479	104,396
LGS-T CMP Proforma 1/	155,296	183,650	150,018	131,707	149,355	183,839	204,174	193,723	176,987	183,445	159,486	163,996
IR-CMP Adjustment 2/	--	<24,000>	<24,000>	--	--	--	--	--	--	--	--	--
Adjusted Total	155,296	159,650	126,018	131,707	149,355	183,839	204,174	193,723	176,987	183,445	159,486	163,996

1/ Per Company figures in Schedule 10, Page 24 (updated TDAC).

2/ Contracted KW amount for those months in which IR-CMP customers can be interrupted (winter only); unless IR-CMP customers were actually interrupted at the time of the monthly peak, then adjustment equals zero. Per CMP response to BIW-03-15 and BIW-03-17.

CENTRAL MAINE POWER COMPANY
MARGINAL ENERGY COST BY COSTING PERIOD

		Winter			Other		
		On Peak	Interim	Off-Peak	On Peak	Interim	Off-Peak
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	Marginal Running Cost Including Variable O&M Expenses (1990 Mills per kWh) [a]	48.83	46.17	36.93	41.33	40.12	32.05
(2)	Cash Working Capital [a]	0.22	0.21	0.17	0.18	0.18	0.14
(3)	Revenue Requirements for Cash Working Capital (1990 Mills per kWh) (2) x 15.13% [b]	0.03	0.03	0.03	0.03	0.03	0.02
(4)	Marginal Energy Cost (1990 Mills per kWh) (1)+(3)	48.86	46.20	36.96	41.36	40.15	32.07
(5)	Marginal Energy Loss Factor for Secondary Service [a]	1.14564	1.12826	1.10688	1.12457	1.11980	1.09366
(6)	Marginal Energy Cost Including Losses for Secondary Service (1990 Mills per kWh)(4)x(5)	55.98	52.13	40.91	46.51	44.96	35.07
(7)	Marginal Energy Loss Factor for Primary Service [a]	1.10849	1.09572	1.07996	1.09301	1.08951	1.07017
(8)	Marginal Energy Cost Including Losses for Primary Service (1990 Mills per kWh)(4)x(7)	54.16	50.62	39.91	45.20	43.74	34.32
(9)	Marginal Energy Loss Factor for Subtrans-mission Service [a]	1.05843	1.05172	1.04337	1.05029	1.04843	1.03815
(10)	Marginal Energy Cost Including Losses for Subtransmission Service (1990 Mills per kWh)(4)x(9)	51.72	48.59	38.56	43.44	42.09	33.29
(11)	Marginal Energy Loss Factor for Transmission Service [a]	1.02558	1.02269	1.01907	1.02207	1.02127	1.01681
(12)	Marginal Energy Cost Including Losses for Transmission Service (1990 Mills per KWh) (4)x(11)	50.11	47.25	37.66	42.27	41.00	32.61

[a] Per Exhibit Maheu-25, Schedule 2.
[b] Includes overall return at 10.67 % and federal and state income tax component of 4.46 %. Overall return is using the stipulated capital structure and cost of capital. The income tax component is estimated at 0.398938/0.601062 of the preffed and common equity components.

EXHIBIT (BIW-2)
SCHEDULE 7
TABLE A

CENTRAL MAINE POWER COMPANY
DERIVATION OF ANNUAL ECONOMIC CHARGE
RELATED TO CAPITAL INVESTMENT

		(1)	(2)	(3)	(4)	(5)	(6)
			TRANSMISSION				
		GAS TURBINE [a]	345 kv [b]	Below 345 kv [c]	DISTRIBUTION [d]	METERING [e]	LIGHTING [f]
(1)	Present Value of Revenue Requirements Related to Incremental Investment	$1,332.33	$1,316.61	$1,310.94	$1,296.59	$1,310.45	$1,293.77
(2)	Present Value of Replacing Dispersed Retirements Related to Incremental Investmen	$0.00	$42.46	$52.86	$101.39	$68.34	$43.30
(3)	Total Present Value Related to Incremental Investment: (1) + (2)	$1,332.33	$1,359.07	$1,363.80	$1,397.98	$1,378.79	$1,337.07
(4)	Annual Economic Charge in Constant Dollars Related to Incremental Investment	$103.28	$94.36	$88.57	$94.71	$98.52	$138.94
(5)	Annual Economic Charge related to Incremental Investment: [(4)/$1,000]	10.33%	9.44%	8.86%	9.47%	9.85%	13.89%

[a] Per Table b, page 4.
[b] Average of 345 kv lines (Table C, page4); and 345 kv substations (Table C, page 8).
[c] Average of other trans. substation equip. (Table D, page 4); 115 kv poles (Table D, page 8); and trans. overhead conductors (Table D, page 12).
[d] Average of dist. poles (Table E, page 4); dist lines (Table E, page 8); and dist. transformers (Table E, page 12).
[e] Per Table F, page 4.
[f] Per Table G, page 4.

Exhibit____(BIW-2)
Schedule 7
Table B
Page 1 of 4

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	CUMBUSTION TURBINE
BOOK LIFE	25
IOWA CURVE	R
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	99.9930%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	1,000	40	0	0	1000	37.50	(1.00)	0	1,000.00	57.10	49.61	97.49	38.89	16.50	201.10	0.948764	
2	1,000	40	0	40	960	72.18	12.84	(1.00)	961.00	54.87	47.67	59.11	23.58	16.50	195.46	0.916334	
3	1,000	40	0	80	920	66.77	10.68	11.84	908.16	51.85	45.05	59.49	23.73	16.50	187.81	0.877164	
4	1,000	40	0	120	880	61.76	8.68	22.52	857.48	48.96	42.54	59.69	23.81	16.50	180.49	0.839668	
5	1,000	40	0	160	840	57.13	6.83	31.20	808.80	46.18	40.12	59.69	23.81	16.50	173.44		
6	1,000	40	0	200	800	52.84	5.12	38.03	761.97	43.50	37.80	59.53	23.75	16.50	166.67		
7	1,000	40	0	240	760	48.88	3.54	43.15	716.85	40.93	35.56	59.21	23.62	16.50	160.15		
8	1,000	40	0	280	720	45.21	2.08	46.69	673.31	38.44	33.40	58.75	23.44	16.50	153.86		
9	1,000	40	0	320	680	44.61	1.84	48.77	631.23	36.04	31.31	55.35	22.08	16.50	147.77		
10	1,000	40	0	360	640	44.61	1.84	50.61	589.39	33.65	29.24	51.38	20.50	16.50	141.73		
11	1,000	40	0	400	600	44.61	1.84	52.45	547.55	31.26	27.16	47.40	18.91	16.50	135.67		
12	1,000	40	0	440	560	44.61	1.84	54.29	505.71	28.87	25.09	43.42	17.32	16.50	129.62		
13	1,000	40	0	480	520	44.61	1.84	56.13	463.87	26.48	23.01	39.45	15.74	16.50	123.57		
14	1,000	40	0	520	480	44.61	1.84	57.97	422.03	24.10	20.94	35.49	14.16	16.50	117.54		
15	1,000	40	0	560	440	44.61	1.84	59.81	380.19	21.71	18.86	31.51	12.57	16.50	111.48		
16	1,000	40	0	600	400	44.61	1.84	61.65	338.35	19.32	16.78	27.53	10.98	16.50	105.42		
17	1,000	40	0	640	360	44.61	1.84	63.49	296.51	16.93	14.71	23.56	9.40	16.50	99.38		
18	1,000	40	0	680	320	44.61	1.84	65.33	254.67	14.54	12.63	19.58	7.81	16.50	93.32		
19	1,000	40	0	720	280	44.61	1.84	67.17	212.83	12.15	10.56	15.61	6.23	16.50	87.28		
20	1,000	40	0	760	240	44.61	1.84	69.01	170.99	9.76	8.48	11.63	4.64	16.50	81.22		
21	1,000	40	0	800	200	22.31	(7.06)	70.85	129.15	7.37	6.41	29.95	11.95	16.50	75.17		
22	1,000	40	0	840	160	0	(15.96)	63.79	96.21	5.49	4.77	49.13	19.60	16.50	70.40		

23	1,000	40	0	880	120	0	(15.96)	47.83	72.17	4.12	3.58	46.85	18.69	16.50	66.93
24	1,000	40	0	920	80	0	(15.96)	31.87	48.13	2.75	2.39	44.57	17.78	16.50	63.46
25	1,000	40	1000	960	40	0	(15.91)	15.91	24.09	1.38	1.20	42.37	16.90	16.50	60.07
26	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
27	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
28	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
29	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
30	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
31	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
32	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
33	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
34	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
35	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
36	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
37	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
38	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
39	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
40	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
41	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
42	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
43	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
44	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
45	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
46	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
47	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
48	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
49	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
50	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
51	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
52	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
53	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
54	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
55	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
56	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
57	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
58	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
59	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
60	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
61	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
62	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
63	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
64	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
65	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
66	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
67	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
68	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
69	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
70	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
71	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
72	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
73	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
74	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
75	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
76	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
77	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
78	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00

79	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
80	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
81	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
82	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
83	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
84	0	0	0	0	0	0	0.00	0.00	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00
PRESENT VALUE															1,332.33

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,332.33
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	0
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,332.33
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	103.28
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	10.33%

Exhibit ___ (BIW-2)
Schedule 7
Table C

6.66H

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	TRANSMISSION (345 KV LINES)
BOOK LIFE	30
IOWA CURVE	2.5
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	999	33.30	2	0.00	999.00	37.70	1.76	0	999.00	57.04	49.56	90.51	36.11	16.48	194.25	0.948764	1.48
2	997	33.23	2	31.30	965.70	72.58	15.70	1.76	963.94	55.04	47.82	52.23	20.84	16.45	189.08	0.900153	1.39
3	995	33.17	3	62.53	932.47	67.13	13.55	17.46	915.01	52.24	45.39	52.95	21.12	16.42	181.89	0.854032	1.94
4	992	33.07	3	92.70	899.30	62.1	11.58	31.01	868.29	49.58	43.07	53.45	21.32	16.37	174.99	0.810275	1.81
5	989	32.97	4	122.77	866.23	57.44	9.76	42.59	823.64	47.03	40.86	53.77	21.45	16.32	168.39	0.768760	2.25
6	985	32.83	4	151.73	833.27	53.13	8.10	52.35	780.92	44.59	38.74	53.89	21.50	16.25	162.01	0.729372	2.09
7	981	32.70	4	180.57	800.43	49.15	6.56	60.45	739.98	42.25	36.71	53.84	21.48	16.19	155.89	0.692002	1.94
8	977	32.57	5	209.27	767.73	45.46	5.14	67.01	700.72	40.01	34.76	53.67	21.41	16.12	150.01	0.656546	2.25
9	972	32.40	6	236.83	735.17	44.86	4.97	72.15	663.02	37.85	32.89	50.51	20.15	16.04	144.30	0.622907	2.50
10	966	32.20	7	263.23	702.77	44.86	5.05	77.12	625.65	35.72	31.04	46.77	18.66	15.94	138.61	0.590992	2.69
11	959	31.97	7	288.43	670.57	44.86	5.14	82.17	588.40	33.59	29.19	42.99	17.15	15.82	132.86	0.560712	2.48
12	952	31.73	9	313.40	638.60	44.86	5.24	87.31	551.29	31.48	27.35	39.25	15.66	15.71	127.17	0.531983	2.93
13	943	31.43	9	336.13	606.87	44.86	5.36	92.55	514.32	29.36	25.51	35.43	14.13	15.56	121.35	0.504727	2.68
14	934	31.13	10	358.57	575.43	44.86	5.48	97.91	477.52	27.26	23.69	31.63	12.62	15.41	115.59	0.478867	2.72
15	924	30.80	12	379.70	544.30	44.86	5.61	103.39	440.91	25.17	21.87	27.82	11.10	15.25	109.80	0.454331	2.97
16	912	30.40	13	398.50	513.50	44.86	5.77	109.00	404.50	23.09	20.07	23.96	9.56	15.05	103.94	0.431053	2.92
17	899	29.97	14	415.90	483.10	44.86	5.94	114.77	368.33	21.03	18.27	20.09	8.01	14.83	98.05	0.408968	2.84
18	885	29.50	16	431.87	453.13	44.86	6.13	120.71	332.42	18.98	16.49	16.22	6.47	14.60	92.17	0.388014	2.91
19	869	28.97	17	445.37	423.63	44.86	6.34	126.84	296.79	16.95	14.72	12.31	4.91	14.34	86.23	0.368134	2.75
20	852	28.40	19	457.33	394.67	44.86	6.57	133.18	261.49	14.93	12.97	8.39	3.35	14.06	80.28	0.349272	2.71
21	833	27.77	21	466.73	366.27	22.43	(2.13)	139.75	226.52	12.93	11.24	26.85	10.71	13.74	74.26	0.331377	2.62
22	812	27.07	23	473.50	338.50	0	(10.80)	137.62	200.88	11.47	9.97	46.15	18.41	13.40	69.52	0.314398	2.48

23	789	26.30	25	477.57	311.43	0	(10.49)	126.82	184.61	10.54	9.16	43.84	17.49	13.02	66.02	0.298290	2.30
24	764	25.47	27	478.87	285.13	0	(10.16)	116.33	168.80	9.64	8.37	41.50	16.56	12.61	62.49	0.283006	2.07
25	737	24.57	30	477.33	259.67	0	(9.80)	106.17	153.50	8.76	7.61	39.14	15.61	12.16	58.91	0.268506	1.86
26	707	23.57	32	471.90	235.10	0	(9.40)	96.37	138.73	7.92	6.88	36.75	14.66	11.67	55.30	0.254749	1.55
27	675	22.50	35	463.47	211.53	0	(8.98)	86.97	124.56	7.11	6.18	34.32	13.69	11.14	51.64	0.241697	1.23
28	640	21.33	37	450.97	189.03	0	(8.51)	77.99	111.04	6.34	5.51	31.88	12.72	10.56	47.95	0.229313	0.85
29	603	20.10	39	435.30	167.70	0	(8.02)	69.48	98.22	5.61	4.87	29.43	11.74	9.95	44.25	0.217564	0.43
30	564	18.80	41	416.40	147.60	0	(7.50)	61.46	86.14	4.92	4.27	26.99	10.77	9.31	40.57	0.206417	0.00
31	523	17.43	42	394.20	128.80	0	(6.95)	53.96	74.84	4.27	3.71	24.55	9.79	8.63	36.88	0.195841	(0.44)
32	481	16.03	44	369.63	111.37	0	(6.40)	47.01	64.36	3.67	3.19	22.13	8.83	7.94	33.26	0.185807	(0.91)
33	437	14.57	44	341.67	95.33	0	(5.81)	40.61	54.72	3.12	2.71	19.76	7.88	7.21	29.68	0.176287	(1.33)
34	393	13.10	43	312.23	80.77	0	(5.23)	34.80	45.97	2.62	2.28	17.45	6.96	6.48	26.21	0.167255	(1.68)
35	350	11.67	43	282.33	67.67	0	(4.65)	29.57	38.10	2.18	1.89	15.30	6.10	5.78	22.97	0.158685	(2.05)
36	307	10.23	41	251.00	56.00	0	(4.08)	24.92	31.08	1.77	1.54	13.18	5.26	5.07	19.79	0.150555	(2.29)
37	266	8.87	38	220.23	45.77	0	(3.54)	20.84	24.93	1.42	1.24	11.22	4.48	4.39	16.86	0.142841	(2.42)
38	228	7.60	35	191.10	36.90	0	(3.03)	17.30	19.60	1.12	0.97	9.47	3.78	3.76	14.20	0.135522	(2.48)
39	193	6.43	32	163.70	29.30	0	(2.57)	14.27	15.03	0.86	0.75	7.86	3.14	3.18	11.79	0.128579	(2.49)
40	161	5.37	29	138.13	22.87	0	(2.14)	11.70	11.17	0.64	0.55	6.43	2.57	2.66	9.65	0.121991	(2.45)
41	132	4.40	25	114.50	17.50	0	(1.76)	9.56	7.94	0.45	0.39	5.14	2.05	2.18	7.71	0.115740	(2.27)
42	107	3.57	22	93.90	13.10	0	(1.42)	7.80	5.30	0.30	0.26	4.07	1.62	1.77	6.10	0.109810	(2.13)
43	85	2.83	19	75.47	9.53	0	(1.13)	6.38	3.15	0.18	0.16	3.13	1.25	1.40	4.69	0.104184	(1.94)
44	66	2.20	15	59.30	6.70	0	(0.88)	5.25	1.45	0.08	0.07	2.33	0.93	1.09	3.49	0.098846	(1.61)
45	51	1.70	13	46.50	4.50	0	(0.68)	4.37	0.13	0.01	0.01	1.71	0.68	0.84	2.56	0.093782	(1.46)
46	38	1.27	10	35.20	2.80	0	(0.51)	3.69	(0.89)	(0.05)	(0.04)	1.18	0.47	0.63	1.77	0.088976	(1.17)
47	28	0.93	8	26.47	1.53	0	(0.37)	3.18	(1.65)	(0.09)	(0.08)	0.79	0.32	0.46	1.17	0.084418	(0.98)
48	20	0.67	7	19.40	0.60	0	(0.27)	2.81	(2.21)	(0.13)	(0.11)	0.44	0.18	0.33	0.67	0.080092	(0.88)
49	13	0.43	4	13.07	(0.07)	0	(0.17)	2.54	(2.61)	(0.15)	(0.13)	0.19	0.08	0.21	0.27	0.075989	(0.52)
50	9	0.30	4	9.50	(0.50)	0	(0.12)	2.37	(2.87)	(0.16)	(0.14)	0.03	0.01	0.15	0.04	0.072095	(0.54)
51	5	0.17	2	5.80	(0.80)	0	(0.07)	2.25	(3.05)	(0.17)	(0.15)	(0.12)	(0.05)	0.08	(0.19)	0.068402	(0.28)
52	3	0.10	2	3.97	(0.97)	0	(0.04)	2.18	(3.15)	(0.18)	(0.16)	(0.20)	(0.08)	0.05	(0.31)	0.064897	(0.28)
53	1	0.03	0	2.07	(1.07)	0	(0.01)	2.14	(3.21)	(0.18)	(0.16)	(0.26)	(0.10)	0.02	(0.40)	0.061572	0.00
54	1	0.03	1	2.10	(1.10)	0	(0.01)	2.13	(3.23)	(0.18)	(0.16)	(0.26)	(0.10)	0.02	(0.40)	0.058417	(0.15)
55	0	0.00	0	1.13	(1.13)	0	0.00	2.12	(3.25)	(0.19)	(0.16)	(0.32)	(0.13)	0.00	(0.48)	0.055424	0.00
56	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.052584	0.00
57	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.049890	0.00
58	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.047334	0.00
59	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.044909	0.00
60	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.042608	0.00
61	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.040425	0.00
62	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.038353	0.00
63	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.036388	0.00
64	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.034524	0.00
65	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.032755	0.00
66	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.031077	0.00
67	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.029484	0.00
68	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.027974	0.00
69	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.026540	0.00
70	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.025181	0.00
71	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.023890	0.00
72	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.022666	0.00
73	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.021505	0.00
74	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.020403	0.00
75	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.019358	0.00
76	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.018366	0.00
77	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00
														P.V. OF REV. RQMT	1,318.22	SUM OF	30.92

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,318.22
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	40.75
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,358.98
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	97.10
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	9.71%

Exhibit ___ (BIW-2)
Schedule 7
Table C

6.66H

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	TRANSMISSION (345 KV SUBSTATIONS)		
BOOK LIFE	35		
IOWA CURVE	2.5		
TAX LIFE	20		
INCOME TAX RATE	39.8938%		
P. TAX,INS.A&G	1.6500%		
TAX BASIS	100.5400%		
COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	999	28.54	1	0.00	999.00	37.70	3.65	0	999.00	57.04	49.56	85.74	34.20	16.48	189.47	0.948764	0.79
2	998	28.51	2	27.54	970.46	72.58	17.58	3.65	966.81	55.20	47.96	47.77	19.06	16.47	184.78	0.900153	1.48
3	996	28.46	3	54.06	941.94	67.13	15.43	21.23	920.71	52.57	45.67	48.79	19.46	16.43	178.02	0.854032	2.09
4	993	28.37	2	79.51	913.49	62.1	13.46	36.66	876.83	50.06	43.50	49.56	19.77	16.38	171.54	0.810275	1.30
5	991	28.31	3	105.89	885.11	57.44	11.62	50.12	834.99	47.67	41.42	50.18	20.02	16.35	165.39	0.768760	1.83
6	988	28.23	3	131.20	856.80	53.13	9.93	61.74	795.06	45.39	39.44	50.61	20.19	16.30	159.48	0.729372	1.71
7	985	28.14	3	156.43	828.57	49.15	8.38	71.67	756.90	43.22	37.55	50.90	20.31	16.25	153.85	0.692002	1.60
8	982	28.06	4	181.57	800.43	45.46	6.94	80.05	720.38	41.13	35.74	51.02	20.35	16.20	148.42	0.656546	1.99
9	978	27.94	4	205.63	772.37	44.86	6.75	86.99	685.38	39.13	34.00	48.19	19.22	16.14	143.18	0.622907	1.86
10	974	27.83	5	229.57	744.43	44.86	6.79	93.74	650.69	37.15	32.28	44.77	17.86	16.07	137.98	0.590992	2.16
11	969	27.69	6	252.40	716.60	44.86	6.85	100.53	616.07	35.17	30.56	41.34	16.49	15.99	132.75	0.560712	2.41
12	963	27.51	5	274.09	688.91	44.86	6.92	107.38	581.53	33.20	28.85	37.89	15.12	15.89	127.49	0.531983	1.87
13	958	27.37	7	296.60	661.40	44.86	6.98	114.30	547.10	31.24	27.14	34.49	13.76	15.81	122.30	0.504727	2.42
14	951	27.17	7	316.97	634.03	44.86	7.06	121.28	512.75	29.28	25.44	31.03	12.38	15.69	117.02	0.478867	2.24
15	944	26.97	8	337.14	606.86	44.86	7.14	128.34	478.52	27.32	23.74	27.57	11.00	15.58	111.75	0.454331	2.37
16	936	26.74	8	356.11	579.89	44.86	7.23	135.48	444.41	25.37	22.05	24.10	9.61	15.44	106.44	0.431053	2.18
17	928	26.51	10	374.86	553.14	44.86	7.32	142.71	410.43	23.43	20.36	20.64	8.23	15.31	101.16	0.408968	2.50
18	918	26.23	10	391.37	526.63	44.86	7.43	150.03	376.60	21.50	18.68	17.13	6.83	15.15	95.82	0.388014	2.29
19	908	25.94	12	407.60	500.40	44.86	7.55	157.46	342.94	19.58	17.01	13.66	5.45	14.98	90.51	0.368134	2.51
20	896	25.60	12	421.54	474.46	44.86	7.68	165.01	309.45	17.67	15.35	10.13	4.04	14.78	85.12	0.349272	2.29
21	884	25.26	14	435.14	448.86	22.43	(1.13)	172.69	276.17	15.77	13.70	29.06	11.59	14.59	79.78	0.331377	2.42
22	870	24.86	14	446.40	423.60	0	(9.92)	171.56	252.04	14.39	12.50	48.79	19.46	14.36	75.65	0.314398	2.18

23	856	24.46	16	457.26	398.74	0	(9.76)	161.64	237.10	13.54	11.76	46.98	18.74	14.12	72.86	0.298290	2.23
24	840	24.00	17	465.71	374.29	0	(9.57)	151.88	222.41	12.70	11.03	45.14	18.01	13.86	70.03	0.283006	2.11
25	823	23.51	19	472.71	350.29	0	(9.38)	142.31	207.98	11.87	10.32	43.26	17.26	13.58	67.16	0.268506	2.09
26	804	22.97	20	477.23	326.77	0	(9.16)	132.93	193.84	11.07	9.62	41.40	16.52	13.27	64.29	0.254749	1.92
27	784	22.40	22	480.20	303.80	0	(8.94)	123.77	180.03	10.28	8.93	39.50	15.76	12.94	61.37	0.241697	1.83
28	762	21.77	23	480.60	281.40	0	(8.69)	114.83	166.57	9.51	8.26	37.59	15.00	12.57	58.42	0.229313	1.62
29	739	21.11	26	479.37	259.63	0	(8.42)	106.14	153.49	8.76	7.61	35.69	14.24	12.19	55.49	0.217564	1.53
30	713	20.37	27	474.49	238.51	0	(8.13)	97.72	140.79	8.04	6.98	33.74	13.46	11.76	52.48	0.206417	1.29
31	686	19.60	28	467.86	218.14	0	(7.82)	89.59	128.55	7.34	6.38	31.81	12.69	11.32	49.51	0.195841	1.04
32	658	18.80	31	459.46	198.54	0	(7.50)	81.77	116.77	6.67	5.79	29.90	11.93	10.86	46.55	0.185807	0.84
33	627	17.91	32	447.26	179.74	0	(7.15)	74.27	105.47	6.02	5.23	27.92	11.14	10.35	43.50	0.176287	0.56
34	595	17.00	34	433.17	161.83	0	(6.78)	67.12	94.71	5.41	4.70	26.00	10.37	9.82	40.52	0.167255	0.29
35	561	16.03	35	416.17	144.83	0	(6.39)	60.34	84.49	4.82	4.19	24.06	9.60	9.26	37.51	0.158685	0.00
36	526	15.03	36	397.20	128.80	0	(6.00)	53.95	74.85	4.27	3.71	22.13	8.83	8.68	34.52	0.150555	(0.29)
37	490	14.00	37	376.23	113.77	0	(5.59)	47.95	65.82	3.76	3.27	20.25	8.08	8.09	31.61	0.142841	(0.59)
38	453	12.94	38	353.23	99.77	0	(5.16)	42.36	57.41	3.28	2.85	18.41	7.34	7.47	28.72	0.135522	(0.88)
39	415	11.86	37	328.17	86.83	0	(4.73)	37.20	49.63	2.83	2.46	16.57	6.61	6.85	25.88	0.128579	(1.11)
40	378	10.80	38	303.03	74.97	0	(4.31)	32.47	42.50	2.43	2.11	14.84	5.92	6.24	23.19	0.121991	(1.39)
41	340	9.71	36	275.83	64.17	0	(3.88)	28.16	36.01	2.06	1.79	13.13	5.24	5.61	20.53	0.115740	(1.55)
42	304	8.69	35	249.54	54.46	0	(3.47)	24.28	30.18	1.72	1.50	11.54	4.60	5.02	18.06	0.109810	(1.71)
43	269	7.69	33	223.23	45.77	0	(3.07)	20.81	24.96	1.43	1.24	10.06	4.01	4.44	15.74	0.104184	(1.80)
44	236	6.74	31	197.91	38.09	0	(2.69)	17.74	20.35	1.16	1.01	8.67	3.46	3.89	13.57	0.098846	(1.86)
45	205	5.86	29	173.66	31.34	0	(2.34)	15.05	16.29	0.93	0.81	7.40	2.95	3.38	11.59	0.093782	(1.88)
46	176	5.03	26	150.51	25.49	0	(2.01)	12.71	12.78	0.73	0.63	6.24	2.49	2.90	9.77	0.088976	(1.81)
47	150	4.29	24	129.54	20.46	0	(1.71)	10.70	9.76	0.56	0.48	5.22	2.08	2.48	8.18	0.084418	(1.78)
48	126	3.60	21	109.83	16.17	0	(1.44)	8.99	7.18	0.41	0.36	4.28	1.71	2.08	6.72	0.080092	(1.65)
49	105	3.00	19	92.43	12.57	0	(1.20)	7.55	5.02	0.29	0.25	3.48	1.39	1.73	5.46	0.075989	(1.57)
50	86	2.46	16	76.43	9.57	0	(0.98)	6.35	3.22	0.18	0.16	2.76	1.10	1.42	4.34	0.072095	(1.39)
51	70	2.00	14	62.89	7.11	0	(0.80)	5.37	1.74	0.10	0.09	2.16	0.86	1.16	3.41	0.068402	(1.26)
52	56	1.60	12	50.89	5.11	0	(0.64)	4.57	0.54	0.03	0.03	1.65	0.66	0.92	2.60	0.064897	(1.13)
53	44	1.26	10	40.49	3.51	0	(0.50)	3.93	(0.42)	(0.02)	(0.02)	1.23	0.49	0.73	1.94	0.061572	(0.97)
54	34	0.97	8	31.74	2.26	0	(0.39)	3.43	(1.17)	(0.07)	(0.06)	0.85	0.34	0.56	1.35	0.058417	(0.80)
55	26	0.74	7	24.71	1.29	0	(0.30)	3.04	(1.75)	(0.10)	(0.09)	0.57	0.23	0.43	0.91	0.055424	(0.72)
56	19	0.54	5	18.46	0.54	0	(0.22)	2.74	(2.20)	(0.13)	(0.11)	0.32	0.13	0.31	0.52	0.052584	(0.53)
57	14	0.40	4	14.00	(0.00)	0	(0.16)	2.52	(2.52)	(0.14)	(0.13)	0.17	0.07	0.23	0.27	0.049890	(0.44)
58	10	0.29	3	10.40	(0.40)	0	(0.11)	2.36	(2.76)	(0.16)	(0.14)	0.03	0.01	0.17	0.06	0.047334	(0.33)
59	7	0.20	3	7.69	(0.69)	0	(0.08)	2.25	(2.94)	(0.17)	(0.15)	(0.08)	(0.03)	0.12	(0.11)	0.044909	(0.34)
60	4	0.11	2	4.89	(0.89)	0	(0.05)	2.17	(3.06)	(0.17)	(0.15)	(0.18)	(0.07)	0.07	(0.26)	0.042608	(0.23)
61	2	0.06	0	3.00	(1.00)	0	(0.02)	2.12	(3.12)	(0.18)	(0.15)	(0.24)	(0.10)	0.03	(0.36)	0.040425	0.00
62	2	0.06	0	3.06	(1.06)	0	(0.02)	2.10	(3.16)	(0.18)	(0.16)	(0.24)	(0.10)	0.03	(0.37)	0.038353	0.00
63	2	0.06	2	3.11	(1.11)	0	(0.02)	2.08	(3.19)	(0.18)	(0.16)	(0.24)	(0.10)	0.03	(0.37)	0.036388	(0.24)
64	0	0.00	0	1.17	(1.17)	0	0.00	2.06	(3.23)	(0.18)	(0.16)	(0.30)	(0.12)	0.00	(0.46)	0.034524	0.00
65	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.032755	0.00
66	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.031077	0.00
67	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.029484	0.00
68	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.027974	0.00
69	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.026540	0.00
70	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.025181	0.00
71	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.023890	0.00
72	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.022666	0.00
73	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.021505	0.00
74	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.020403	0.00
75	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.019358	0.00
76	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.018366	0.00
77	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00

P.V. OF REV. RQMT 1,315.00 SUM OF 33.59

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,315.00
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	44.17
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,359.17
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	91.61
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	9.16%

Exhibit ___ (BIW-2)
Schedule 7
Table D

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	TRANSMISSION (OTHER TRNS SUBSTATION EQMT)
BOOK LIFE	42
IOWA CURVE	1
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	997	23.74	6	0.00	997.00	37.70	5.57	0	997.00	56.92	49.46	80.74	32.21	16.45	184.35	0.948764	5.03
2	991	23.60	7	17.74	973.26	72.58	19.54	5.57	967.69	55.25	48.01	42.93	17.13	16.35	179.88	0.900153	5.53
3	984	23.43	7	34.33	949.67	67.13	17.43	25.11	924.56	52.79	45.87	44.12	17.60	16.24	173.36	0.854032	5.21
4	977	23.26	6	50.76	926.24	62.1	15.49	42.54	883.70	50.45	43.84	45.09	17.99	16.12	167.15	0.810275	4.20
5	971	23.12	8	68.02	902.98	57.44	13.69	58.03	844.95	48.24	41.92	45.93	18.32	16.02	161.31	0.768760	5.27
6	963	22.93	7	83.14	879.86	53.13	12.05	71.72	808.14	46.14	40.09	46.57	18.58	15.89	155.68	0.729372	4.34
7	956	22.76	7	99.07	856.93	49.15	10.53	83.77	773.16	44.14	38.35	47.05	18.77	15.77	150.32	0.692002	4.08
8	949	22.60	8	114.83	834.17	45.46	9.12	94.30	739.87	42.24	36.70	47.41	18.91	15.66	145.23	0.656546	4.37
9	941	22.40	8	129.43	811.57	44.86	8.96	103.42	708.15	40.43	35.13	44.81	17.88	15.53	140.33	0.622907	4.10
10	933	22.21	8	143.83	789.17	44.86	9.03	112.38	676.79	38.64	33.57	41.63	16.61	15.39	135.45	0.590992	3.85
11	925	22.02	9	158.05	766.95	44.86	9.11	121.41	645.54	36.86	32.02	38.49	15.36	15.26	130.63	0.560712	4.06
12	916	21.81	8	171.07	744.93	44.86	9.20	130.52	614.41	35.08	30.48	35.32	14.09	15.11	125.77	0.531983	3.38
13	908	21.62	9	184.88	723.12	44.86	9.27	139.72	583.40	33.31	28.94	32.17	12.83	14.98	120.95	0.504727	3.55
14	899	21.40	9	197.50	701.50	44.86	9.36	148.99	552.51	31.55	27.41	29.04	11.59	14.83	116.14	0.478867	3.32
15	890	21.19	9	209.90	680.10	44.86	9.44	158.35	521.75	29.79	25.88	25.89	10.33	14.69	111.32	0.454331	3.10
16	881	20.98	9	222.10	658.90	44.86	9.53	167.79	491.11	28.04	24.36	22.77	9.08	14.54	106.53	0.431053	2.89
17	872	20.76	10	234.07	637.93	44.86	9.61	177.32	460.61	26.30	22.85	19.65	7.84	14.39	101.75	0.408968	2.99
18	862	20.52	10	244.83	617.17	44.86	9.71	186.93	430.24	24.56	21.34	16.53	6.59	14.22	96.94	0.388014	2.78
19	852	20.29	10	255.36	596.64	44.86	9.80	196.64	400.00	22.84	19.84	13.42	5.35	14.06	92.18	0.368134	2.58
20	842	20.05	10	265.64	576.36	44.86	9.90	206.44	369.92	21.12	18.35	10.33	4.12	13.89	87.43	0.349272	2.39
21	832	19.81	11	275.69	556.31	22.43	1.05	216.34	339.97	19.41	16.87	29.68	11.84	13.73	82.71	0.331377	2.44
22	821	19.55	11	284.50	536.50	0	(7.80)	217.39	319.11	18.22	15.83	49.86	19.89	13.55	79.24	0.314398	2.25

23	810	19.29	11	293.05	516.95	0	(7.69)	209.59	307.36	17.55	15.25	48.49	19.34	13.37	77.11	0.298290	2.07
24	799	19.02	11	301.33	497.67	0	(7.59)	201.90	295.77	16.89	14.67	47.12	18.80	13.18	74.97	0.283006	1.91
25	788	18.76	12	309.36	478.64	0	(7.48)	194.31	284.33	16.23	14.11	45.77	18.26	13.00	72.88	0.268506	1.90
26	776	18.48	12	316.12	459.88	0	(7.37)	186.83	273.05	15.59	13.55	44.42	17.72	12.80	70.77	0.254749	1.74
27	764	18.19	13	322.60	441.40	0	(7.26)	179.46	261.94	14.96	12.99	43.07	17.18	12.61	68.67	0.241697	1.71
28	751	17.88	13	327.79	423.21	0	(7.13)	172.20	251.01	14.33	12.45	41.73	16.65	12.39	66.57	0.229313	1.55
29	738	17.57	13	332.67	405.33	0	(7.01)	165.07	240.26	13.72	11.92	40.40	16.12	12.18	64.50	0.217564	1.40
30	725	17.26	14	337.24	387.76	0	(6.89)	158.06	229.70	13.11	11.40	39.07	15.59	11.96	62.43	0.206417	1.35
31	711	16.93	14	340.50	370.50	0	(6.75)	151.17	219.33	12.52	10.88	37.76	15.06	11.73	60.37	0.195841	1.20
32	697	16.60	14	343.43	353.57	0	(6.62)	144.42	209.15	11.94	10.38	36.46	14.55	11.50	58.35	0.185807	1.06
33	683	16.26	15	346.02	336.98	0	(6.49)	137.80	199.18	11.37	9.88	35.17	14.03	11.27	56.32	0.176287	1.00
34	668	15.90	15	347.29	320.71	0	(6.35)	131.31	189.40	10.81	9.40	33.88	13.52	11.02	54.30	0.167255	0.86
35	653	15.55	16	348.19	304.81	0	(6.20)	124.96	179.85	10.27	8.92	32.64	13.02	10.77	52.33	0.158685	0.78
36	637	15.17	15	347.74	289.26	0	(6.05)	118.76	170.50	9.73	8.46	31.36	12.51	10.51	50.33	0.150555	0.61
37	622	14.81	16	347.90	274.10	0	(5.91)	112.71	161.39	9.21	8.01	30.13	12.02	10.26	48.40	0.142841	0.53
38	606	14.43	17	346.71	259.29	0	(5.76)	106.80	152.49	8.71	7.56	28.91	11.53	10.00	46.47	0.135522	0.44
39	589	14.02	17	344.14	244.86	0	(5.59)	101.04	143.82	8.21	7.13	27.69	11.05	9.72	44.54	0.128579	0.32
40	572	13.62	17	341.17	230.83	0	(5.43)	95.45	135.38	7.73	6.72	26.48	10.56	9.44	42.64	0.121991	0.21
41	555	13.21	17	337.79	217.21	0	(5.27)	90.02	127.19	7.26	6.31	25.30	10.09	9.16	40.76	0.115740	0.10
42	538	12.81	18	334.00	204.00	0	(5.11)	84.75	119.25	6.81	5.92	24.14	9.63	8.88	38.94	0.109810	0.00
43	520	12.38	18	328.81	191.19	0	(4.94)	79.64	111.55	6.37	5.53	22.98	9.17	8.58	37.09	0.104184	(0.10)
44	502	11.95	18	323.19	178.81	0	(4.77)	74.70	104.11	5.94	5.16	21.83	8.71	8.28	35.27	0.098846	(0.20)
45	484	11.52	18	317.14	166.86	0	(4.60)	69.93	96.93	5.53	4.81	20.72	8.27	7.99	33.52	0.093782	(0.29)
46	466	11.10	18	310.67	155.33	0	(4.43)	65.33	90.00	5.14	4.46	19.64	7.84	7.69	31.80	0.088976	(0.38)
47	448	10.67	19	303.76	144.24	0	(4.26)	60.90	83.34	4.76	4.13	18.58	7.41	7.39	30.10	0.084418	(0.48)
48	429	10.21	18	295.43	133.57	0	(4.07)	56.64	76.93	4.39	3.82	17.53	6.99	7.08	28.42	0.080092	(0.53)
49	411	9.79	19	287.64	123.36	0	(3.90)	52.57	70.79	4.04	3.51	16.51	6.59	6.78	26.81	0.075989	(0.64)
50	392	9.33	19	278.43	113.57	0	(3.72)	48.67	64.90	3.71	3.22	15.51	6.19	6.47	25.20	0.072095	(0.72)
51	373	8.88	18	268.76	104.24	0	(3.54)	44.95	59.29	3.39	2.94	14.53	5.80	6.15	23.62	0.068402	(0.75)
52	355	8.45	19	259.64	95.36	0	(3.37)	41.41	53.95	3.08	2.68	13.58	5.42	5.86	22.12	0.064897	(0.85)
53	336	8.00	18	249.10	86.90	0	(3.19)	38.04	48.86	2.79	2.42	12.64	5.04	5.54	20.60	0.061572	(0.87)
54	318	7.57	19	239.10	78.90	0	(3.02)	34.85	44.05	2.52	2.19	11.76	4.69	5.25	19.20	0.058417	(0.98)
55	299	7.12	18	227.67	71.33	0	(2.84)	31.83	39.50	2.26	1.96	10.88	4.34	4.93	17.77	0.055424	(0.98)
56	281	6.69	18	216.79	64.21	0	(2.67)	28.99	35.22	2.01	1.75	10.03	4.00	4.64	16.42	0.052584	(1.03)
57	263	6.26	17	205.48	57.52	0	(2.50)	26.32	31.20	1.78	1.55	9.22	3.68	4.34	15.11	0.049890	(1.02)
58	246	5.86	18	194.74	51.26	0	(2.34)	23.82	27.44	1.57	1.36	8.46	3.38	4.06	13.89	0.047334	(1.12)
59	228	5.43	17	182.60	45.40	0	(2.17)	21.48	23.92	1.37	1.19	7.70	3.07	3.76	12.65	0.044909	(1.10)
60	211	5.02	16	171.02	39.98	0	(2.00)	19.31	20.67	1.18	1.03	6.99	2.79	3.48	11.50	0.042608	(1.08)
61	195	4.64	16	160.05	34.95	0	(1.85)	17.31	17.64	1.01	0.88	6.33	2.53	3.22	10.43	0.040425	(1.11)
62	179	4.26	16	148.69	30.31	0	(1.70)	15.46	14.85	0.85	0.74	5.68	2.27	2.95	9.37	0.038353	(1.14)
63	163	3.88	15	136.95	26.05	0	(1.55)	13.76	12.29	0.70	0.61	5.04	2.01	2.69	8.34	0.036388	(1.10)
64	148	3.52	14	125.83	22.17	0	(1.41)	12.21	9.96	0.57	0.49	4.47	1.78	2.44	7.39	0.034524	(1.05)
65	134	3.19	14	115.36	18.64	0	(1.27)	10.80	7.84	0.45	0.39	3.94	1.57	2.21	6.54	0.032755	(1.08)
66	120	2.86	13	104.55	15.45	0	(1.14)	9.53	5.92	0.34	0.29	3.42	1.36	1.98	5.69	0.031077	(1.02)
67	107	2.55	13	94.40	12.60	0	(1.02)	8.39	4.21	0.24	0.21	2.94	1.17	1.77	4.92	0.029484	(1.04)
68	94	2.24	11	83.95	10.05	0	(0.89)	7.37	2.68	0.15	0.13	2.49	0.99	1.55	4.17	0.027974	(0.90)
69	83	1.98	11	75.19	7.81	0	(0.79)	6.48	1.33	0.08	0.07	2.11	0.84	1.37	3.55	0.026540	(0.92)
70	72	1.71	10	66.17	5.83	0	(0.68)	5.69	0.14	0.01	0.01	1.74	0.69	1.19	2.93	0.025181	(0.85)
71	62	1.48	10	57.88	4.12	0	(0.59)	5.01	(0.89)	(0.05)	(0.04)	1.39	0.55	1.02	2.37	0.023890	(0.86)
72	52	1.24	8	49.36	2.64	0	(0.49)	4.42	(1.78)	(0.10)	(0.09)	1.08	0.43	0.86	1.85	0.022666	(0.70)
73	44	1.05	8	42.60	1.40	0	(0.42)	3.93	(2.53)	(0.14)	(0.13)	0.81	0.32	0.73	1.41	0.021505	(0.71)
74	36	0.86	7	35.64	0.36	0	(0.34)	3.51	(3.15)	(0.18)	(0.16)	0.56	0.22	0.59	0.99	0.020403	(0.63)
75	29	0.69	6	29.50	(0.50)	0	(0.28)	3.17	(3.67)	(0.21)	(0.18)	0.33	0.13	0.48	0.63	0.019358	(0.54)
76	23	0.55	5	24.19	(1.19)	0	(0.22)	2.89	(4.08)	(0.23)	(0.20)	0.16	0.06	0.38	0.34	0.018366	(0.46)
77	18	0.43	4	19.74	(1.74)	0	(0.17)	2.67	(4.41)	(0.25)	(0.22)	0.01	0.00	0.30	0.09	0.017425	(0.37)
78	14	0.33	4	16.17	(2.17)	0	(0.13)	2.50	(4.67)	(0.27)	(0.23)	(0.11)	(0.04)	0.23	(0.11)	0.016532	(0.37)

79	10	0.24	3	12.50	(2.50)	0	(0.09)	2.37	(4.87)	(0.28)	(0.24)	(0.22)	(0.09)	0.17	(0.29)	0.015685	(0.28)
80	7	0.17	3	9.74	(2.74)	0	(0.07)	2.28	(5.02)	(0.29)	(0.25)	(0.32)	(0.13)	0.12	(0.45)	0.014881	(0.28)
81	4	0.10	2	6.90	(2.90)	0	(0.04)	2.21	(5.11)	(0.29)	(0.25)	(0.39)	(0.16)	0.07	(0.57)	0.014119	(0.19)
82	2	0.05	1	5.00	(3.00)	0	(0.02)	2.17	(5.17)	(0.30)	(0.26)	(0.45)	(0.18)	0.03	(0.68)	0.013395	(0.10)
83	1	0.02	1	4.05	(3.05)	0	(0.01)	2.15	(5.20)	(0.30)	(0.26)	(0.48)	(0.19)	0.02	(0.72)	0.012709	(0.10)
84	0	0.00	0	3.07	(3.07)	0	0.00	2.14	(5.21)	(0.30)	(0.26)	(0.50)	(0.20)	0.00	(0.76)	0.012058	0.00
														P.V. OF REV. RQMT	1,300.70	SUM OF	73.57

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,300.70
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	95.70
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,396.40
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	88.95
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	8.89%

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	TRANSMISSION (OTHER 115 KV POLES)
BOOK LIFE	38
IOWA CURVE	4
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIREME
1	1,000	26.32	0	0.00	1,000.00	37.70	4.54	0	1,000.00	57.10	49.61	83.61	33.36	16.50	187.43	0.948764	0.00
2	1,000	26.32	0	26.32	973.68	72.58	18.46	4.54	969.14	55.33	48.08	45.80	18.27	16.50	182.96	0.900153	0.00
3	1,000	26.32	0	52.63	947.37	67.13	16.28	23.00	924.37	52.78	45.86	46.99	18.75	16.50	176.49	0.854032	0.00
4	1,000	26.32	0	78.95	921.05	62.1	14.28	39.28	881.77	50.34	43.74	47.97	19.14	16.50	170.32	0.810275	0.00
5	1,000	26.32	0	105.26	894.74	57.44	12.42	53.56	841.18	48.03	41.73	48.79	19.46	16.50	164.46	0.768760	0.00
6	1,000	26.32	0	131.58	868.42	53.13	10.70	65.98	802.44	45.82	39.81	49.42	19.72	16.50	158.87	0.729372	0.00
7	1,000	26.32	1	157.89	842.11	49.15	9.11	76.68	765.43	43.70	37.97	49.87	19.90	16.50	153.50	0.692002	0.56
8	999	26.29	0	183.21	815.79	45.46	7.65	85.79	730.00	41.68	36.21	50.18	20.02	16.48	148.33	0.656546	0.00
9	999	26.29	0	209.50	789.50	44.86	7.41	93.44	696.06	39.74	34.53	47.55	18.97	16.48	143.42	0.622907	0.00
10	999	26.29	1	235.79	763.21	44.86	7.41	100.85	662.36	37.82	32.86	44.35	17.69	16.48	138.55	0.590992	0.46
11	998	26.26	1	261.08	736.92	44.86	7.42	108.26	628.66	35.89	31.19	41.12	16.40	16.47	133.63	0.560712	0.43
12	997	26.24	1	286.34	710.66	44.86	7.43	115.68	594.98	33.97	29.52	37.89	15.12	16.45	128.73	0.531983	0.40
13	996	26.21	1	311.58	684.42	44.86	7.44	123.11	561.31	32.05	27.85	34.67	13.83	16.43	123.81	0.504727	0.37
14	995	26.18	1	336.79	658.21	44.86	7.45	130.55	527.66	30.13	26.18	31.45	12.55	16.42	118.91	0.478867	0.34
15	994	26.16	2	361.97	632.03	44.86	7.46	138.00	494.03	28.21	24.51	28.23	11.26	16.40	114.00	0.454331	0.64
16	992	26.11	3	386.13	605.87	44.86	7.48	145.46	460.41	26.29	22.84	24.98	9.97	16.37	109.06	0.431053	0.89
17	989	26.03	3	409.24	579.76	44.86	7.51	152.94	426.82	24.37	21.17	21.71	8.66	16.32	104.06	0.408968	0.82
18	986	25.95	3	432.26	553.74	44.86	7.54	160.45	393.29	22.45	19.51	18.43	7.35	16.27	99.07	0.388014	0.76
19	983	25.87	5	455.21	527.79	44.86	7.58	167.99	359.80	20.54	17.85	15.19	6.06	16.22	94.12	0.368134	1.16
20	978	25.74	5	476.08	501.92	44.86	7.63	175.57	326.35	18.63	16.19	11.87	4.74	16.14	89.07	0.349272	1.07
21	973	25.61	7	496.82	476.18	22.43	(1.27)	183.20	292.98	16.73	14.53	31.00	12.37	16.05	84.02	0.331377	1.37
22	966	25.42	7	515.42	450.58	0	(10.14)	181.93	268.65	15.34	13.33	50.94	20.32	15.94	80.21	0.314398	1.25

23	959	25.24	9	533.84	425.16	0	(10.07)	171.79	253.37	14.47	12.57	49.31	19.67	15.82	77.70	0.298290	1.46
24	950	25.00	11	550.08	399.92	0	(9.97)	161.72	238.20	13.60	11.82	47.63	19.00	15.68	75.13	0.283006	1.62
25	939	24.71	12	564.08	374.92	0	(9.86)	151.75	223.17	12.74	11.07	45.90	18.31	15.49	72.46	0.268506	1.60
26	927	24.39	15	576.79	350.21	0	(9.73)	141.89	208.32	11.89	10.33	44.18	17.63	15.30	69.81	0.254749	1.79
27	912	24.00	16	586.18	325.82	0	(9.57)	132.16	193.66	11.06	9.61	42.41	16.92	15.05	67.07	0.241697	1.70
28	896	23.58	18	594.18	301.82	0	(9.41)	122.59	179.23	10.23	8.89	40.59	16.19	14.78	64.26	0.229313	1.69
29	878	23.11	21	599.76	278.24	0	(9.22)	113.18	165.06	9.42	8.19	38.77	15.47	14.49	61.46	0.217564	1.72
30	857	22.55	23	601.87	255.13	0	(9.00)	103.96	151.17	8.63	7.50	36.91	14.72	14.14	58.54	0.206417	1.63
31	834	21.95	26	601.42	232.58	0	(8.76)	94.96	137.62	7.86	6.83	35.02	13.97	13.76	55.61	0.195841	1.57
32	808	21.26	28	597.37	210.63	0	(8.48)	86.20	124.43	7.10	6.17	33.08	13.20	13.33	52.58	0.185807	1.41
33	780	20.53	32	590.63	189.37	0	(8.19)	77.72	111.65	6.37	5.54	31.12	12.41	12.87	49.53	0.176287	1.30
34	748	19.68	35	579.16	168.84	0	(7.85)	69.53	99.31	5.67	4.93	29.12	11.62	12.34	46.39	0.167255	1.11
35	713	18.76	39	563.84	149.16	0	(7.49)	61.68	87.48	4.99	4.34	27.06	10.80	11.76	43.16	0.158685	0.90
36	674	17.74	45	543.61	130.39	0	(7.08)	54.19	76.20	4.35	3.78	24.97	9.96	11.12	39.87	0.150555	0.68
37	629	16.55	49	516.34	112.66	0	(6.60)	47.11	65.55	3.74	3.25	22.78	9.09	10.38	36.41	0.142841	0.36
38	580	15.26	53	483.89	96.11	0	(6.09)	40.51	55.60	3.17	2.76	20.54	8.19	9.57	32.86	0.135522	0.00
39	527	13.87	56	446.16	80.84	0	(5.53)	34.42	46.42	2.65	2.30	18.28	7.29	8.70	29.28	0.128579	(0.39)
40	471	12.39	57	404.03	66.97	0	(4.94)	28.89	38.08	2.17	1.89	16.01	6.39	7.77	25.67	0.121991	(0.77)
41	414	10.89	57	359.42	54.58	0	(4.35)	23.95	30.63	1.75	1.52	13.80	5.51	6.83	22.15	0.115740	(1.13)
42	357	9.39	55	313.32	43.68	0	(3.75)	19.60	24.08	1.38	1.19	11.69	4.66	5.89	18.76	0.109810	(1.41)
43	302	7.95	52	267.71	34.29	0	(3.17)	15.85	18.44	1.05	0.91	9.70	3.87	4.98	15.59	0.104184	(1.63)
44	250	6.58	47	223.66	26.34	0	(2.62)	12.68	13.66	0.78	0.68	7.88	3.14	4.13	12.69	0.098846	(1.72)
45	203	5.34	42	183.24	19.76	0	(2.13)	10.06	9.70	0.55	0.48	6.26	2.50	3.35	10.09	0.093782	(1.75)
46	161	4.24	37	146.58	14.42	0	(1.69)	7.93	6.49	0.37	0.32	4.85	1.93	2.66	7.83	0.088976	(1.72)
47	124	3.26	31	113.82	10.18	0	(1.30)	6.24	3.94	0.23	0.20	3.65	1.46	2.05	5.90	0.084418	(1.58)
48	93	2.45	26	86.08	6.92	0	(0.98)	4.94	1.98	0.11	0.10	2.62	1.05	1.53	4.26	0.080092	(1.44)
49	67	1.76	21	62.53	4.47	0	(0.70)	3.96	0.51	0.03	0.03	1.82	0.73	1.11	2.96	0.075989	(1.25)
50	46	1.21	16	43.29	2.71	0	(0.48)	3.26	(0.55)	(0.03)	(0.03)	1.17	0.47	0.76	1.90	0.072095	(1.01)
51	30	0.79	12	28.50	1.50	0	(0.31)	2.78	(1.28)	(0.07)	(0.06)	0.68	0.27	0.50	1.12	0.068402	(0.81)
52	18	0.47	8	17.29	0.71	0	(0.19)	2.47	(1.76)	(0.10)	(0.09)	0.31	0.12	0.30	0.51	0.064897	(0.57)
53	10	0.26	5	9.76	0.24	0	(0.10)	2.28	(2.04)	(0.12)	(0.10)	0.07	0.03	0.17	0.14	0.061572	(0.37)
54	5	0.13	3	5.03	(0.03)	0	(0.05)	2.18	(2.21)	(0.13)	(0.11)	(0.08)	(0.03)	0.08	(0.11)	0.058417	(0.23)
55	2	0.05	1	2.16	(0.16)	0	(0.02)	2.13	(2.29)	(0.13)	(0.11)	(0.16)	(0.06)	0.03	(0.24)	0.055424	(0.08)
56	1	0.03	1	1.21	(0.21)	0	(0.01)	2.11	(2.32)	(0.13)	(0.12)	(0.19)	(0.08)	0.02	(0.29)	0.052584	(0.08)
57	0	0.00	0	0.24	(0.24)	0	0.00	2.10	(2.34)	(0.13)	(0.12)	(0.22)	(0.09)	0.00	(0.34)	0.049890	0.00
58	0	0.00	0	0.24	(0.24)	0	0.00	2.10	(2.34)	(0.13)	(0.12)	(0.22)	(0.09)	0.00	(0.34)	0.047334	0.00
59	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.044909	0.00
60	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.042608	0.00
61	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.040425	0.00
62	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.038353	0.00
63	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.036388	0.00
64	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.034524	0.00
65	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.032755	0.00
66	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.031077	0.00
67	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.029484	0.00
68	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.027974	0.00
69	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.026540	0.00
70	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.025181	0.00
71	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.023890	0.00
72	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.022666	0.00
73	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.021505	0.00
74	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.020403	0.00
75	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.019358	0.00
76	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.018366	0.00
77	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00
													P.V. OF REV. RQMT		1,318.93	SUM OF	13.09

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,318.93
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	17.26
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,336.20
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	87.64
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	8.76%

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	TRANSMISSION (OVERHEAD CONDUCTORS - OTHER TRAN)
BOOK LIFE	38
IOWA CURVE	2.5
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	999	26.29	1	0.00	999.00	37.70	4.55	0	999.00	57.04	49.56	83.48	33.30	16.48	187.22	0.948764	0.81
2	998	26.26	2	25.29	972.71	72.58	18.48	4.55	968.16	55.28	48.03	45.66	18.22	16.47	182.74	0.900153	1.53
3	996	26.21	2	49.55	946.45	67.13	16.32	23.03	923.42	52.72	45.81	46.78	18.66	16.43	176.15	0.854032	1.44
4	994	26.16	2	73.76	920.24	62.1	14.34	39.35	880.89	50.29	43.70	47.73	19.04	16.40	169.93	0.810275	1.35
5	992	26.11	3	97.92	894.08	57.44	12.50	53.69	840.39	47.98	41.69	48.49	19.34	16.37	163.99	0.768760	1.90
6	989	26.03	2	121.03	867.97	53.13	10.81	66.19	801.78	45.78	39.77	49.06	19.57	16.32	158.28	0.729372	1.19
7	987	25.97	3	145.05	841.95	49.15	9.25	77.00	764.95	43.67	37.95	49.49	19.74	16.29	152.87	0.692002	1.67
8	984	25.89	4	168.03	815.97	45.46	7.81	86.25	729.72	41.66	36.20	49.75	19.85	16.24	147.65	0.656546	2.08
9	980	25.79	3	189.92	790.08	44.86	7.61	94.06	696.02	39.74	34.53	47.05	18.77	16.17	142.61	0.622907	1.46
10	977	25.71	4	212.71	764.29	44.86	7.64	101.67	662.62	37.83	32.87	43.79	17.47	16.12	137.64	0.590992	1.82
11	973	25.61	5	234.42	738.58	44.86	7.68	109.31	629.27	35.93	31.22	40.52	16.16	16.05	132.65	0.560712	2.13
12	968	25.47	5	255.03	712.97	44.86	7.73	116.99	595.98	34.03	29.57	37.22	14.85	15.97	127.62	0.531983	1.98
13	963	25.34	5	275.50	687.50	44.86	7.79	124.72	562.78	32.13	27.92	33.94	13.54	15.89	122.61	0.504727	1.85
14	958	25.21	6	295.84	662.16	44.86	7.84	132.51	529.65	30.24	26.27	30.66	12.23	15.81	117.60	0.478867	2.06
15	952	25.05	6	315.05	636.95	44.86	7.90	140.35	496.60	28.35	24.64	27.36	10.91	15.71	112.56	0.454331	1.91
16	946	24.89	7	334.11	611.89	44.86	7.96	148.25	463.64	26.47	23.00	24.07	9.60	15.61	107.53	0.431053	2.07
17	939	24.71	8	352.00	587.00	44.86	8.04	156.21	430.79	24.60	21.37	20.78	8.29	15.49	102.50	0.408968	2.19
18	931	24.50	9	368.71	562.29	44.86	8.12	164.25	398.04	22.73	19.75	17.45	6.96	15.36	97.42	0.388014	2.27
19	922	24.26	9	384.21	537.79	44.86	8.22	172.37	365.42	20.86	18.13	14.11	5.63	15.21	92.31	0.368134	2.09
20	913	24.03	10	399.47	513.53	44.86	8.31	180.59	332.94	19.01	16.52	10.79	4.30	15.06	87.23	0.349272	2.14
21	903	23.76	10	413.50	489.50	22.43	(0.53)	188.90	300.60	17.16	14.91	29.89	11.92	14.90	82.12	0.331377	1.96
22	893	23.50	12	427.26	465.74	0	(9.38)	188.37	277.37	15.84	13.76	49.85	19.89	14.73	78.34	0.314398	2.15

23	881	23.18	13	438.76	442.24	0	(9.25)	178.99	263.25	15.03	13.06	48.19	19.22	14.54	75.78	0.298290	2.12
24	868	22.84	13	448.95	419.05	0	(9.11)	169.74	249.31	14.23	12.37	46.52	18.56	14.32	73.21	0.283006	1.92
25	855	22.50	15	458.79	396.21	0	(8.98)	160.63	235.58	13.45	11.69	44.87	17.90	14.11	70.67	0.268506	1.99
26	840	22.11	16	466.29	373.71	0	(8.82)	151.65	222.06	12.68	11.02	43.20	17.23	13.86	68.08	0.254749	1.91
27	824	21.68	17	472.39	351.61	0	(8.65)	142.83	208.78	11.92	10.36	41.52	16.56	13.60	65.47	0.241697	1.80
28	807	21.24	18	477.08	329.92	0	(8.47)	134.18	195.74	11.18	9.71	39.84	15.89	13.32	62.87	0.229313	1.69
29	789	20.76	20	480.32	308.68	0	(8.28)	125.71	182.97	10.45	9.08	38.15	15.22	13.02	60.25	0.217564	1.64
30	769	20.24	21	481.08	287.92	0	(8.07)	117.43	170.49	9.73	8.46	36.43	14.53	12.69	57.58	0.206417	1.49
31	748	19.68	22	480.32	267.68	0	(7.85)	109.36	158.32	9.04	7.85	34.73	13.86	12.34	54.92	0.195841	1.33
32	726	19.11	24	478.00	248.00	0	(7.62)	101.51	146.49	8.36	7.27	33.02	13.17	11.98	52.27	0.185807	1.21
33	702	18.47	26	473.11	228.89	0	(7.37)	93.89	135.00	7.71	6.70	31.30	12.49	11.58	49.58	0.176287	1.06
34	676	17.79	26	465.58	210.42	0	(7.10)	86.52	123.90	7.07	6.15	29.55	11.79	11.15	46.85	0.167255	0.83
35	650	17.11	29	457.37	192.63	0	(6.82)	79.42	113.21	6.46	5.62	27.86	11.11	10.73	44.21	0.158685	0.67
36	621	16.34	30	445.47	175.53	0	(6.52)	72.60	102.93	5.88	5.11	26.12	10.42	10.25	41.48	0.150555	0.45
37	591	15.55	31	431.82	159.18	0	(6.20)	66.08	93.10	5.32	4.62	24.41	9.74	9.75	38.78	0.142841	0.23
38	560	14.74	32	416.37	143.63	0	(5.88)	59.88	83.75	4.78	4.15	22.69	9.05	9.24	36.08	0.135522	0.00
39	528	13.89	34	399.11	128.89	0	(5.54)	54.00	74.89	4.28	3.72	21.02	8.39	8.71	33.45	0.128579	(0.24)
40	494	13.00	34	379.00	115.00	0	(5.19)	48.46	66.54	3.80	3.30	19.32	7.71	8.15	30.77	0.121991	(0.46)
41	460	12.11	34	358.00	102.00	0	(4.83)	43.27	58.73	3.35	2.91	17.68	7.05	7.59	28.18	0.115740	(0.67)
42	426	11.21	35	336.11	89.89	0	(4.47)	38.44	51.45	2.94	2.55	16.11	6.43	7.03	25.69	0.109810	(0.90)
43	391	10.29	35	312.32	78.68	0	(4.10)	33.97	44.71	2.55	2.22	14.54	5.80	6.45	23.21	0.104184	(1.10)
44	356	9.37	33	287.61	68.39	0	(3.74)	29.87	38.52	2.20	1.91	13.02	5.19	5.87	20.80	0.098846	(1.21)
45	323	8.50	33	263.97	59.03	0	(3.39)	26.13	32.90	1.88	1.63	11.63	4.64	5.33	18.59	0.093782	(1.38)
46	290	7.63	32	239.47	50.53	0	(3.04)	22.74	27.79	1.59	1.38	10.28	4.10	4.79	16.45	0.088976	(1.49)
47	258	6.79	30	215.11	42.89	0	(2.71)	19.70	23.19	1.32	1.15	8.98	3.58	4.26	14.39	0.084418	(1.53)
48	228	6.00	28	191.89	36.11	0	(2.39)	16.99	19.12	1.09	0.95	7.82	3.12	3.76	12.53	0.080092	(1.55)
49	200	5.26	26	169.89	30.11	0	(2.10)	14.60	15.51	0.89	0.77	6.74	2.69	3.30	10.81	0.075989	(1.55)
50	174	4.58	24	149.16	24.84	0	(1.83)	12.50	12.34	0.70	0.61	5.74	2.29	2.87	9.22	0.072095	(1.52)
51	150	3.95	22	129.74	20.26	0	(1.57)	10.67	9.59	0.55	0.48	4.87	1.94	2.48	7.83	0.068402	(1.48)
52	128	3.37	20	111.68	16.32	0	(1.34)	9.10	7.22	0.41	0.36	4.06	1.62	2.11	6.53	0.064897	(1.41)
53	108	2.84	18	95.05	12.95	0	(1.13)	7.76	5.19	0.30	0.26	3.35	1.34	1.78	5.39	0.061572	(1.33)
54	90	2.37	15	79.89	10.11	0	(0.94)	6.63	3.48	0.20	0.17	2.71	1.08	1.49	4.37	0.058417	(1.16)
55	75	1.97	14	67.26	7.74	0	(0.79)	5.69	2.05	0.12	0.10	2.17	0.87	1.24	3.51	0.055424	(1.12)
56	61	1.61	12	55.24	5.76	0	(0.64)	4.90	0.86	0.05	0.04	1.69	0.67	1.01	2.74	0.052584	(1.00)
57	49	1.29	10	44.84	4.16	0	(0.51)	4.26	(0.10)	(0.01)	(0.01)	1.28	0.51	0.81	2.08	0.049890	(0.86)
58	39	1.03	8	36.13	2.87	0	(0.41)	3.75	(0.88)	(0.05)	(0.04)	0.94	0.38	0.64	1.55	0.047334	(0.71)
59	31	0.82	7	29.16	1.84	0	(0.33)	3.34	(1.50)	(0.09)	(0.07)	0.66	0.26	0.51	1.10	0.044909	(0.63)
60	24	0.63	6	22.97	1.03	0	(0.25)	3.01	(1.98)	(0.11)	(0.10)	0.45	0.18	0.40	0.75	0.042608	(0.56)
61	18	0.47	5	17.61	0.39	0	(0.19)	2.76	(2.37)	(0.14)	(0.12)	0.24	0.10	0.30	0.42	0.040425	(0.48)
62	13	0.34	4	13.08	(0.08)	0	(0.14)	2.57	(2.65)	(0.15)	(0.13)	0.09	0.04	0.21	0.17	0.038353	(0.39)
63	9	0.24	2	9.42	(0.42)	0	(0.09)	2.43	(2.85)	(0.16)	(0.14)	(0.02)	(0.01)	0.15	(0.01)	0.036388	(0.20)
64	7	0.18	3	7.66	(0.66)	0	(0.07)	2.34	(3.00)	(0.17)	(0.15)	(0.09)	(0.04)	0.12	(0.13)	0.034524	(0.30)
65	4	0.11	1	4.84	(0.84)	0	(0.04)	2.27	(3.11)	(0.18)	(0.15)	(0.19)	(0.08)	0.07	(0.27)	0.032755	(0.10)
66	3	0.08	2	3.95	(0.95)	0	(0.03)	2.23	(3.18)	(0.18)	(0.16)	(0.22)	(0.09)	0.05	(0.33)	0.031077	(0.21)
67	1	0.03	0	2.03	(1.03)	0	(0.01)	2.20	(3.23)	(0.18)	(0.16)	(0.27)	(0.11)	0.02	(0.41)	0.029484	0.00
68	1	0.03	1	2.05	(1.05)	0	(0.01)	2.19	(3.24)	(0.19)	(0.16)	(0.29)	(0.12)	0.02	(0.43)	0.027974	(0.11)
69	0	0.00	0	1.08	(1.08)	0	0.00	2.18	(3.26)	(0.19)	(0.16)	(0.32)	(0.13)	0.00	(0.48)	0.026540	0.00
70	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.025181	0.00
71	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.023890	0.00
72	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.022666	0.00
73	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.021505	0.00
74	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.020403	0.00
75	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.019358	0.00
76	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.018366	0.00
77	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00

P.V. OF REV. RQMT 1,313.19 SUM OF 34.74

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,313.19
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	45.62
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,358.81
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	89.13
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	8.91%

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	DISTRIBUTION POLES
BOOK LIFE	33
IOWA CURVE	0
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	1,000	30.30	3	0.00	1,000.00	38.46	3.25	0	1,000.00	57.10	49.61	86.83	34.64	16.50	191.40	0.948764	2.32
2	997	30.21	4	27.30	969.70	74.04	17.48	3.25	966.45	55.18	47.94	47.97	19.14	16.45	186.40	0.900153	2.90
3	993	30.09	6	53.52	939.48	68.48	15.31	20.73	918.75	52.46	45.58	48.88	19.50	16.38	179.32	0.854032	4.07
4	987	29.91	7	77.61	909.39	63.35	13.34	36.04	873.35	49.86	43.33	49.51	19.75	16.29	172.48	0.810275	4.44
5	980	29.70	8	100.52	879.48	58.6	11.53	49.38	830.10	47.39	41.18	49.94	19.92	16.17	165.89	0.768760	4.74
6	972	29.45	9	122.21	849.79	54.2	9.87	60.91	788.88	45.04	39.13	50.19	20.02	16.04	159.55	0.729372	4.98
7	963	29.18	10	142.67	820.33	50.14	8.36	70.78	749.55	42.80	37.18	50.25	20.05	15.89	153.46	0.692002	5.16
8	953	28.88	11	161.85	791.15	46.38	6.98	79.14	712.01	40.65	35.32	50.13	20.00	15.72	147.55	0.656546	5.28
9	942	28.55	12	179.73	762.27	45.76	6.87	86.12	676.15	38.60	33.54	47.01	18.75	15.54	141.85	0.622907	5.36
10	930	28.18	13	196.27	733.73	45.76	7.01	92.99	640.74	36.58	31.79	43.28	17.27	15.35	136.18	0.590992	5.39
11	917	27.79	14	211.45	705.55	45.76	7.17	100.00	605.55	34.57	30.04	39.54	15.77	15.13	130.47	0.560712	5.38
12	903	27.36	14	225.24	677.76	45.76	7.34	107.17	570.59	32.58	28.31	35.81	14.29	14.90	124.78	0.531983	4.98
13	889	26.94	15	238.61	650.39	45.76	7.51	114.51	535.88	30.60	26.58	32.09	12.80	14.67	119.10	0.504727	4.93
14	874	26.48	16	250.55	623.45	45.76	7.69	122.02	501.43	28.63	24.88	28.36	11.31	14.42	113.41	0.478867	4.84
15	858	26.00	16	261.03	596.97	45.76	7.88	129.71	467.26	26.68	23.18	24.62	9.82	14.16	107.72	0.454331	4.45
16	842	25.52	16	271.03	570.97	45.76	8.08	137.59	433.38	24.74	21.50	20.92	8.35	13.89	102.08	0.431053	4.08
17	826	25.03	18	280.55	545.45	45.76	8.27	145.67	399.78	22.83	19.83	17.25	6.88	13.63	96.47	0.408968	4.19
18	808	24.48	17	287.58	520.42	45.76	8.49	153.94	366.48	20.92	18.18	13.53	5.40	13.33	90.80	0.388014	3.60
19	791	23.97	19	295.06	495.94	45.76	8.69	162.43	333.51	19.04	16.54	9.88	3.94	13.05	85.23	0.368134	3.65
20	772	23.39	18	300.03	471.97	45.76	8.92	171.12	300.85	17.18	14.92	6.21	2.48	12.74	79.63	0.349272	3.11
21	754	22.85	19	305.42	448.58	22.88	0.01	180.04	268.54	15.33	13.32	25.47	10.16	12.44	74.11	0.331377	2.95
22	735	22.27	19	309.27	425.73	0	(8.89)	180.05	245.68	14.03	12.19	45.61	18.20	12.13	69.93	0.314398	2.62

23	716	21.70	20	312.55	403.45	0	(8.66)	171.16	232.29	13.26	11.52	43.75	17.45	11.81	67.08	0.298290	2.44
24	696	21.09	20	314.24	381.76	0	(8.41)	162.50	219.26	12.52	10.88	41.93	16.73	11.48	64.29	0.283006	2.13
25	676	20.48	20	315.33	360.67	0	(8.17)	154.09	206.58	11.79	10.25	40.10	16.00	11.15	61.50	0.268506	1.84
26	656	19.88	20	315.82	340.18	0	(7.93)	145.92	194.26	11.09	9.64	38.33	15.29	10.82	58.79	0.254749	1.57
27	636	19.27	21	315.70	320.30	0	(7.69)	137.99	182.31	10.41	9.04	36.59	14.60	10.49	56.12	0.241697	1.37
28	615	18.64	21	313.97	301.03	0	(7.43)	130.30	170.73	9.75	8.47	34.87	13.91	10.15	53.49	0.229313	1.11
29	594	18.00	20	311.61	282.39	0	(7.18)	122.87	159.52	9.11	7.91	33.16	13.23	9.80	50.87	0.217564	0.83
30	574	17.39	21	309.61	264.39	0	(6.94)	115.69	148.70	8.49	7.38	31.52	12.57	9.47	48.36	0.206417	0.63
31	553	16.76	21	306.00	247.00	0	(6.69)	108.75	138.25	7.89	6.86	29.88	11.92	9.12	45.86	0.195841	0.41
32	532	16.12	21	301.76	230.24	0	(6.43)	102.06	128.18	7.32	6.36	28.30	11.29	8.78	43.44	0.185807	0.20
33	511	15.48	21	296.88	214.12	0	(6.18)	95.63	118.49	6.77	5.88	26.74	10.67	8.43	41.05	0.176287	0.00
34	490	14.85	22	291.36	198.64	0	(5.92)	89.45	109.19	6.23	5.42	25.22	10.06	8.09	38.73	0.167255	(0.20)
35	468	14.18	21	284.21	183.79	0	(5.66)	83.53	100.26	5.72	4.97	23.69	9.45	7.72	36.38	0.158685	(0.37)
36	447	13.55	20	277.39	169.61	0	(5.40)	77.87	91.74	5.24	4.55	22.27	8.88	7.38	34.20	0.150555	(0.51)
37	427	12.94	21	270.94	156.06	0	(5.16)	72.47	83.59	4.77	4.15	20.88	8.33	7.05	32.08	0.142841	(0.70)
38	406	12.30	21	262.88	143.12	0	(4.91)	67.31	75.81	4.33	3.76	19.50	7.78	6.70	29.96	0.135522	(0.86)
39	385	11.67	21	254.18	130.82	0	(4.65)	62.40	68.42	3.91	3.39	18.18	7.25	6.35	27.92	0.128579	(1.00)
40	364	11.03	20	244.85	119.15	0	(4.40)	57.75	61.40	3.51	3.05	16.87	6.73	6.01	25.93	0.121991	(1.09)
41	344	10.42	20	235.88	108.12	0	(4.16)	53.35	54.77	3.13	2.72	15.63	6.24	5.68	24.03	0.115740	(1.21)
42	324	9.82	20	226.30	97.70	0	(3.92)	49.19	48.51	2.77	2.41	14.42	5.75	5.35	22.18	0.109810	(1.33)
43	304	9.21	20	216.12	87.88	0	(3.68)	45.27	42.61	2.43	2.11	13.25	5.29	5.02	20.38	0.104184	(1.44)
44	284	8.61	19	205.33	78.67	0	(3.43)	41.59	37.08	2.12	1.84	12.14	4.84	4.69	18.67	0.098846	(1.47)
45	265	8.03	19	194.94	70.06	0	(3.20)	38.16	31.90	1.82	1.58	11.06	4.41	4.37	17.01	0.093782	(1.57)
46	246	7.45	18	183.97	62.03	0	(2.97)	34.96	27.07	1.55	1.34	10.04	4.01	4.06	15.44	0.088976	(1.57)
47	228	6.91	18	173.42	54.58	0	(2.76)	31.99	22.59	1.29	1.12	9.05	3.61	3.76	13.93	0.084418	(1.65)
48	210	6.36	18	162.33	47.67	0	(2.54)	29.23	18.44	1.05	0.91	8.11	3.24	3.47	12.49	0.080092	(1.73)
49	192	5.82	17	150.70	41.30	0	(2.32)	26.69	14.61	0.83	0.72	7.20	2.87	3.17	11.09	0.075989	(1.71)
50	175	5.30	17	139.52	35.48	0	(2.12)	24.37	11.11	0.63	0.55	6.34	2.53	2.89	9.78	0.072095	(1.77)
51	158	4.79	16	127.82	30.18	0	(1.91)	22.25	7.93	0.45	0.39	5.54	2.21	2.61	8.54	0.068402	(1.73)
52	142	4.30	16	116.61	25.39	0	(1.72)	20.34	5.05	0.29	0.25	4.78	1.91	2.34	7.37	0.064897	(1.78)
53	126	3.82	15	104.91	21.09	0	(1.52)	18.62	2.47	0.14	0.12	4.06	1.62	2.08	6.26	0.061572	(1.72)
54	111	3.36	14	93.73	17.27	0	(1.34)	17.10	0.17	0.01	0.01	3.38	1.35	1.83	5.22	0.058417	(1.65)
55	97	2.94	14	83.09	13.91	0	(1.17)	15.76	(1.85)	(0.11)	(0.09)	2.76	1.10	1.60	4.27	0.055424	(1.69)
56	83	2.52	13	72.03	10.97	0	(1.00)	14.59	(3.62)	(0.21)	(0.18)	2.17	0.87	1.37	3.37	0.052584	(1.61)
57	70	2.12	11	61.55	8.45	0	(0.85)	13.59	(5.14)	(0.29)	(0.25)	1.63	0.65	1.16	2.54	0.049890	(1.39)
58	59	1.79	12	52.67	6.33	0	(0.71)	12.74	(6.41)	(0.37)	(0.32)	1.18	0.47	0.97	1.83	0.047334	(1.55)
59	47	1.42	10	42.45	4.55	0	(0.57)	12.03	(7.48)	(0.43)	(0.37)	0.71	0.28	0.78	1.11	0.044909	(1.31)
60	37	1.12	9	33.88	3.12	0	(0.45)	11.46	(8.34)	(0.48)	(0.41)	0.32	0.13	0.61	0.52	0.042608	(1.20)
61	28	0.85	8	26.00	2.00	0	(0.34)	11.01	(9.01)	(0.51)	(0.45)	0.00	0.00	0.46	0.01	0.040425	(1.09)
62	20	0.61	7	18.85	1.15	0	(0.24)	10.67	(9.52)	(0.54)	(0.47)	(0.29)	(0.12)	0.33	(0.43)	0.038353	(0.97)
63	13	0.39	6	12.45	0.55	0	(0.16)	10.43	(9.88)	(0.56)	(0.49)	(0.54)	(0.22)	0.21	(0.83)	0.036388	(0.84)
64	7	0.21	4	6.85	0.15	0	(0.08)	10.27	(10.12)	(0.58)	(0.50)	(0.75)	(0.30)	0.12	(1.13)	0.034524	(0.57)
65	3	0.09	3	3.06	(0.06)	0	(0.04)	10.19	(10.25)	(0.59)	(0.51)	(0.90)	(0.36)	0.05	(1.36)	0.032755	(0.43)
66	0	0.00	0	0.15	(0.15)	0	0.00	10.15	(10.30)	(0.59)	(0.51)	(0.98)	(0.39)	0.00	(1.49)	0.031077	0.00
67	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.029484	0.00
68	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.027974	0.00
69	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.026540	0.00
70	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.025181	0.00
71	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.023890	0.00
72	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.022666	0.00
73	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.021505	0.00
74	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.020403	0.00
75	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.019358	0.00
76	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.018366	0.00
77	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00

P.V. OF REV. RQMT 1,306.09 SUM OF 66.23

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,306.09
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	86.51
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,392.60
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	95.86
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	9.59%

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	DISTRIBUTION LINES
BOOK LIFE	38
IOWA CURVE	0.5
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	995	26.18	10	0.00	995.00	38.46	4.90	0	995.00	56.81	49.36	82.24	32.81	16.42	186.48	0.948764	8.13
2	985	25.92	10	16.18	968.82	74.04	19.20	4.90	963.92	55.03	47.82	43.44	17.33	16.25	181.55	0.900153	7.65
3	975	25.66	11	32.11	942.89	68.48	17.08	24.10	918.79	52.46	45.58	44.45	17.73	16.09	174.60	0.854032	7.90
4	964	25.37	10	46.76	917.24	63.35	15.15	41.18	876.06	50.02	43.46	45.23	18.04	15.91	167.95	0.810275	6.75
5	954	25.11	11	62.13	891.87	58.6	13.36	56.33	835.54	47.71	41.45	45.88	18.30	15.74	161.67	0.768760	6.97
6	943	24.82	10	76.24	866.76	54.2	11.72	69.69	797.07	45.51	39.54	46.33	18.48	15.56	155.63	0.729372	5.94
7	933	24.55	11	91.05	841.95	50.14	10.21	81.41	760.54	43.42	37.73	46.66	18.61	15.39	149.91	0.692002	6.12
8	922	24.26	11	104.61	817.39	46.38	8.82	91.62	725.77	41.44	36.00	46.82	18.68	15.21	144.41	0.656546	5.73
9	911	23.97	11	117.87	793.13	45.76	8.69	100.44	692.69	39.55	34.36	44.01	17.56	15.03	139.16	0.622907	5.36
10	900	23.68	11	130.84	769.16	45.76	8.81	109.13	660.03	37.68	32.74	40.62	16.20	14.85	133.96	0.590992	5.01
11	889	23.39	12	143.53	745.47	45.76	8.92	117.94	627.53	35.83	31.13	37.24	14.86	14.67	128.80	0.560712	5.10
12	877	23.08	11	154.92	722.08	45.76	9.05	126.86	595.22	33.98	29.53	33.85	13.50	14.47	123.61	0.531983	4.36
13	866	22.79	12	167.00	699.00	45.76	9.16	135.91	563.09	32.15	27.93	30.51	12.17	14.29	118.49	0.504727	4.43
14	854	22.47	11	177.79	676.21	45.76	9.29	145.07	531.14	30.33	26.35	27.17	10.84	14.09	113.37	0.478867	3.78
15	843	22.18	12	189.26	653.74	45.76	9.41	154.36	499.38	28.51	24.77	23.86	9.52	13.91	108.30	0.454331	3.83
16	831	21.87	12	199.45	631.55	45.76	9.53	163.77	467.78	26.71	23.21	20.54	8.19	13.71	103.22	0.431053	3.55
17	819	21.55	12	209.32	609.68	45.76	9.66	173.30	436.38	24.92	21.65	17.26	6.89	13.51	98.18	0.408968	3.28
18	807	21.24	12	218.87	588.13	45.76	9.78	182.96	405.17	23.13	20.10	13.95	5.57	13.32	93.14	0.388014	3.03
19	795	20.92	13	228.11	566.89	45.76	9.91	192.74	374.15	21.36	18.56	10.70	4.27	13.12	88.14	0.368134	3.02
20	782	20.58	12	236.03	545.97	45.76	10.05	202.65	343.32	19.60	17.03	7.44	2.97	12.90	83.13	0.349272	2.56
21	770	20.26	13	244.61	525.39	22.88	1.04	212.70	312.69	17.85	15.51	27.07	10.80	12.71	78.17	0.331377	2.55
22	757	19.92	13	251.87	505.13	0	(7.95)	213.74	291.39	16.64	14.46	47.60	18.99	12.49	74.55	0.314398	2.33

23	744	19.58	14	258.79	485.21	0	(7.81)	205.79	279.42	15.95	13.86	46.12	18.40	12.28	72.26	0.298290	2.28
24	730	19.21	13	264.37	465.63	0	(7.66)	197.98	267.65	15.28	13.28	44.64	17.81	12.05	69.97	0.283006	1.92
25	717	18.87	14	270.58	446.42	0	(7.53)	190.32	256.10	14.62	12.70	43.19	17.23	11.83	67.72	0.268506	1.86
26	703	18.50	13	275.45	427.55	0	(7.38)	182.79	244.76	13.97	12.14	41.74	16.65	11.60	65.48	0.254749	1.55
27	690	18.16	15	280.95	409.05	0	(7.24)	175.41	233.64	13.34	11.59	40.36	16.10	11.39	63.34	0.241697	1.59
28	675	17.76	14	284.11	390.89	0	(7.09)	168.17	222.72	12.72	11.05	38.92	15.53	11.14	61.11	0.229313	1.31
29	661	17.39	14	287.87	373.13	0	(6.94)	161.08	212.05	12.11	10.52	37.54	14.98	10.91	58.97	0.217564	1.15
30	647	17.03	15	291.26	355.74	0	(6.79)	154.14	201.60	11.51	10.00	36.18	14.43	10.68	56.86	0.206417	1.06
31	632	16.63	15	293.29	338.71	0	(6.63)	147.35	191.36	10.93	9.49	34.82	13.89	10.43	54.74	0.195841	0.90
32	617	16.24	15	294.92	322.08	0	(6.48)	140.72	181.36	10.35	9.00	33.45	13.34	10.18	52.63	0.185807	0.75
33	602	15.84	16	296.16	305.84	0	(6.32)	134.24	171.60	9.80	8.51	32.15	12.83	9.93	50.59	0.176287	0.65
34	586	15.42	15	296.00	290.00	0	(6.15)	127.92	162.08	9.25	8.04	30.81	12.29	9.67	48.52	0.167255	0.48
35	571	15.03	16	296.42	274.58	0	(5.99)	121.77	152.81	8.72	7.58	29.54	11.78	9.42	46.54	0.158685	0.37
36	555	14.61	16	295.45	259.55	0	(5.83)	115.78	143.77	8.21	7.13	28.26	11.27	9.16	44.55	0.150555	0.24
37	539	14.18	16	294.05	244.95	0	(5.66)	109.95	135.00	7.71	6.70	27.01	10.78	8.89	42.60	0.142841	0.12
38	523	13.76	17	292.24	230.76	0	(5.49)	104.29	126.47	7.22	6.27	25.78	10.28	8.63	40.67	0.135522	0.00
39	506	13.32	16	289.00	217.00	0	(5.31)	98.80	118.20	6.75	5.86	24.55	9.79	8.35	38.76	0.128579	(0.11)
40	490	12.89	17	286.32	203.68	0	(5.14)	93.49	110.19	6.29	5.47	23.37	9.32	8.09	36.92	0.121991	(0.23)
41	473	12.45	16	282.21	190.79	0	(4.97)	88.35	102.44	5.85	5.08	22.17	8.84	7.80	35.05	0.115740	(0.32)
42	457	12.03	17	278.66	178.34	0	(4.80)	83.38	94.96	5.42	4.71	21.04	8.39	7.54	33.29	0.109810	(0.44)
43	440	11.58	17	273.68	166.32	0	(4.62)	78.58	87.74	5.01	4.35	19.91	7.94	7.26	31.52	0.104184	(0.53)
44	423	11.13	17	268.26	154.74	0	(4.44)	73.96	80.78	4.61	4.01	18.80	7.50	6.98	29.79	0.098846	(0.62)
45	406	10.68	17	262.39	143.61	0	(4.26)	69.52	74.09	4.23	3.68	17.73	7.07	6.70	28.10	0.093782	(0.71)
46	389	10.24	17	256.08	132.92	0	(4.08)	65.26	67.66	3.86	3.36	16.67	6.65	6.42	26.45	0.088976	(0.79)
47	372	9.79	16	249.32	122.68	0	(3.91)	61.18	61.50	3.51	3.05	15.62	6.23	6.14	24.81	0.084418	(0.82)
48	356	9.37	17	243.11	112.89	0	(3.74)	57.27	55.62	3.18	2.76	14.65	5.84	5.87	23.28	0.080092	(0.94)
49	339	8.92	17	235.47	103.53	0	(3.56)	53.53	50.00	2.85	2.48	13.66	5.45	5.59	21.73	0.075989	(1.01)
50	322	8.47	17	227.39	94.61	0	(3.38)	49.97	44.64	2.55	2.21	12.72	5.07	5.31	20.23	0.072095	(1.08)
51	305	8.03	16	218.87	86.13	0	(3.20)	46.59	39.54	2.26	1.96	11.79	4.70	5.03	18.78	0.068402	(1.07)
52	289	7.61	16	210.89	78.11	0	(3.03)	43.39	34.72	1.98	1.72	10.91	4.35	4.77	17.40	0.064897	(1.13)
53	273	7.18	16	202.50	70.50	0	(2.87)	40.36	30.14	1.72	1.50	10.04	4.01	4.50	16.04	0.061572	(1.18)
54	257	6.76	16	193.68	63.32	0	(2.70)	37.49	25.83	1.47	1.28	9.21	3.67	4.24	14.72	0.058417	(1.23)
55	241	6.34	15	184.45	56.55	0	(2.53)	34.79	21.76	1.24	1.08	8.41	3.36	3.98	13.47	0.055424	(1.20)
56	226	5.95	16	175.79	50.21	0	(2.37)	32.26	17.95	1.02	0.89	7.65	3.05	3.73	12.27	0.052584	(1.33)
57	210	5.53	15	165.74	44.26	0	(2.20)	29.89	14.37	0.82	0.71	6.90	2.75	3.47	11.08	0.049890	(1.28)
58	195	5.13	14	156.26	38.74	0	(2.05)	27.69	11.05	0.63	0.55	6.18	2.47	3.22	9.95	0.047334	(1.23)
59	181	4.76	14	147.39	33.61	0	(1.90)	25.64	7.97	0.45	0.40	5.51	2.20	2.99	8.90	0.044909	(1.27)
60	167	4.39	14	138.16	28.84	0	(1.75)	23.74	5.10	0.29	0.25	4.88	1.95	2.76	7.89	0.042608	(1.30)
61	153	4.03	13	128.55	24.45	0	(1.61)	21.99	2.46	0.14	0.12	4.25	1.70	2.52	6.90	0.040425	(1.24)
62	140	3.68	13	119.58	20.42	0	(1.47)	20.38	0.04	0.00	0.00	3.68	1.47	2.31	5.99	0.038353	(1.26)
63	127	3.34	12	110.26	16.74	0	(1.33)	18.91	(2.17)	(0.12)	(0.11)	3.15	1.26	2.10	5.14	0.036388	(1.19)
64	115	3.03	12	101.61	13.39	0	(1.21)	17.58	(4.19)	(0.24)	(0.21)	2.62	1.05	1.90	4.32	0.034524	(1.21)
65	103	2.71	12	92.63	10.37	0	(1.08)	16.37	(6.00)	(0.34)	(0.30)	2.15	0.86	1.70	3.55	0.032755	(1.23)
66	91	2.39	10	83.34	7.66	0	(0.96)	15.29	(7.63)	(0.44)	(0.38)	1.65	0.66	1.50	2.77	0.031077	(1.04)
67	81	2.13	11	75.74	5.26	0	(0.85)	14.33	(9.07)	(0.52)	(0.45)	1.27	0.51	1.34	2.16	0.029484	(1.17)
68	70	1.84	10	66.87	3.13	0	(0.73)	13.48	(10.35)	(0.59)	(0.51)	0.87	0.35	1.16	1.52	0.027974	(1.08)
69	60	1.58	9	58.71	1.29	0	(0.63)	12.75	(11.46)	(0.65)	(0.57)	0.50	0.20	0.99	0.92	0.026540	(0.98)
70	51	1.34	9	51.29	(0.29)	0	(0.54)	12.12	(12.41)	(0.71)	(0.62)	0.15	0.06	0.84	0.37	0.025181	(0.99)
71	42	1.11	8	43.63	(1.63)	0	(0.44)	11.58	(13.21)	(0.75)	(0.66)	(0.14)	(0.06)	0.69	(0.11)	0.023890	(0.89)
72	34	0.89	8	36.74	(2.74)	0	(0.36)	11.14	(13.88)	(0.79)	(0.69)	(0.42)	(0.17)	0.56	(0.56)	0.022666	(0.90)
73	26	0.68	8	29.63	(3.63)	0	(0.27)	10.78	(14.41)	(0.82)	(0.71)	(0.68)	(0.27)	0.43	(0.96)	0.021505	(0.91)
74	18	0.47	7	22.32	(4.32)	0	(0.19)	10.51	(14.83)	(0.85)	(0.74)	(0.94)	(0.38)	0.30	(1.39)	0.020403	(0.81)
75	11	0.29	8	15.79	(4.79)	0	(0.12)	10.32	(15.11)	(0.86)	(0.75)	(1.15)	(0.46)	0.18	(1.72)	0.019358	(0.93)
76	3	0.08	3	8.08	(5.08)	0	(0.03)	10.20	(15.28)	(0.87)	(0.76)	(1.37)	(0.55)	0.05	(2.08)	0.018366	(0.35)
77	0	0.00	0	5.16	(5.16)	0	0.00	10.17	(15.33)	(0.88)	(0.76)	(1.46)	(0.58)	0.00	(2.22)	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00

P.V. OF REV. RQMT 1,291.39 SUM OF 87.58

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,291.39
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	113.11
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,404.50
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	92.12
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	9.21%

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	DISTRIBUTION TRANSFORMERS
BOOK LIFE	33
IOWA CURVE	0.5
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	994	30.12	11	0.00	994.00	38.46	3.33	0	994.00	56.75	49.31	86.08	34.34	16.40	190.25	0.948764	8.50
2	983	29.79	12	19.12	963.88	74.04	17.65	3.33	960.55	54.84	47.65	46.98	18.74	16.22	184.89	0.900153	8.69
3	971	29.42	12	36.91	934.09	68.48	15.58	20.98	913.11	52.13	45.30	47.67	19.02	16.02	177.47	0.854032	8.13
4	959	29.06	12	54.33	904.67	63.35	13.68	36.56	868.11	49.56	43.07	48.17	19.22	15.82	170.41	0.810275	7.61
5	947	28.70	12	71.39	875.61	58.6	11.93	50.24	825.37	47.12	40.94	48.49	19.34	15.63	163.66	0.768760	7.11
6	935	28.33	13	88.09	846.91	54.2	10.32	62.17	784.74	44.80	38.93	48.67	19.42	15.43	157.23	0.729372	7.19
7	922	27.94	13	103.42	818.58	50.14	8.86	72.49	746.09	42.60	37.01	48.68	19.42	15.21	151.04	0.692002	6.70
8	909	27.55	12	118.36	790.64	46.38	7.51	81.35	709.29	40.50	35.19	48.54	19.36	15.00	145.11	0.656546	5.76
9	897	27.18	13	133.91	763.09	45.76	7.41	88.86	674.23	38.50	33.45	45.47	18.14	14.80	139.48	0.622907	5.81
10	884	26.79	13	148.09	735.91	45.76	7.57	96.27	639.64	36.52	31.73	41.79	16.67	14.59	133.87	0.590992	5.39
11	871	26.39	14	161.88	709.12	45.76	7.73	103.84	605.28	34.56	30.03	38.14	15.22	14.37	128.30	0.560712	5.38
12	857	25.97	13	174.27	682.73	45.76	7.90	111.57	571.16	32.61	28.33	34.47	13.75	14.14	122.70	0.531983	4.62
13	844	25.58	14	187.24	656.76	45.76	8.05	119.47	537.29	30.68	26.65	30.85	12.31	13.93	117.20	0.504727	4.60
14	830	25.15	13	198.82	631.18	45.76	8.22	127.52	503.66	28.76	24.99	27.24	10.87	13.70	111.69	0.478867	3.93
15	817	24.76	14	210.97	606.03	45.76	8.38	135.74	470.29	26.85	23.33	23.67	9.44	13.48	106.24	0.454331	3.89
16	803	24.33	15	221.73	581.27	45.76	8.55	144.12	437.15	24.96	21.69	20.10	8.02	13.25	100.80	0.431053	3.82
17	788	23.88	14	231.06	556.94	45.76	8.73	152.67	404.27	23.08	20.05	16.52	6.59	13.00	95.33	0.408968	3.26
18	774	23.45	15	240.94	533.06	45.76	8.90	161.40	371.66	21.22	18.44	13.00	5.19	12.77	89.97	0.388014	3.18
19	759	23.00	15	249.39	509.61	45.76	9.08	170.30	339.31	19.37	16.83	9.47	3.78	12.52	84.58	0.368134	2.88
20	744	22.55	15	257.39	486.61	45.76	9.26	179.38	307.23	17.54	15.24	5.97	2.38	12.28	79.25	0.349272	2.59
21	729	22.09	15	264.94	464.06	22.88	0.31	188.64	275.42	15.73	13.66	25.37	10.12	12.03	73.94	0.331377	2.33
22	714	21.64	16	272.03	441.97	0	(8.63)	188.95	253.02	14.45	12.55	45.68	18.22	11.78	70.01	0.314398	2.21

23	698	21.15	16	277.67	420.33	0	(8.44)	180.32	240.01	13.70	11.91	43.94	17.53	11.52	67.37	0.298290	1.95
24	682	20.67	17	282.82	399.18	0	(8.24)	171.88	227.30	12.98	11.28	42.27	16.86	11.25	64.80	0.283006	1.81
25	665	20.15	16	286.48	378.52	0	(8.04)	163.64	214.88	12.27	10.66	40.56	16.18	10.97	62.19	0.268506	1.48
26	649	19.67	17	290.64	358.36	0	(7.85)	155.60	202.76	11.58	10.06	38.93	15.53	10.71	59.70	0.254749	1.33
27	632	19.15	18	293.30	338.70	0	(7.64)	147.75	190.95	10.90	9.47	37.29	14.88	10.43	57.19	0.241697	1.18
28	614	18.61	17	294.45	319.55	0	(7.42)	140.11	179.44	10.24	8.90	35.65	14.22	10.13	54.68	0.229313	0.90
29	597	18.09	18	296.06	300.94	0	(7.22)	132.69	168.25	9.61	8.35	34.07	13.59	9.85	52.27	0.217564	0.74
30	579	17.55	18	296.15	282.85	0	(7.00)	125.47	157.38	8.99	7.81	32.50	12.97	9.55	49.87	0.206417	0.54
31	561	17.00	19	295.70	265.30	0	(6.78)	118.47	146.83	8.38	7.28	30.95	12.35	9.26	47.49	0.195841	0.37
32	542	16.42	18	293.70	248.30	0	(6.55)	111.69	136.61	7.80	6.78	29.41	11.73	8.94	45.12	0.185807	0.17
33	524	15.88	19	292.12	231.88	0	(6.33)	105.14	126.74	7.24	6.29	27.93	11.14	8.65	42.87	0.176287	0.00
34	505	15.30	19	289.00	216.00	0	(6.10)	98.81	117.19	6.69	5.81	26.44	10.55	8.33	40.58	0.167255	(0.17)
35	486	14.73	19	285.30	200.70	0	(5.88)	92.71	107.99	6.17	5.36	24.98	9.97	8.02	38.37	0.158685	(0.33)
36	467	14.15	19	281.03	185.97	0	(5.65)	86.83	99.14	5.66	4.92	23.56	9.40	7.71	36.19	0.150555	(0.49)
37	448	13.58	20	276.18	171.82	0	(5.42)	81.18	90.64	5.17	4.50	22.17	8.84	7.39	34.06	0.142841	(0.67)
38	428	12.97	19	269.76	158.24	0	(5.17)	75.76	82.48	4.71	4.09	20.81	8.30	7.06	31.96	0.135522	(0.77)
39	409	12.39	19	263.73	145.27	0	(4.94)	70.59	74.68	4.26	3.70	19.49	7.78	6.75	29.94	0.128579	(0.91)
40	390	11.82	20	257.12	132.88	0	(4.71)	65.65	67.23	3.84	3.34	18.21	7.26	6.44	27.99	0.121991	(1.09)
41	370	11.21	19	248.94	121.06	0	(4.47)	60.94	60.12	3.43	2.98	16.92	6.75	6.11	26.01	0.115740	(1.15)
42	351	10.64	20	241.15	109.85	0	(4.24)	56.47	53.38	3.05	2.65	15.72	6.27	5.79	24.16	0.109810	(1.33)
43	331	10.03	19	231.79	99.21	0	(4.00)	52.23	46.98	2.68	2.33	14.49	5.78	5.46	22.28	0.104184	(1.37)
44	312	9.45	19	222.82	89.18	0	(3.77)	48.23	40.95	2.34	2.03	13.35	5.33	5.15	20.53	0.098846	(1.47)
45	293	8.88	18	213.27	79.73	0	(3.54)	44.46	35.27	2.01	1.75	12.23	4.88	4.83	18.81	0.093782	(1.49)
46	275	8.33	19	204.15	70.85	0	(3.32)	40.92	29.93	1.71	1.48	11.19	4.46	4.54	17.20	0.088976	(1.66)
47	256	7.76	18	193.48	62.52	0	(3.09)	37.60	24.92	1.42	1.24	10.13	4.04	4.22	15.59	0.084418	(1.65)
48	238	7.21	18	183.24	54.76	0	(2.88)	34.51	20.25	1.16	1.00	9.14	3.65	3.93	14.07	0.080092	(1.73)
49	220	6.67	17	172.45	47.55	0	(2.66)	31.63	15.92	0.91	0.79	8.18	3.26	3.63	12.60	0.075989	(1.71)
50	203	6.15	17	162.12	40.88	0	(2.45)	28.97	11.91	0.68	0.59	7.29	2.91	3.35	11.23	0.072095	(1.77)
51	186	5.64	16	151.27	34.73	0	(2.25)	26.52	8.21	0.47	0.41	6.42	2.56	3.07	9.90	0.068402	(1.73)
52	170	5.15	16	140.91	29.09	0	(2.06)	24.27	4.82	0.28	0.24	5.61	2.24	2.81	8.66	0.064897	(1.78)
53	154	4.67	16	130.06	23.94	0	(1.86)	22.21	1.73	0.10	0.09	4.84	1.93	2.54	7.47	0.061572	(1.84)
54	138	4.18	14	118.73	19.27	0	(1.67)	20.35	(1.08)	(0.06)	(0.05)	4.08	1.63	2.28	6.31	0.058417	(1.65)
55	124	3.76	14	108.91	15.09	0	(1.50)	18.68	(3.59)	(0.20)	(0.18)	3.42	1.36	2.05	5.29	0.055424	(1.69)
56	110	3.33	14	98.67	11.33	0	(1.33)	17.18	(5.85)	(0.33)	(0.29)	2.78	1.11	1.82	4.31	0.052584	(1.73)
57	96	2.91	12	88.00	8.00	0	(1.16)	15.85	(7.85)	(0.45)	(0.39)	2.16	0.86	1.58	3.35	0.049890	(1.52)
58	84	2.55	12	78.91	5.09	0	(1.02)	14.69	(9.60)	(0.55)	(0.48)	1.62	0.65	1.39	2.54	0.047334	(1.55)
59	72	2.18	12	69.45	2.55	0	(0.87)	13.67	(11.12)	(0.64)	(0.55)	1.12	0.45	1.19	1.76	0.044909	(1.58)
60	60	1.82	10	59.64	0.36	0	(0.73)	12.80	(12.44)	(0.71)	(0.62)	0.63	0.25	0.99	1.00	0.042608	(1.34)
61	50	1.52	10	51.45	(1.45)	0	(0.60)	12.07	(13.52)	(0.77)	(0.67)	0.24	0.10	0.83	0.41	0.040425	(1.36)
62	40	1.21	10	42.97	(2.97)	0	(0.48)	11.47	(14.44)	(0.82)	(0.72)	(0.15)	(0.06)	0.66	(0.21)	0.038353	(1.38)
63	30	0.91	9	34.18	(4.18)	0	(0.36)	10.99	(15.17)	(0.87)	(0.75)	(0.53)	(0.21)	0.50	(0.78)	0.036388	(1.26)
64	21	0.64	9	26.09	(5.09)	0	(0.25)	10.63	(15.72)	(0.90)	(0.78)	(0.85)	(0.34)	0.35	(1.28)	0.034524	(1.28)
65	12	0.36	8	17.73	(5.73)	0	(0.15)	10.38	(16.11)	(0.92)	(0.80)	(1.18)	(0.47)	0.20	(1.78)	0.032755	(1.15)
66	4	0.12	4	10.09	(6.09)	0	(0.05)	10.23	(16.32)	(0.93)	(0.81)	(1.43)	(0.57)	0.07	(2.17)	0.031077	(0.58)
67	0	0.00	0	6.21	(6.21)	0	0.00	10.18	(16.39)	(0.94)	(0.81)	(1.56)	(0.62)	0.00	(2.37)	0.029484	0.00
68	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.027974	0.00
69	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.026540	0.00
70	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.025181	0.00
71	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.023890	0.00
72	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.022666	0.00
73	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.021505	0.00
74	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.020403	0.00
75	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.019358	0.00
76	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.018366	0.00
77	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00
													P.V. OF REV. RQMT		1,292.30	SUM OF	80.91

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,292.30
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	104.56
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,396.87
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	96.16
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	9.62%

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	DISTRIBUTION (METERS)
BOOK LIFE	30
IOWA CURVE	0.5
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

YEAR	(1) MEAN ANNUAL SURVI-VORS	(2) BOOK DEPR	(3) RETIRE-MENTS	(4) BOOK ACCUM DEPR	(5) MEAN NET BOOK INVEST-MENT	(6) TAX DEPR	(7) DEFERRED INCOME TAX	(8) DEFERRED TAX RESERVE	(9) MEAN NET INVEST-MENT	(10) EQUITY	(11) INTEREST	(12) TAXABLE INCOME	(13) INCOME TAX	(14) PROP. TAX	(15) REV. RQMT.	(16) MULTI-PLIER #2	(17) YEARLY VALUE OF DISPERSED RETIRE
1	1,000	33.33	2	0.00	1,000.00	38.46	2.05	0	1,000.00	57.10	49.61	89.88	35.86	16.50	194.45	0.948764	1.48
2	998	33.27	3	31.33	966.67	74.04	16.27	2.05	964.62	55.07	47.85	50.85	20.29	16.47	189.22	0.900153	2.08
3	995	33.17	4	61.60	933.40	68.48	14.09	18.32	915.08	52.25	45.40	51.62	20.59	16.42	181.92	0.854032	2.59
4	991	33.03	5	90.77	900.23	63.35	12.09	32.41	867.82	49.55	43.05	52.11	20.79	16.35	174.86	0.810275	3.02
5	986	32.87	7	118.80	867.20	58.6	10.27	44.50	822.70	46.97	40.81	52.42	20.91	16.27	168.10	0.768760	3.94
6	979	32.63	7	144.67	834.33	54.2	8.60	54.77	779.56	44.51	38.67	52.48	20.94	16.15	161.50	0.729372	3.66
7	972	32.40	9	170.30	801.70	50.14	7.08	63.37	738.33	42.15	36.63	52.39	20.90	16.04	155.20	0.692002	4.37
8	963	32.10	10	193.70	769.30	46.38	5.70	70.45	698.85	39.90	34.67	52.11	20.79	15.89	149.05	0.656546	4.50
9	953	31.77	12	215.80	737.20	45.76	5.58	76.15	661.05	37.74	32.79	48.79	19.46	15.72	143.06	0.622907	5.00
10	941	31.37	12	235.57	705.43	45.76	5.74	81.73	623.70	35.61	30.94	44.85	17.89	15.53	137.08	0.590992	4.61
11	929	30.97	14	254.93	674.07	45.76	5.90	87.47	586.60	33.49	29.10	40.92	16.32	15.33	131.11	0.560712	4.96
12	915	30.50	15	271.90	643.10	45.76	6.09	93.37	549.73	31.39	27.27	36.97	14.75	15.10	125.10	0.531983	4.88
13	900	30.00	16	287.40	612.60	45.76	6.29	99.46	513.14	29.30	25.46	32.99	13.16	14.85	119.06	0.504727	4.77
14	884	29.47	18	301.40	582.60	45.76	6.50	105.75	476.85	27.23	23.66	29.01	11.57	14.59	113.02	0.478867	4.90
15	866	28.87	18	312.87	553.13	45.76	6.74	112.25	440.88	25.17	21.87	24.98	9.97	14.29	106.91	0.454331	4.46
16	848	28.27	19	323.73	524.27	45.76	6.98	118.99	405.28	23.14	20.10	21.01	8.38	13.99	100.86	0.431053	4.27
17	829	27.63	20	333.00	496.00	45.76	7.23	125.97	370.03	21.13	18.36	17.03	6.79	13.68	94.82	0.408968	4.05
18	809	26.97	22	340.63	468.37	45.76	7.50	133.20	335.17	19.14	16.63	13.05	5.21	13.35	88.80	0.388014	4.00
19	787	26.23	22	345.60	441.40	45.76	7.79	140.70	300.70	17.17	14.92	9.04	3.61	12.99	82.71	0.368134	3.56
20	765	25.50	22	349.83	415.17	45.76	8.08	148.49	266.68	15.23	13.23	5.07	2.02	12.62	76.68	0.349272	3.14
21	743	24.77	24	353.33	389.67	22.88	(0.75)	156.57	233.10	13.31	11.56	24.04	9.59	12.26	70.74	0.331377	3.00
22	719	23.97	24	354.10	364.90	0	(9.56)	155.82	209.08	11.94	10.37	43.83	17.49	11.86	66.07	0.314398	2.59

23	695	23.17	25	354.07	340.93	0	(9.24)	146.26	194.67	11.11	9.66	41.65	16.62	11.47	62.79	0.298290	2.30
24	670	22.33	25	352.23	317.77	0	(8.91)	137.02	180.75	10.32	8.97	39.50	15.76	11.06	59.53	0.283006	1.91
25	645	21.50	26	349.57	295.43	0	(8.58)	128.11	167.32	9.55	8.30	37.38	14.91	10.64	56.32	0.268506	1.61
26	619	20.63	26	345.07	273.93	0	(8.23)	119.53	154.40	8.82	7.66	35.31	14.09	10.21	53.18	0.254749	1.26
27	593	19.77	26	339.70	253.30	0	(7.89)	111.30	142.00	8.11	7.04	33.25	13.26	9.78	50.07	0.241697	0.92
28	567	18.90	27	333.47	233.53	0	(7.54)	103.41	130.12	7.43	6.46	31.26	12.47	9.36	47.08	0.229313	0.62
29	540	18.00	27	325.37	214.63	0	(7.18)	95.87	118.76	6.78	5.89	29.28	11.68	8.91	44.08	0.217564	0.30
30	513	17.10	26	316.37	196.63	0	(6.82)	88.69	107.94	6.16	5.35	27.35	10.91	8.46	41.16	0.206417	0.00
31	487	16.23	27	307.47	179.53	0	(6.48)	81.87	97.66	5.58	4.84	25.51	10.18	8.04	38.39	0.195841	(0.29)
32	460	15.33	27	296.70	163.30	0	(6.12)	75.39	87.91	5.02	4.36	23.68	9.45	7.59	35.63	0.185807	(0.56)
33	433	14.43	26	285.03	147.97	0	(5.76)	69.27	78.70	4.49	3.90	21.90	8.74	7.14	32.94	0.176287	(0.78)
34	407	13.57	26	273.47	133.53	0	(5.41)	63.51	70.02	4.00	3.47	20.23	8.07	6.72	30.42	0.167255	(1.02)
35	381	12.70	26	261.03	119.97	0	(5.07)	58.10	61.87	3.53	3.07	18.57	7.41	6.29	27.93	0.158685	(1.24)
36	355	11.83	25	247.73	107.27	0	(4.72)	53.03	54.24	3.10	2.69	16.99	6.78	5.86	25.54	0.150555	(1.40)
37	330	11.00	25	234.57	95.43	0	(4.39)	48.31	47.12	2.69	2.34	15.47	6.17	5.45	23.26	0.142841	(1.59)
38	305	10.17	24	220.57	84.43	0	(4.06)	43.92	40.51	2.31	2.01	14.00	5.59	5.03	21.05	0.135522	(1.70)
39	281	9.37	23	206.73	74.27	0	(3.74)	39.86	34.41	1.96	1.71	12.62	5.03	4.64	18.97	0.128579	(1.79)
40	258	8.60	23	193.10	64.90	0	(3.43)	36.12	28.78	1.64	1.43	11.33	4.52	4.26	17.02	0.121991	(1.94)
41	235	7.83	22	178.70	56.30	0	(3.13)	32.69	23.61	1.35	1.17	10.07	4.02	3.88	15.12	0.115740	(1.99)
42	213	7.10	21	164.53	48.47	0	(2.83)	29.56	18.91	1.08	0.94	8.90	3.55	3.51	13.35	0.109810	(2.03)
43	192	6.40	21	150.63	41.37	0	(2.55)	26.73	14.64	0.84	0.73	7.80	3.11	3.17	11.70	0.104184	(2.15)
44	171	5.70	19	136.03	34.97	0	(2.27)	24.18	10.79	0.62	0.54	6.74	2.69	2.82	10.10	0.098846	(2.04)
45	152	5.07	18	122.73	29.27	0	(2.02)	21.91	7.36	0.42	0.36	5.77	2.30	2.51	8.64	0.093782	(2.03)
46	134	4.47	18	109.80	24.20	0	(1.78)	19.89	4.31	0.25	0.21	4.89	1.95	2.21	7.31	0.088976	(2.11)
47	116	3.87	16	96.27	19.73	0	(1.54)	18.11	1.62	0.09	0.08	4.02	1.60	1.91	6.01	0.084418	(1.95)
48	100	3.33	15	84.13	15.87	0	(1.33)	16.57	(0.70)	(0.04)	(0.03)	3.27	1.30	1.65	4.88	0.080092	(1.89)
49	85	2.83	13	72.47	12.53	0	(1.13)	15.24	(2.71)	(0.15)	(0.13)	2.58	1.03	1.40	3.85	0.075989	(1.70)
50	72	2.40	13	62.30	9.70	0	(0.96)	14.11	(4.41)	(0.25)	(0.22)	1.98	0.79	1.19	2.95	0.072095	(1.75)
51	59	1.97	11	51.70	7.30	0	(0.78)	13.15	(5.85)	(0.33)	(0.29)	1.43	0.57	0.97	2.11	0.068402	(1.52)
52	48	1.60	11	42.67	5.33	0	(0.64)	12.37	(7.04)	(0.40)	(0.35)	0.93	0.37	0.79	1.37	0.064897	(1.56)
53	37	1.23	9	33.27	3.73	0	(0.49)	11.73	(8.00)	(0.46)	(0.40)	0.47	0.19	0.61	0.68	0.061572	(1.30)
54	28	0.93	7	25.50	2.50	0	(0.37)	11.24	(8.74)	(0.50)	(0.43)	0.11	0.04	0.46	0.13	0.058417	(1.04)
55	21	0.70	7	19.43	1.57	0	(0.28)	10.87	(9.30)	(0.53)	(0.46)	(0.18)	(0.07)	0.35	(0.29)	0.055424	(1.06)
56	14	0.47	5	13.13	0.87	0	(0.19)	10.59	(9.72)	(0.56)	(0.48)	(0.47)	(0.19)	0.23	(0.72)	0.052584	(0.77)
57	9	0.30	4	8.60	0.40	0	(0.12)	10.40	(10.00)	(0.57)	(0.50)	(0.65)	(0.26)	0.15	(1.00)	0.049890	(0.63)
58	5	0.17	3	4.90	0.10	0	(0.07)	10.28	(10.18)	(0.58)	(0.51)	(0.80)	(0.32)	0.08	(1.23)	0.047334	(0.48)
59	2	0.07	2	2.07	(0.07)	0	(0.03)	10.21	(10.28)	(0.59)	(0.51)	(0.92)	(0.37)	0.03	(1.40)	0.044909	(0.32)
60	0	0.00	0	0.13	(0.13)	0	0.00	10.18	(10.31)	(0.59)	(0.51)	(0.98)	(0.39)	0.00	(1.49)	0.042608	0.00
61	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.040425	0.00
62	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.038353	0.00
63	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.036388	0.00
64	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.034524	0.00
65	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.032755	0.00
66	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.031077	0.00
67	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.029484	0.00
68	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.027974	0.00
69	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.026540	0.00
70	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.025181	0.00
71	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.023890	0.00
72	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.022666	0.00
73	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.021505	0.00
74	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.020403	0.00
75	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.019358	0.00
76	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.018366	0.00
77	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00

P.V. OF REV. RQMT 1,310.45 SUM OF 52.15

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,310.45
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	68.34
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,378.79
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	98.52
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	9.85%

CALCULATION OF PRESENT VALUE OF CARRYING CHARGE

ASSUMPTIONS

TYPE OF PLANT	DISTRIBUTION (STREET LIGHTING)
BOOK LIFE	15
IOWA CURVE	0.5
TAX LIFE	20
INCOME TAX RATE	39.8938%
P. TAX,INS.A&G	1.6500%
TAX BASIS	100.5400%

COST OF CAPITAL:	%	COST	WEIGHTED COST
DEBT	52.00%	9.54%	4.9608%
PREFFERED EQUITY	7.90%	7.30%	0.5767%
COMMON EQUITY	40.10%	12.80%	5.1328%
			10.6703%

INFLATION 5.00%

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
YEAR	MEAN ANNUAL SURVI-VORS	BOOK DEPR	RETIRE-MENTS	BOOK ACCUM DEPR	MEAN NET BOOK INVEST-MENT	TAX DEPR	DEFERRED INCOME TAX	DEFERRED TAX RESERVE	MEAN NET INVEST-MENT	EQUITY	INTEREST	TAXABLE INCOME	INCOME TAX	PROP. TAX	REV. RQMT.	MULTI-PLIER #2	YEARLY VALUE OF DISPERSED RETIRE
1	987	65.80	26	0.00	987.00	38.46	(10.91)	0	987.00	56.35	48.96	121.09	48.31	16.29	224.80	0.948764	12.86
2	961	64.07	26	39.80	921.20	74.04	3.98	(10.91)	932.11	53.22	46.24	78.57	31.34	15.86	214.71	0.900153	11.59
3	935	62.33	28	77.87	857.13	68.48	2.45	(6.93)	864.06	49.33	42.86	75.92	30.29	15.43	202.69	0.854032	11.19
4	907	60.47	28	112.20	794.80	63.35	1.15	(4.48)	799.28	45.63	39.65	73.03	29.13	14.97	191.00	0.810275	9.97
5	879	58.60	30	144.67	734.33	58.6	0.00	(3.33)	737.66	42.12	36.59	70.08	27.96	14.50	179.77	0.768760	9.43
6	849	56.60	30	173.27	675.73	54.2	(0.96)	(3.33)	679.06	38.77	33.69	66.90	26.69	14.01	168.80	0.729372	8.25
7	819	54.60	31	199.87	619.13	50.14	(1.78)	(4.29)	623.42	35.59	30.93	63.67	25.40	13.51	158.25	0.692002	7.37
8	788	52.53	32	223.47	564.53	46.38	(2.45)	(6.07)	570.60	32.58	28.31	60.37	24.08	13.00	148.05	0.656546	6.47
9	756	50.40	33	244.00	512.00	45.76	(1.85)	(8.52)	520.52	29.72	25.82	54.09	21.58	12.47	138.14	0.622907	5.56
10	723	48.20	35	261.40	461.60	45.76	(0.97)	(10.37)	471.97	26.95	23.41	47.28	18.86	11.93	128.38	0.590992	4.78
11	688	45.87	36	274.60	413.40	45.76	(0.04)	(11.34)	424.74	24.25	21.07	40.46	16.14	11.35	118.64	0.560712	3.83
12	652	43.47	38	284.47	367.53	45.76	0.91	(11.38)	378.91	21.63	18.80	33.68	13.44	10.76	109.01	0.531983	2.95
13	614	40.93	39	289.93	324.07	45.76	1.93	(10.47)	334.54	19.10	16.60	26.96	10.76	10.13	99.45	0.504727	1.97
14	575	38.33	40	291.87	283.13	45.76	2.96	(8.54)	291.67	16.65	14.47	20.27	8.09	9.49	89.99	0.478867	0.98
15	535	35.67	41	290.20	244.80	45.76	4.03	(5.58)	250.38	14.30	12.42	13.70	5.47	8.83	80.72	0.454331	0.00
16	494	32.93	42	284.87	209.13	45.76	5.12	(1.55)	210.68	12.03	10.45	7.19	2.87	8.15	71.55	0.431053	(0.98)
17	452	30.13	43	275.80	176.20	45.76	6.23	3.57	172.63	9.86	8.56	0.77	0.31	7.46	62.55	0.408968	(1.95)
18	409	27.27	43	262.93	146.07	45.76	7.38	9.80	136.27	7.78	6.76	(5.55)	(2.21)	6.75	53.73	0.388014	(2.85)
19	366	24.40	42	247.20	118.80	45.76	8.52	17.18	101.62	5.80	5.04	(11.71)	(4.67)	6.04	45.13	0.368134	(3.62)
20	324	21.60	42	229.60	94.40	45.76	9.64	25.70	68.70	3.92	3.41	(17.64)	(7.04)	5.35	36.88	0.349272	(4.41)
21	282	18.80	40	209.20	72.80	22.88	1.63	35.34	37.46	2.14	1.86	(0.52)	(0.21)	4.65	28.87	0.331377	(4.92)
22	242	16.13	39	188.00	54.00	0	(6.44)	36.97	17.03	0.97	0.84	17.74	7.08	3.99	22.57	0.314398	(5.46)

23	203	13.53	37	165.13	37.87	0	(5.40)	30.53	7.34	0.42	0.36	14.23	5.68	3.35	17.94	0.298290	(5.77)
24	166	11.07	34	141.67	24.33	0	(4.41)	25.13	(0.80)	(0.05)	(0.04)	10.99	4.38	2.74	13.69	0.283006	(5.83)
25	132	8.80	30	118.73	13.27	0	(3.51)	20.72	(7.45)	(0.43)	(0.37)	8.09	3.23	2.18	9.90	0.268506	(5.57)
26	102	6.80	28	97.53	4.47	0	(2.71)	17.21	(12.74)	(0.73)	(0.63)	5.59	2.23	1.68	6.64	0.254749	(5.59)
27	74	4.93	24	76.33	(2.33)	0	(1.97)	14.50	(16.83)	(0.96)	(0.84)	3.33	1.33	1.22	3.71	0.241697	(5.10)
28	50	3.33	22	57.27	(7.27)	0	(1.33)	12.53	(19.80)	(1.13)	(0.98)	1.45	0.58	0.83	1.30	0.229313	(4.95)
29	28	1.87	19	38.60	(10.60)	0	(0.74)	11.20	(21.80)	(1.24)	(1.08)	(0.19)	(0.08)	0.46	(0.81)	0.217564	(4.50)
30	9	0.60	9	21.47	(12.47)	0	(0.24)	10.46	(22.93)	(1.31)	(1.14)	(1.58)	(0.63)	0.15	(2.57)	0.206417	(2.23)
31	0	0.00	0	13.07	(13.07)	0	0.00	10.22	(23.29)	(1.33)	(1.16)	(2.21)	(0.88)	0.00	(3.37)	0.195841	0.00
32	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.185807	0.00
33	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.176287	0.00
34	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.167255	0.00
35	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.158685	0.00
36	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.150555	0.00
37	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.142841	0.00
38	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.135522	0.00
39	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.128579	0.00
40	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.121991	0.00
41	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.115740	0.00
42	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.109810	0.00
43	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.104184	0.00
44	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.098846	0.00
45	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.093782	0.00
46	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.088976	0.00
47	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.084418	0.00
48	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.080092	0.00
49	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.075989	0.00
50	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.072095	0.00
51	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.068402	0.00
52	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.064897	0.00
53	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.061572	0.00
54	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.058417	0.00
55	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.055424	0.00
56	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.052584	0.00
57	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.049890	0.00
58	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.047334	0.00
59	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.044909	0.00
60	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.042608	0.00
61	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.040425	0.00
62	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.038353	0.00
63	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.036388	0.00
64	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.034524	0.00
65	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.032755	0.00
66	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.031077	0.00
67	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.029484	0.00
68	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.027974	0.00
69	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.026540	0.00
70	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.025181	0.00
71	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.023890	0.00
72	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.022666	0.00
73	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.021505	0.00
74	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.020403	0.00
75	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.019358	0.00
76	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.018366	0.00
77	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.017425	0.00
78	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.016532	0.00

79	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.015685	0.00
80	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014881	0.00
81	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.014119	0.00
82	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.013395	0.00
83	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012709	0.00
84	0	0.00	0	0.00	0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.012058	0.00

P.V. OF REV. RQMT 1,293.77 SUM OF 33.47

(1)	PRESENT VALUE OF REVENUE REQUIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	1,293.77
(2)	PRESENT VALUE COST OF REPLACING DISPURSED RETIREMENTS RELATED TO INCREMENTAL $1,000 INVESTMENT	43.30
(3)	TOTAL PRESENT VALUE COST RELATED TO INCREMENTAL $1,000 INVESTMENT (1)+(2)	1,337.07
(4)	ANNUAL ECONOMIC CHARGE IN CONSTANT DOLLARS RELATED TO INCREMENTAL $1,000 INVESTMENT	138.94
(5)	ANNUAL ECONOMIC CHARGE RELATED TO INCREMENTAL INVESTMENT [(4)/$1,000]	13.89%

CENTRAL MAINE POWER COMPANY
Computation of Demand-Related
Generation, Transmission and Distribution CP Unit Cost

			Generation	Transmission			Distribution	
				345 kV	115 kV	34 kV	Primary	Secondary
			(1990 Dollars per Kilowatt)					
			(1)	(2)	(3)	(4)	(5)	(6)
(1)	Long-run Unit Investment	[a]	$ 472.00	$ 59.00	$ 346.00	$ 27.00	$ 290.00	$ 247.00
(2)	With General Plant Loading (1)x1.082	[a]	510.70	63.84	374.37	29.21	313.78	267.25
(3)	Annual Economic Charge Related to Capital Investment	[b]	10.33 %	9.44 %	8.86 %	8.86 %	9.47 %	9.47 %
(4)	A&G Loading	[a]	0.24	0.24	0.24	0.24	0.24	0.24
(5)	Total Annual Carrying Charge (3)+(4)		10.57 %	9.68 %	9.10 %	9.10 %	9.71 %	9.71 %
(6)	Annualized Costs (2)x(5)		$ 53.98	$ 6.18	$ 34.07	$ 2.66	$ 30.50	$ 25.95
(7)	Demand-Related O&M Expenses	[a]	0.61	2.17	1.37	1.52	9.67	4.11
(8)	With A&G Loading (7)x1.3528	[a]	0.83	2.94	1.85	2.06	13.08	5.56
(9)	Demand-Related Cost (6)+(8)		$ 54.80	$ 9.12	$ 35.92	$ 4.71	$ 43.58	$ 31.51
	Working Capital							
(10)	Material and Supplies (2)x1.2%	[a]	$ 6.13	$ 0.77	$ 4.49	$ 0.35	$ 3.77	$ 3.21
(11)	Prepayments (2)x0.45%	[a]	2.30	0.29	1.68	0.13	1.41	1.20
(12)	Cash Working Capital (8)x5.02%	[a]	0.04	0.15	0.09	0.10	0.66	0.28
(13)	Total Working Capital (10)+(11)+(12)		$ 8.47	$ 1.20	$ 6.27	$ 0.59	$ 5.83	$ 4.69
(14)	Revenue Requirement for Working Capital (13)x15.13%	[c]	$ 1.28	$ 0.18	$ 0.95	$ 0.09	$ 0.88	$ 0.71
(15)	Total Demand-Related Costs (9)+(14)		$ 56.08	$ 9.30	$ 36.87	$ 4.80	$ 44.46	$ 32.22
(16)	Total Marginal Costs (Rounded)		$ 56.00	$ 9.00	$ 37.00	$ 5.00	$ 44.00	$ 32.00

[a] Per Exhibit Maheu-25, Schedule 15.
[b] Per Schedule 7, Table A, Line 5.
[c] Includes overall return at 10.67% and federal and state income tax component of 4.46%. The income tax component is estimated at 0.398938/.601062 of the preferred and common equity components.

CENTRAL MAINE POWER COMPANY
COMPUTATION OF ANNUAL MARGINAL UNIT COST
CUSTOMER RELATED

		RESIDENTIAL		GENERAL SERVICE								
		RATES A&E	RATE A-TOU	RATE N SECONDARY	SGS SEC 1-PH	SGS SEC 3-PH	MGS SEC 1-PH	MGS SEC 3-PH	MGS PRI 1-PH	MGS PRI 3-PH	IGS SEC-TOU	IGS PRI-TOU
		(1990 Dollars per Customer)										
(1)	Long Run Customer Related Distribution Investment [a]	$ 105.00	$ 105.00	$ 105.00	$ 105.00	$ 105.00	$ 105.00	$ 105.00	$ 0.00	$ 0.00	$ 105.00	$ 0.00
(2)	With General Plant Loading (1)x1.082 [a]	113.61	113.61	113.61	113.61	113.61	113.61	113.61	0.00	0.00	113.61	0.00
(3)	Annual Economic Charge (%) [b]	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47	9.47
(4)	A&G Loading (%) [a]	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
(5)	Total Annual Carrying Charge (3)+(4)(%)	9.71	9.71	9.71	9.71	9.71	9.71	9.71	9.71	9.71	9.71	9.71
(6)	Annualized Costs (2)x(5)	11.03	11.03	11.03	11.03	11.03	11.03	11.03	0.00	0.00	11.03	0.00
(7)	Meter Investment [a]	50.00	244.00	174.00	75.00	280.00	179.00	430.00	2729.00	6208.00	2381.00	6944.00
(8)	With General Plant Loading (7)x1.082 [a]	54.10	264.01	188.27	81.15	302.96	193.68	465.26	2952.78	6717.06	2576.24	7513.41
(9)	Annual Economic Charge (%) [c]	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85	9.85
(10)	Total Economic Charge (9)+(4)	10.09	10.09	10.09	10.09	10.09	10.09	10.09	10.09	10.09	10.09	10.09
(11)	Annualized Cost (8)x(10)	5.46	26.64	19.00	8.19	30.57	19.54	46.94	297.94	677.75	259.94	758.10
(12)	Service Drop Related O&M Expense [a]	7.71	7.71	7.71	7.71	7.71	7.71	7.71	0.00	0.00	7.71	0.00
(13)	Meter-Related O&M Expense [a]	13.32	25.96	46.35	19.71	56.34	47.69	92.17	268.13	275.86	472.59	472.59
(14)	Customer Accounts Expense [a]	31.57	31.57	31.57	31.57	31.57	85.87	85.87	85.87	85.87	85.87	85.87
(15)	Customer Service and Informational Expense [a]	5.38	5.38	11.62	7.42	7.42	48.69	48.69	48.69	48.69	48.69	48.69
(16)	Total Expense (12)+(13)+(14)+(15)	57.98	70.62	97.25	66.41	103.04	189.96	234.44	402.69	410.42	614.86	607.15
(17)	With A&G Loading (16)x1.3528 [a]	78.44	95.53	131.56	89.84	139.39	256.98	317.15	544.76	555.22	831.78	821.35
(18)	Total Capital and Expense Costs (6)+(11)+(17)	94.93	133.20	161.59	109.06	180.99	287.55	375.13	842.69	1232.97	1102.76	1579.46
	Working Capital											
(19)	Materials and Supplies [(2)+(8)]x1.2% [a]	2.01	4.53	3.62	2.34	5.00	3.69	6.95	35.43	80.60	32.28	90.16
(20)	Prepayments [(2)+(8)]x0.45% [a]	0.75	1.70	1.36	0.88	1.87	1.38	2.60	13.29	30.23	12.10	33.81
(21)	Cash Working Capital (17)x5.02% [m]	3.94	4.80	6.60	4.51	7.00	12.90	15.92	27.35	27.87	41.76	41.23
(22)	Total Working Capital (19)+(20)+(21)	6.70	11.03	11.59	7.72	13.87	17.97	25.47	76.07	138.70	86.14	165.20
(23)	Revenue Requirement for Working Capital (22)x15.13% [d]	1.01	1.67	1.75	1.17	2.10	2.72	3.85	11.51	20.99	13.03	25.00
(24)	Total Customer Related Marginal Costs	95.94	134.87	163.34	110.23	183.09	290.27	378.98	854.20	1253.95	1115.79	1604.45

Notes appear on page 4.

CENTRAL MAINE POWER COMPANY
COMPUTATION OF ANNUAL MARGINAL UNIT COST
CUSTOMER RELATED

		GENERAL SERVICE					
		LGS					
		SEC-TOU	PRI-TOU	ST-TOU	T-TOU	RATE GSS	WHOLESALE RATE W-1
		(1990 Dollars Per Customers)					
(1)	Long Run Customer Related Distribution Investment [a]	$ 105.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
(2)	With General Plant Loading (1)x1.082 [a]	113.61	0.00	0.00	0.00	0.00	0.00
(3)	Annual Economic Charge (%) [b]	9.47	9.47	9.47	9.47	9.47	9.47
(4)	A&G Loading (%) [a]	0.24	0.24	0.24	0.24	0.24	0.24
(5)	Total Annual Carrying Charge (3)+(4)(%)	9.71	9.71	9.71	9.71	9.71	9.71
(6)	Annualized Costs (2)x(5)	11.03	0.00	0.00	0.00	0.00	0.00
(7)	Meter Investment [a]	4,183.00	8,530.00	19,573.00	41,279.00	5,360.00	20,089.00
(8)	With General Plant Loading (7)x1.082 [a]	4,526.01	9,229.46	21,177.99	44,663.88	5,799.52	21,736.30
(9)	Annual Economic Charge (%) [c]	9.85	9.85	9.85	9.85	9.85	9.85
(10)	Total Economic Charge (9)+(4)	10.09	10.09	10.09	10.09	10.09	10.09
(11)	Annualized Cost (8)x(10)	456.67	931.25	2,136.86	4,506.59	585.17	2,193.19
(12)	Service Drop Related O&M Expense [a]	7.71	0.00	0.00	0.00	0.00	0.00
(13)	Meter-Related O&M Expense [a]	895.77	895.77	876.59	1,144.99	288.38	838.36
(14)	Customer Accounts Expense [a]	120.60	120.60	120.60	120.60	77.98	117.12
(15)	Customer Service and Informational Expense [a]	2,669.93	2,669.93	2,669.93	2,669.93	10,994.62	2,728.68
(16)	Total Expense (12)+(13)+(14)+(15)	3,694.01	3,686.30	3,667.12	3,935.52	11,360.98	3,684.16
(17)	With A&G Loading (16)x1.3528 [a]	4,997.26	4,986.83	4,960.88	5,323.97	15,369.13	4,983.93
(18)	Total Capital and Expense Costs (6)+(11)+(17)	5,464.96	5,918.08	7,097.74	9,830.56	15,954.31	7,177.12
	Working Capital						
(19)	Materials and Supplies [(2)+(8)]x1.2% [a]	55.68	110.75	254.14	535.97	69.59	260.84
(20)	Prepayments [(2)+(8)]x0.45% [a]	20.88	41.53	95.30	200.99	26.10	97.81
(21)	Cash Working Capital (17)x5.02% [a]	250.86	250.34	249.04	267.26	771.53	250.19
(22)	Total Working Capital (19)+(20)+(21)	327.42	402.62	598.47	1,004.22	867.22	608.84
(23)	Revenue Requirement for Working Capital (22)x15.13% [d]	49.54	60.92	90.55	151.94	131.21	92.12
(24)	Total Customer Related Marginal Costs	5,514.50	5,979.00	7,188.29	9,982.49	16,085.52	7,269.24

Notes apper on page 4.

CENTRAL MAINE POWER COMPANY
COMPUTATION OF ANNUAL MARGINAL UNIT COST
CUSTOMER RELATED
REBUTTAL FILING

		Lighting Rate AL Secondary	Lighting Rate SL Secondary
		(1990 Dollars per Luminaire)	
(1)	Long Run Customer Related Distribution Investment [a]	$ 0.00	$ 0.00
(2)	With General Plant Loading (1)x1.082 [a]	0.00	0.00
(3)	Annual Economic Charge (%) [b]	9.47	9.47
(4)	A&G Loading (%) [a]	0.24	0.24
(5)	Total Annual Carrying Charge (3)+(4)(%)	9.71	9.71
(6)	Annualized Costs (2)x(5)	0.00	0.00
(7)	Luminaire Investment [a]	246.43	177.82
(8)	With General Plant Loading (7)x1.082 [a]	266.64	192.40
(9)	Annual Economic Charge (%) [e]	13.89	13.89
(10)	Total Economic Charge (9)+(4)	14.13	14.13
(11)	Annualized Cost (8)x(10)	37.68	27.19
(12)	Service Drop Related O&M Expense [a]	7.71	7.71
(13)	Street Lighting O&M Expense [a]	24.90	24.90
(14)	Customer Accounts Expense [a]	15.91	0.16
(15)	Customer Service and Informational Expense [a]	5.65	4.90
(16)	Total Expense (12)+(13)+(14)+(15)	54.17	37.67
(17)	With A&G Loading (16)x1.3528 [a]	73.28	50.96
(18)	Total Capital and Expense Costs (6)+(11)+(17)	110.96	78.15
	Working Capital		
(19)	Materials and Supplies [(2)+(8)]x1.2% [a]	3.20	2.31
(20)	Prepayments [(2)+(8)]x0.45% [a]	1.20	0.87
(21)	Cash Working Capital (17)x5.02% [a]	3.68	2.56
(22)	Total Working Capital (19)+(20)+(21)	8.08	5.73
(23)	Revenue Requirement for Working Capital (22)x15.13% [d]	1.22	0.87
(24)	Total Customer Related Marginal Costs	112.18	79.01

Notes appear on page 4.

FOOTNOTES

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[a] Per Exhibit Maheu-25, Schedule 16.

[b] Per Schedule 7, Table A, Line (5), Column (4).

[c] Per Schedule 7, Table A, Line (5), Column (5).

[d] Consists of overall return of 10.67 percent plus Federal and State income tax component of 4.46 percent. The income tax components are estimated at .398938/.601062 [tax rate/1-tax rate] of the preferred and common equity components.

[e] Per Schedule 7, Table A, Line (5), Column (6).

Central Maine Power Company
Marginal Unit Capacity Cost by Costing Period
Generation and Transmission

		Annual Cost: Secondary Service	Annual Cost: Primary Service	Annual Cost: Sub-Transmission Service	Annual Cost: Transmission Service	Period Assignment Factor [a]	Seasonal Cost: Secondary Service	Seasonal Cost: Primary Service	Seasonal Cost: Sub-Transmission Service	Seasonal Cost: Transmission Service
		-------(1990 Dollars per Kilowatt)------				(Percent)	-------(1990 Dollars per Kilowatt)------			
							(1)x(5)	(2)x(5)	(3)x(5)	(4)x(5)
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Winter Peak Period:										
Generation	[b]	$ 62.03	$ 59.98	$ 58.19	$ 57.02	71.0%	$ 44.04	$ 42.58	$ 41.32	$ 40.48
345kV Transmission	[b]	10.29	9.95	9.65	9.46	88.8%	9.13	8.83	8.57	8.40
115kV Transmission	[c]	40.73	39.38	38.21	37.44	88.8%	36.17	34.97	33.93	33.24
34kV Sub-Transmission	[d]	5.22	5.05	4.90	---	88.8%	4.64	4.48	4.35	0.00
Total Transmission		56.24	54.37	52.76	46.89	---	49.94	48.28	46.85	41.64
Winter Interim Period:										
Generation	[b]	62.03	59.98	58.19	57.02	5.5%	3.41	3.30	3.20	3.14
345kV Transmission	[b]	10.29	9.95	9.65	9.46	5.7%	0.59	0.57	0.55	0.54
115kV Transmission	[c]	40.73	39.38	38.21	37.44	5.7%	2.32	2.24	2.18	2.13
34kV Sub-Transmission	[d]	5.22	5.05	4.90	---	5.7%	0.30	0.29	0.28	0.00
Total Transmission		56.24	54.37	52.76	46.89	---	3.21	3.10	3.01	2.67
Winter Off-Peak Period:										
Generation	[b]	62.03	59.98	58.19	57.02	3.4%	2.11	2.04	1.98	1.94
345kV Transmission	[b]	10.29	9.95	9.65	9.46	3.2%	0.33	0.32	0.31	0.30
115kV Transmission	[c]	40.73	39.38	38.21	37.44	3.2%	1.30	1.26	1.22	1.20
34kV Sub-Transmission	[d]	5.22	5.05	4.90	---	3.2%	0.17	0.16	0.16	0.00
Total Transmission		56.24	54.37	52.76	46.89	---	1.80	1.74	1.69	1.50
Other On Peak Period:										
Generation	[b]	62.03	59.98	58.19	57.02	18.0%	11.17	10.80	10.48	10.26
345kV Transmission	[b]	10.29	9.95	9.65	9.46	2.2%	0.23	0.22	0.21	0.21
115kV Transmission	[c]	40.73	39.38	38.21	37.44	2.2%	0.90	0.87	0.84	0.82
34kV Sub-Transmission	[d]	5.22	5.05	4.90	---	2.2%	0.11	0.11	0.11	0.00
Total Transmission		56.24	54.37	52.76	46.89	---	1.24	1.20	1.16	1.03
Other Interim Period:										
Generation	[b]	62.03	59.98	58.19	57.02	1.0%	0.62	0.60	0.58	0.57
345kV Transmission	[b]	10.29	9.95	9.65	9.46	0.1%	0.01	0.01	0.01	0.01
115kV Transmission	[c]	40.73	39.38	38.21	37.44	0.1%	0.04	0.04	0.04	0.04
34kV Sub-Transmission	[d]	5.22	5.05	4.90	---	0.1%	0.01	0.01	0.00	0.00
Total Transmission		56.24	54.37	52.76	46.89	---	0.06	0.05	0.05	0.05
Other Off-Peak Period:										
Generation	[b]	62.03	59.98	58.19	57.02	1.1%	0.68	0.66	0.64	0.63
345kV Transmission	[b]	10.29	9.95	9.65	9.46	0.1%	0.01	0.01	0.01	0.01
115kV Transmission	[c]	40.73	39.38	38.21	37.44	0.1%	0.04	0.04	0.04	0.04
34kV Sub-Transmission	[d]	5.22	5.05	4.90	---	0.1%	0.01	0.01	0.00	0.00
Total Transmission		56.24	54.37	52.76	46.89	---	0.06	0.05	0.05	0.05

[a] Assignment factors are from Exhibit Maheu-25, Schedule 1, p. 1.
[b] The annualized costs of generation from Schedule 8, Col. (1), and 345-kV transmission from Schedule 8, Col. (2), were adjusted by demand loss factors of 1.10614, 1.06948, 1.03771 and 1.01674 for service from secondary, primary, sub-transmission, and transmission, respectively, per Exhibit Maheu-25, Schedule 17 note [b].
[c] The annualized cost of 115kV transmission from Schedule 8, Col. (3), was adjusted by demand loss factors of 1.10465, 1.06804, 1.03631 and 1.01537. for service from secondary, primary, sub-transmission and transmission, respectively,per Exhibit Maheu-25, schedule 17, note [c].
[d] The subtransmission annualized cost from Schedule 8, Col. (4), was adjusted by demand loss factors of 1.08793, 1.05187 and 1.02062 for service from secondary, primary and subtransmission, respectively, per Exhibit Maheu-25, Schedule 17, note[d].

Central Maine Pc r Company
Marginal Unit Capacity Cost Per CP
Distribution

		Annual Cost			
		Secondary Service	Primary Service	Sub-Transmission Service	Transmission Service
		(1990 Dollars per Kilowatt)			
		(1)	(2)	(3)	(4)
Primary Distribution	[a]	47.39	45.82	---	---
Secondary Distribution	[b]	33.32	---	---	---

[a] The primary distribution annualized cost from Schedule 8, Col (5), was adjusted by demand loss factors of 1.06595 and 1.03062 for service from secondary and primary, respectively, per Exhibit Maheu-25,Schedule 17, note [e].

[b] The secondary distribution annualized cost from Schedule 8, Col. (6), was adjusted by a demand loss factor of 1.03428, per Exhibit Maheu-25, Schedule 17, note [f].

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 2

QUESTION 17:

With regard to Watkins testimony, Page 9, Lines 1-15, is it Mr. Watkins' belief that management should only manage in the long-run?

a. If so, when is the long run ever met?
b. Please provide studies of companies managing in and pricing based on the long run and ignoring short run fixed costs.
c. Does Watkins agree or disagree that the volatility of the current economic environment supports the need for short run goals and pricing rather than long run pricing? Explain your position.
d. Watkins states that prices for competitive products and services in capital intensive industries are established on volumetric bases, including those that were once regulated. Does Watkins believe these so-called past regulated industries, motor transportation, airline travel and rail services, are natural monopolies?
    1) If not, what market structure does he consider them to be?
    2) Is such a market structure a valid comparison to the natural monopoly market structure of Owen?
e. Industries such as cable, internet and phone are considered natural monopolies. Rates charged for these goods are not volumetric rates. Are the prices these industries charge not efficient?

WITNESS RESPONSIBLE:
Glenn Watkins

RESPONSE:

17. No.

a. Please see above.

b. Please see above.

c. Yes. All firms must be able to price at or above short-run variable costs.

d. By virtue of products being "competitive" these industries are not by definition "natural" monopolies.

1) Please see above.

2) In the context used within Mr. Watkins' testimony, yes.

e. By virtue of the competition that exists within these industries, Mr. Watkins disagrees that these industries are considered "natural monopolies." This being said, Mr. Watkins acknowledges that the pricing structure of these industrials are largely fixed in nature. These pricing structures evolved primarily due to the incredibly low marginal cost of minutes of use or data transmitted which resulted from digital equipment.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 18:

With regard to Watkins testimony, Page 9, Lines 17-30, and, Page 10, Lines 1-25 based on economic behavior assumptions, does he believe consumers react to the individual components of their bill or the total bill?

a. If the bill is revenue neutral and if a consumer reacts to the total bill rather than the individual components, how is additional consumption promoted?

b. Please provide support, in the form of studies and other documents, for Watkins' contention that consumers will analyze the components of their electric bill, will recognize a lower energy rate, and, as a result, use more energy .

RESPONSE:

18. Residential consumers react to changes in their total bill.

a. Please see above.

b. Please see above.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 19:

With regard to Watkins testimony, Page 11, Lines 9-19, please provide support that a pricing structure that is largely fixed in nature promotes inefficient utilization of resources.

RESPONSE:

Please see Mr. Watkins' testimony, page 9, line 17 through page 14, line 18.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 20:

With regard to Watkins testimony, Page 11, Lines 21-31, and Page 12, Lines 1-2, please support his contention that with Owen's proposed rate structure the majority of a typical bill will no longer be volumetrically based.

a. In Watkins' testimony, Page 11, Lines 28 and 29, he contends the rationale of fixed charge pricing approaches escapes him as an economist. Please explain the basis for this statement and provide support for same.

b. In Watkins' testimony, Page 11, Lines 29-31 and Page 12, Lines 1 and 2, please state the facts upon which he bases his opinions and/or conclusions that Owen would enjoy excessive profit about normal margins, and how this new rate structure will result in alleged excessive profits.

RESPONSE:

20. Mr. Watkins does not claim that the majority of a typical customer's electric bill will not be volumetrically based. Please see Mr. Watkins testimony, page 11, line 21 through page 12, line 2.

a. Please see Mr. Watkins' testimony, page 11, line 29 through page 12, line 2.

b. Mr. Watkins does not claim that Owen would enjoy excessive profits under its proposed rate structure.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 21:

With regard to Watkins testimony, Page 12, Line 4 through 17, Watkins testified that comparing competition for electric generation with the bundled electric service provided by Owen is not a good apples-to–apples comparison. Please state the facts upon which Watkins reached this conclusion and why Watkins still compares and uses the Texas retail electric competition for support of his position.

a. State in full detail why Watkins did not use Texas Electric Cooperative's rate structure as a comparison.

b. State examples, if any, of what Watkins would determine to be an "apples-to-apples" comparison.

RESPONSE:

21. Mr. Watkins statement relates to those situations in which only power supply (generation and transmission) is subject to competition.

a. Competition is not available to Texas consumers served by cooperatives.

b. Bundled electric service, generally.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 22:

Referring to Watkins testimony, Page 12, Lines 21 through 27; page 13, lines 1 through 32 and page 14, lines 1 and 2, is Watkins:

a. Advocating deregulation? If so, explain in detail, the basis for this position.
b. If he's advocating deregulation, then must a utility still cover its cost to serve if deregulated?
c. In reference to Schedule GAW-2, for the companies listed, please provide the following information: the type of company (marketer, wholesaler, municipal, investor owned utilities, cooperative, etc), services provided (distribution, supplier or both), and density.
d. Please provide the residential customer charges for all Texas electric cooperatives, the average residential customer charge, the average residential energy charge, together with the customers per mile of line for each such cooperative or utility.

RESPONSE:

a. No.

b. Please see above.

c. The companies listed in Schedule GAW-2 are marketers. These marketers provide service from the generator to the consumer's meter. "Density" is unknown.

d. Unknown.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 23:

Referring to Watkins testimony, Page 14, Line 4 through 18:

a. Provide studies supporting the notion that consumers and the market have a clear preference for volumetric pricing.
   1) Is this notion applicable to natural monopolies? If so, provide support.
b. As it references the statement, "The only reason utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status" on lines 12-14,
   1) Is Watkins implying that natural monopolies can price at will and that Owen follows such a premise? And, if so, the basis for that supposition?
   2) Is Watkins implying that all natural monopolies base more than ninety percent of their pricing on volume in today's market? And, if so, give specific examples of such natural monopolies.

RESPONSE:

a. With all due respect, this is common knowledge.

   1) "Natural monopolies" are generally regulated. As such, these pricing structures are established through regulatory processes.

b. 1) No.

   2) No.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 24:

Referring to Watkins testimony, Page 14, Line 20 through 31 and Page 15, Lines 1 through 20:

a. Does Watkins support surcharges to pay for conservation programs? If, the answer is 'yes', then provide a detailed explanation to support the answer with specific examples. If the answer is 'no', then explain why Watkins does not support surcharges to pay for conservation programs.
b. Does Watkins believe that aggressively initiating and promoting cost effective conservation programs supports his position of volumetric rates? If so, how?
c. How does Watkins explain his position on advocating conservation but continuing volumetric rates because the industry has "grown and prospered" and will "continue(s) to do so"?
d. In Watkins' opinion, how does the new rate design deter Owen from promoting all effective energy conservation measures?

RESPONSE:

a. Unless mandated or otherwise required, generally, no.

b. Yes. Please see Mr. Watkins' testimony, page 14 line 20 through page 15, line 20.

c. Please see above.

d. Mr. Watkins does not claim that Owen's proposed rate design will "deter" it from promoting energy conservation measures.

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 25:

Referring to Watkins testimony, Page 15, Line 22 through 31; Page 16, Lines 1 through 12:

a. Does Watkins support a fully allocated cost of service study as a means of determining the cost of service to the rate classes? If yes, why? If no, why not?
b. Why does Watkins believe that overhead expenses or any other indirect costs are more appropriately recovered through energy charges?
c. Does Watkins feel it is fair for the customer to pay the overhead expenses of the utility for using an extra light instead of just the energy charge for turning on an extra light in their home? Please defend the position taken.

RESPONSE:

a. Objection, relevance. The question as posed exceeds the scope of Mr. Watkins' testimony and the issues presented in the instant case. Without waiving this objection, Mr. Watkins did not address this issue.

b. Please see Mr. Watkins' testimony, page 16, lines 14 through 20.

c. Mr. Watkins is of the opinion that it is fair for customers to pay for <u>all</u> electricity consumed.

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 2

QUESTION 26:

Referring to Watkins testimony, Page 15, Lines 25 through 30:

a. Provide authoritative support for Watkins' "direct customer cost analysis technique."
b. Provide copies of the case orders where this technique has been accepted by regulatory authorities.

RESPONSE:

a. Please see the attached excerpt from the NARUC Electric Utility Cost Allocation Manual (Chapter 7) (As Attachment 1).

   Please also refer to the following excerpt from the Bonbright treatise "Principles of Public Utility Rates":

   > Customer costs are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of the drop wire, metering and billing, along with whatever other nonrecoverable expenses the company must incur in taking on another consumer. In more general terms, they are the minimum service, metering, accounting, etc. costs of connecting another customer or the savings in costs of not connecting the customer. [Page 490]

   See Attachment 2.

b. Mr. Watkins does not maintain Commission Orders or Decisions. However, the direct customer cost analysis conducted by Mr. Watkins is widely used throughout the United States in evaluating the reasonableness of customer charges. Mr. Watkins is aware of Commission

WITNESS RESPONSIBLE:
Glenn Watkins

reliance on this method in at least Arizona, New Jersey, Pennsylvania, South Carolina, Idaho, and Washington State.

Attached please find a legal brief from a just completed Columbia Gas of Pennsylvania rate case in which Mr. Watkins happened to have been involved that provides citations to the Pennsylvania Public Utilities Commission's reliance on direct customer costs (as Attachment 3). Mr. Watkins is not an attorney, and was not the author of that brief.

WATKIN'S RESPONSE TO OWEN QUESTION 26

ATTACHMENT 1

ELECTRIC UTILITY
COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue, NW
Washington, D.C. 20005
USA
Tel. (202) 898-2200
Fax (202) 898-2213
www.naruc.org

CHAPTER 7

CLASSIFICATION AND ALLOCATION OF CUSTOMER-RELATED COSTS

Customer-related costs (Accounts 901-917) include the costs of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by any particular function of the utility's operation or by particular classes of their customers. An exception would be Account 904, Uncollectible Accounts. Many utilities monitor the uncollectible account levels by tariff schedule. Therefore, it may be appropriate to directly assign uncollectible accounts expense to specific customer classes.

I. FUNCTIONALIZATION

The usual approach in functionalizing customer accounts, customer service and the expense of information and sales is to assign these expenses to the distribution function and classify them as customer-related.

A less common approach is called the plant/labor method that functionalizes customer accounts, customer service, and sales expenses according to the previously determined functionalization of utility plant and labor costs. The amount of payroll costs included in generation-, transmission-, and distribution-related operation and maintenance expenses determine the labor component of this functionalization. Since the majority of a utility's labor costs tend to be in distribution, the plant/labor method will tend to emphasize the distribution functionalization of customer accounts, customer service, and sales expenses.

II. CLASSIFICATION AND ALLOCATION

When these expenses are functionalized by the plant/labor method, they will follow the previously determined classification and allocation of generation, transmission, and distribution facilities.

Where these accounts have been assigned to the distribution function and classified as customer-related, care must be taken in developing the proper allocators. Even with detailed records, cost directly assigned to the various customer classes may be very cumbersome and time consuming. Therefore, an allocation factor based upon the number of customers or the number of meters may be appropriate if weighting factors are applied to reflect differences in the cost of reading residential, commercial, and industrial meters.

A. Customer Account Expenses (Accounts 901 - 905)

These accounts are generally classified as customer-related. The exception may be Account 904, Uncollectible Accounts, which may be directly assigned to customer classes. Some analysts prefer to regard uncollectible accounts as a general cost of performing business by the utility, and would classify and allocate these costs based upon an overall allocation scheme, such as class revenue responsibility.

B. Customer Service and Informational Expenses (Accounts 906 - 910)

These accounts include the costs of encouraging safe and efficient use of the utility's service. Except for conservation and load management, these costs are classified as customer-related. Emphasis is placed upon the costs of responding to customer inquiries and preparing billing inserts.

Conservation and load management costs should be separately analyzed. These programs should be classified according to program goals. For example, a load management program for cycling air conditioning load is designed to save generation during peak hours. This program could be classified as generation-related and allocated on the basis of peak demand. The goal of other conservation programs may be to save electricity on an annual basis. These costs could be classified as generation-related and allocated on the basis of energy-usage allocation. However, if conservation costs are received through cost recovery similar to a fuel-cost recovery clause, allocating the costs between demand and energy may be too cumbersome. In such cases, the costs could be received through an energy clause. A demand-saving load management program actually saves marginal fuel costs, and therefore energy.

C. Sales Expenses (Accounts 911 - 917)

These accounts include the costs of exhibitions, displays, and advertising designed to promote utility service. These costs could be classified as customer-related, since the goal of demonstrations and advertising is to influence customers. Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers. Although these costs are incurred to influence the usage decisions of customers, they cannot properly be said to vary with the number of customers. These costs should be either directly assigned to each customer class when data are available, or allocated based upon the overall revenue responsibility of each class.

WATKIN'S RESPONSE TO OWEN
QUESTION 26
ATTACHMENT 2

Principles of Public Utility Rates

Second Edition

by
JAMES C. BONBRIGHT
ALBERT L. DANIELSEN
DAVID R. KAMERSCHEN

with assistance of
JOHN B. LEGLER

Public Utilities Reports, Inc.
Arlington, Virginia

companies also allow for voltage differences and for distances between points of generation and consumption as well as for other clearly assignable cost elements. Other cost breakdowns — such as those allowing for the power factor and the customer-density factor — have been used to a limited extent. If the aforementioned threefold division of costs were to have its counterpart in the actual rates of charge for service, as it actually does have in some rates, there would result a three-part rate for any one class of service. For example, the monthly bill of a residential consumer might be the sum of a \$5 customer charge, an \$80 charge for 800 kilowatt-hours of energy at 10 cents per kilowatt-hour, and a \$50 charge for a maximum demand of 10 kilowatts' during the month at the rate of \$5 per kilowatt — a total bill of \$135 for that month. But our present interest lies in the measurement of costs of service, and only indirectly in rates that may or may not be designed to cover these costs. Let us therefore consider each of the three types of cost in turn, recognizing that this simplified classification is used only for illustrative purposes; costs actually vary in much more complex ways.

Customer Costs

Customer costs are those operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption. Included as a minimum are the costs of the drop wire, metering and billing, along with whatever other nonrecoverable expenses the company must incur in taking on another consumer. In more general terms, they are the minimum service, metering, accounting, etc. costs of connecting another customer or the savings in costs of not connecting the customer. These minimum costs are substantially higher for large industrial users, who require more costly connections and metering devices than for residential and small commercial customers. While costs on this order are sometimes separately charged for in residential and commercial rates, in the form of a mere "service charge," they have been historically more frequently wholly or partly covered by a minimum charge which entitled the consumer to a very small amount of gas or electricity with no further payment.

Since PURPA in 1978, many electric companies have replaced the minimum monthly charge with a customer charge. This fixed charge is designed to cover the costs directly attributable to serving the customer class. However, there are those who argue that it represents an extreme version of declining block rates with the first unit of consumption bearing the entire burden of the fixed charge. Since PURPA prohibited declining block tariffs unless there were falling energy costs — which was not likely since the standard operating procedure is to bring the lowest cost generating units on line first — this has been interpreted as representing an end run. These critics also argue that a customer charge may reduce social welfare, as the fixed customer charge amounts to a regressive head tax (see Renshaw and Renshaw, 1979). This is of course entirely beside the point from a cost allocation perspective.

The *FERC Handbook* (1983, p. 52) recognizes that while there are no hard-and-fast rules for allocating customer costs, as they depend on the type of costs involved, the issue is not usually litigated as the dollars involved are usually not substantial. The really controversial aspect of customer-cost imputation arises because of the cost analyst's frequent practice of including, not just those costs that can be definitely earmarked as incurred for the benefit of specific customers, but also a substantial fraction of the annual maintenance and capital costs of the secondary (low-voltage) distribution system — a fraction equal to the estimated annual costs of a hypothetical system of minimum capacity. This minimum capacity is sometimes determined by the smallest sizes of conductors deemed adequate to maintain voltage while keeping them from falling of their own weight. In any case, the annual costs of this phantom, minimum-sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their inclusion among the customer costs is defended on the ground that, since they vary directly with the area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the "zero-intercept" method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system (Sterzinger, 1981).

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.

While, for the reason just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground. For this exclusion of minimum-sized distribution system costs makes more plausible the assumption that the *remaining* cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load.

But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.

In actual practice the vast majority of utilities utilize some form of minimum system to classify costs, which is in line with the FERC accounts. Sterzinger (1981) is critical of this practice and recommends that to avoid the overcollection of charges from low-use residential customers, regulators should classify distribution costs as demand costs. Neither of these procedures can be justified as a cost allocation in the sense of directly assignable costs, for they are in fact nonassignable.

Allocation, in whole or in part, would be at least theoretically possible if a customer-density parameter were added to the three traditional cost components. But if this factor were embodied, not only in cost analysis but in the resulting rate differentials, rates would not be uniform throughout a given community and hence would violate a generally accepted tradition (see Watkins, 1921, p. 212 and Havlik, 1938, Chapter 8 and Appendix A).

Energy or Unit-related Costs

The energy or unit-related costs components of this threefold division of total annual costs is supposed to consist of those costs which would vary with changes in the unit consumption of energy, measured in kilowatt-hours, even if the number of customers should

WATKIN'S RESPONSE TO OWEN QUESTION 26

ATTACHMENT 3

COMMONWEALTH OF PENNSYLVANIA

OFFICE OF CONSUMER ADVOCATE
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Harrisburg, Pennsylvania 17101-1923
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Consumer Advocate

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June 27, 2011

Rosemary Chiavetta
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

RE: Pennsylvania Public Utility Commission
v.
Columbia Gas of Pennsylvania, Inc.
Docket Nos. R-2010-2215623;
R-2010-2201974

Secretary Chiavetta:

Enclosed for filing please find the Office of Consumer Advocate's Main Brief in the above referenced proceeding.

Copies have been served as shown on the Certificate of Service.

Respectfully Submitted,

Candis A. Tunilo

Candis A. Tunilo
Assistant Consumer Advocate
PA Attorney I.D. # 89891

Enclosures
cc: Hon. Katrina L. Dunderdale/ALJ
Certificate of Service
*138872

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket Nos. R-2010-2215623;
	:	R-2010-2201974
	:	
Columbia Gas of Pennsylvania, Inc.	:	

MAIN BRIEF
OF THE OFFICE OF CONSUMER ADVOCATE

Tanya J. McCloskey
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DATED: June 27, 2011

TABLE OF CONTENTS

TABLE OF CITATIONS

Cases

Statutes

Regulations

Administrative Decisions

Appendices

I. INTRODUCTION

The Office of Consumer Advocate (OCA) hereby submits this Main Brief regarding the base rate increase proposed by Columbia Gas of Pennsylvania, Inc. The parties settled all issues in the base rate case filed by Columbia Gas of Pennsylvania, Inc. (Columbia or Company) except: (1) residential rate design and (2) the objection to Columbia's existing CAP-Plus program raised by Pennsylvania Communities Organizing for Change, Inc. d/b/a ACTION United, Nettie Pelton and Carol Collington (collectively PCOC). The OCA submits that the Pennsylvania Public Utility Commission (Commission) should reject the Company's proposed residential rate design change to a "levelized distribution charge." Instead, the Commission should direct Columbia to continue with its current residential rate design, which includes a customer charge and volumetric charge. Additionally, the OCA submits that the Commission should reject PCOC's challenge to Columbia's existing CAP-Plus program.

A. Background

Columbia provides natural gas service to approximately 411,000 residential, commercial, industrial, resale and transportation customers in 26 counties in western, northwestern, central and southern Pennsylvania.

On September 29, 2010, the Company filed Supplement No. 156 to Tariff Gas – Pa. P.U.C. No. 9 (BTU Supplement No. 156) with the Pennsylvania Public Utility Commission (Commission or PUC) at Docket No. R-2010-2201974 to become effective November 27, 2010. In the BTU Supplement filing, Columbia requested approval of a modification to Tariff Rule No. 15 to provide for a BTU content adjustment to the monthly determination of customers' billing MCFs in addition to existing adjustments for pressure and temperature.

By Order dated November 19, 2010, the Commission suspended the BTU Supplement filing until May 27, 2011. On December 3, 2010, Columbia filed Supplement No. 160 to Tariff Gas – Pa. P.U.C. No. 9 (BTU Supplement No. 160) noting the effective date of May 27, 2011.

On January 14, 2011, Columbia filed Supplement No. 163 to Tariff Gas - Pa. P.U.C. No. 9 (Supplement No. 163) with the Commission at Docket No. R-2010-2215623 to become effective on March 15, 2011.[1] In its filing, Columbia requested that the Commission approve rates and rate changes, which would increase the rates for residential and commercial customers, while lowering rates for industrial customers. The proposed rates reflected an increase in overall annual revenues of $37.8 million, or approximately 7.7% over the Company's annual revenues at present rates.

By Order entered March 17, 2011, the Commission suspended the implementation of Supplement No. 163 until October 18, 2011, and instituted an investigation into the lawfulness, justness and reasonableness of the rates, rules and regulations proposed in Supplement No. 163. Thereafter, the Company filed Supplement No. 165 to Tariff Gas Pa. P.U.C. No. 9 (Supplement No. 165) pursuant to the Commission's March 17, 2011, Order.

Upon the unopposed motion of Columbia,[2] the BTU filing at Docket No. R-2010-2201974 was consolidated with the base rate filing at Docket No. R-2010-2215623. On January 21, 2011, the matters were assigned to Administrative Law Judge Katrina L. Dunderdale (ALJ).

Columbia last filed for a base rate increase on January 28, 2010, at Docket No. R-2009-2149262, wherein the Company sought an additional $32.3 million in annual gas distribution

[1] At the request of Commission staff, the Company agreed to extend the suspension date for Supplement No. 163 to March 18, 2011.

[2] Columbia agreed to extend the effective date of BTU Supplement 160 to coincide with the effective date of the base rate filing.

revenues. The parties settled the matter, and on or about October 1, 2010, Columbia implemented rates designed to collect $12.7 million in additional annual revenues.

B. Procedural History

On February 3, 2011, the Office of Small Business Advocate (OSBA) filed a Formal Complaint, Public Statement and Notice of Appearance. On February 9, 2011, the OCA filed a Formal Complaint, Public Statement and Notice of Appearance. On February 15, 2011, Dominion Retail, Inc., Interstate Gas Supply and Shipley Energy Company (NGSs) filed a Joint Petition to Intervene. On February 18, 2011, the Columbia Industrial Intervenors (CII) filed a Formal Complaint. On March 4, 2011, The Pennsylvania State University (PSU) filed a Formal Complaint. On March 17, 2011, the Office of Trial Staff (OTS) filed a Notice of Appearance. On March 22, 2011, PCOC filed a Formal Complaint and Entry of Appearance. The following individuals filed Formal Complaints: James M. Landis; Marie A. Weaver; Margaret M. Sentz; Albert E. Jochen; and Patsy Orlando and Maureen A. Doerr Roman. Rate protests were filed by various individuals.

On March 23, 2011, the ALJ convened a prehearing conference, whereupon, *inter alia*, a litigation schedule was adopted. Also, the NGSs' Petition to Intervene was granted. On May 16, 2011, a public input hearing was convened at the Allegheny County Courthouse. Timothy Carryer, President and Chief Executive Officer of Green Over Green, testified at the public input hearing on behalf of Keystone Energy Efficiency Alliance and in opposition to the Company's proposed change to a levelized distribution charge in the rate design for the residential class. Also, on May 16, 2011, a public input hearing was convened in Beaver Falls. No testimony was taken at this hearing.

The OCA submitted five pieces of Direct Testimony on April 25, 2011, three pieces of Rebuttal Testimony on May 20, 2011, and five pieces of Surrebuttal Testimony on June 1, 2011. The OCA also submitted one piece of Supplemental Rebuttal on June 10, 2011. Hearings were convened on June 10, 2011, and all of these testimonies were admitted into the record at that time. By Interim Order dated June 10, 2011, the OCA's Direct Testimony submitted in the BTU proceeding was admitted into the record in this proceeding.

The parties reached a settlement on all issues raised in this proceeding except the Company's proposal to implement a levelized distribution charge for Residential rates and PCOC's proposal to end the CAP-Plus program. The parties will be submitting a Petition for Partial Settlement with accompanying Statements in Support of Partial Settlement.

C. Burden of Proof

1. Rate Design

Columbia bears the burden of proof to establish the justness and reasonableness of every element of its requested rate increase. As set forth in Section 315(a) of the Public Utility Code:

> Reasonableness of rates – In any proceeding upon the motion of the Commission, involving any proposed or existing rate of any public utility, or in any proceedings upon the complaint involving any proposed increase in rates, the burden of proof to show that the rate involved is just and reasonable shall be upon the public utility.

66 Pa. C.S. § 315(a). The Commonwealth Court interprets this principle as follows:

> Section 315(a) of the Public Utility Code, 66 Pa. C.S. § 315(a), places the burden of proving the justness and reasonableness of a proposed rate hike squarely on the utility. It is well-established that the evidence adduced by a utility to meet this burden must be substantial.

Lower Frederick Twp. v. Pa. P.U.C., 48 Pa. Commw. 222, 226-27, 409 A.2d 505, 507 (1980) (emphasis added) (citations omitted). See also Brockway Glass v. Pa. P.U.C., 63 Pa. Commw. 238, 437 A.2d 1067 (1981).

The Pennsylvania Supreme Court has stated that the party with the burden of proof has a formidable task to show that the Commission may lawfully adopt its position. Even where a party has established a prima facie case, the party with the burden must establish that "the elements of that cause of action are proven with substantial evidence which enables the party asserting the cause of action to prevail, precluding all reasonable inferences to the contrary." Burleson v. Pa. P.U.C., 461 A.2d 1234, 1236 (Pa. 1983). Thus, a utility has an affirmative burden to establish the justness and reasonableness of every component of its rate request.

The OCA points out that Pennsylvania law is clear that there is no similar burden for a party proposing an adjustment to a utility base rate filing. See, e.g., Berner v. Pa. P.U.C., 382 Pa. 622, 116 A.2d 738 (1955). In Berner, the Pennsylvania Supreme Court stated:

> [T]he appellants did not have the burden of proving that the plant additions were improper, unnecessary or too costly; on the contrary, that burden is, by statute, on the utility to demonstrate the reasonable necessity and cost of the installations and that is the burden which the utility patently failed to carry.

Berner, 382 Pa. at 631, 116 A.2d at 744. The Commission recognizes this standard in its rate determinations. Pa. P.U.C. v. Equitable Gas Co., 57 PaPUC 423, 471 (1983). See also University of Pennsylvania v. Pa. P.U.C., 86 Pa. Commw. 410, 485 A.2d 1217 (1984); Pa. P.U.C. v. PPL Elec. Util. Corp., 237 PUR4th 419 (PaPUC 2004). Thus, it is unnecessary for the OCA to prove that Columbia's proposed rates are unjust, unreasonable, or not in the public interest. To prevail in its challenge, Pennsylvania law requires only that the OCA show how Columbia failed to meet its burden of proof.

In conclusion, Columbia must affirmatively demonstrate the reasonableness of every element of its claims and demonstrate that its proposed rates are just, reasonable, and in the public interest. The OCA will show that Columbia has failed to satisfy its statutory burden with regard to its proposed changes to the residential rate design, and therefore, the Company's proposal must be rejected.

2. CAP-Plus

Because PCOC is the party proposing a change that Columbia did not include in its filing that will increase the requested rate relief, PCOC has the burden of proving its proposal is just and reasonable and in the public interest. See e.g. Pa. P.U.C. v. Metropolitan Edison Co., 2007 Pa. PUC LEXIS 5, *187 (Met-Ed 2007). When a party in a rate case proposes a new program that will place new costs upon the Company, for which the Company has not requested recovery in its case-in-chief, it is the party making the proposal that bears the burden of proving that the new costs are just and reasonable by a preponderance of the evidence. Id.

In Met-Ed 2007, PennFuture proposed that the companies implement a variety of renewable energy initiatives, which the companies opposed because there was no proposal addressing the recovery of costs associated with the initiatives. Met-Ed 2007 at *183-84. In their Recommended Decision (R.D.), Administrative Law Judges Wayne L. Weismandel and David A. Salapa (ALJs) noted that even in light of Section 315(a), the burden of proof is on PennFuture as to its proposals to have the companies incur expenses not included in the companies' filings. Id. at *184. Specifically, the ALJs stated:

> The provisions of 66 Pa.C.S. §315(a) cannot reasonably be read to place the burden of proof on the utility with respect to an issue the utility did not include in its general rate case filing and which, frequently, the utility would oppose. Inasmuch as the Legislature is not presumed to intend an absurd result in interpretation of its enactments, the burden of proof must be on a party to a general

> rate increase case who proposes a rate increase beyond that sought by the utility.

Pa. P.U.C. v. Metropolitan Edison Co., Docket No. R-00061366, R.D., 79-80 (Oct. 31, 2006) (citations omitted).[3]

In this case, PCOC proposes that the Company replace its exiting, Commission-approved CAP-Plus program with a CAP program that does not charge a "plus" amount to CAP customers but instead flows through any increased CAP costs to non-CAP residential customers via the universal services program (USP) rider. PCOC's proposal would result in Columbia incurring administrative costs to change the CAP program design and implement such changes, and it would increase the cost of the CAP program recovered through the USP rider. The administrative costs would be recovered in base rates, and no provision has been made by Columbia for such recovery in its case-in-chief. The increased costs flowed through the USP rider are also not contemplated in Columbia's requested rate relief. Furthermore, as described below, Columbia opposes PCOC's proposal as not in the public interest. Consequently, the burden of proof is on PCOC to prove that its CAP proposal is just and reasonable and in the public interest by a preponderance of the evidence.

[3] A copy of all unpublished orders and decisions is provided in Appendix B, hereto. If the order or decision is more than 30 pages, only the relevant excerpt is attached and a full copy will be provided to any party upon request.

II. SUMMARY OF ARGUMENT

Columbia proposes to replace the existing Residential rate design, where customers are charged a fixed monthly charge of $12.25 and a volumetric-based charge for all gas consumed, and recover all Residential base rate revenue through a high, fixed monthly charge of $36.88. The OCA opposes this rate design because it unnecessarily and improperly shifts risk from the utility to Residential customers without any reciprocal benefits to the customers. The proposed "Levelized Distribution Charge" would reduce customers' incentive to conserve and disproportionately impact the Company's low volume and low-income users. Moreover, the proposal is inconsistent with economic price theory and this Commission's clear direction that fixed customer charges should reflect only the direct costs of hooking up and maintaining a customer's account. The OCA also opposes the OTS proposal to move gradually toward higher customer charges, through creation of a minimum allowance. Instead, the OCA submits that the existing $12.25 fixed customer charge be maintained, because it is supported by the traditional customer cost studies conducted in this case by the OCA and OTS and that remaining Residential Distribution revenues be recovered through a volumetric usage charge – as Columbia proposes for all other customer classes.

PCOC proposes that Columbia abandon its existing Commission-approved CAP-Plus program and pass on any additional CAP costs resulting from a new DPW directive to non-CAP residential customers. The new DPW directive requires the application of the LIHEAP grant to the CAP customer's asked to pay amount. PCOC asserts that CAP-Plus does not comply with federal law or the Pennsylvania LIHEAP State Plan for 2010-2011. The OCA opposes PCOC's proposal and submits that Columbia's CAP-Plus program does, in fact, comply with federal law and the Pennsylvania LIHEAP State Plan for 2010-2011. Furthermore, the OCA submits that

CAP-Plus complies with this Commission's CAP Policy Statement and standards of affordability. Consequently, PCOC has failed to meet its burden of proving by a preponderance of evidence that its proposal is just, reasonable and in the public interest. Therefore, PCOC's proposal to abandon the CAP-Plus program must be rejected.

III. ARGUMENT

A. Columbia's Proposal to Eliminate Residential Volumetric Distribution Charges and Recover All Revenues Through a Fixed Monthly Customer Charge Should Be Rejected.

1. Introduction

Currently, Columbia's Residential base rates include a fixed monthly customer charge of $12.25 and a volumetric Distribution usage charge for all gas consumed of $2.6891 per MCF. The Company proposes to eliminate its volumetric Distribution usage charge and collect all Residential base rate revenues from a fixed monthly customer charge.[4] At Columbia's filed-for revenue increase for the Residential class, its proposed "levelized distribution charge" is $36.88 per month. CPA St. 12 at 36. The Company does not propose to eliminate volumetric distribution rates for any other class of customers. CPA Exh. 111, Sch. 6; CPA St. 12 at 56.

Columbia advocates this form of Straight Fixed Variable (SFV) rate design as a means to stabilize income, and also argues that this would eliminate the Company's disincentive to support conservation efforts. CPA St. 2 at 18-27; CPA St. 12 at 40-42; OCA St. 5 at 27.

The OCA submits that Columbia's proposed Residential rate design is unreasonable, contrary to sound ratemaking principles, and inconsistent with Commission precedent and direction. Shifting cost recovery to the fixed customer charge reduces customers' ability to control their natural gas energy bill through conservation and disproportionately impacts low volume users. OCA St. 5 at 29, 32-33; OCA St. 3 at 3, 23, 25-26. The Commission has consistently held that fixed customer charges should reflect (only) the direct costs of hooking up and maintaining a customer's account. OCA St. 5 at 34; see, e.g., Pa. P.U.C. v. PPL Gas Util. Corp., 2007 Pa. PUC LEXIS 2; Pa. P.U.C. v. National Fuel Gas Dist. Corp., 83 PaPUC 262, 371

[4] Under Columbia's proposal, the only base rate costs not recovered through the fixed distribution charge are universal service program costs, which are recovered from the Residential class through a volumetric rider. CPA Exh. 14, Sch. 2, Att. 2 at 8, 13, 19.

(1994); Pa. P.U.C. v. West Penn Power Co., 1994 Pa. PUC LEXIS 144, *154; Pa. P.U.C. v. Metropolitan Edison Co., 60 PaPUC 349 (1985); Pa. P.U.C. v. West Penn Power Co., 59 PaPUC 552 (1985).

Using the customer cost analysis methodology that has been approved by the Commission, OCA witness Watkins determined that Columbia's monthly per customer cost is $10.51 to $12.12 per month using the OCA's and Columbia's recommended cost of capital, respectively.[5] OCA St. 5 at 34; Sch. GAW-6. In the interest of rate continuity, however, the OCA recommends maintaining the current rate of $12.25. OCA St. 5 at 34; OCA Exh. GAW-6. Any further increase in the overall Residential revenue responsibility should be collected from the volumetric usage charge.[6] Id.

2. Elimination of Volumetric Charges Reduces Price Signals to Conserve and Is Inconsistent with Long-Standing Commission Precedent.

The OCA agrees that recovering all its base rate costs through a fixed monthly charge could reduce any disincentive that the Company may have to promote conservation; however, the OCA submits that this rate design will have exactly the opposite effect on consumers' incentive to conserve. By increasing the fixed monthly customer charge, and eliminating the base rate MCF usage charge, the effect of SFV rate design is that the customer sees substantially less benefit from his or her own conservation efforts. OCA St. 5 at 32-33.

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[5] Mr. Watkins is a Principal and Senior Economist with Technical Associates, Inc., an economics and financial consulting firm. Mr. Watkins has conducted marginal and embedded cost of service, rate design, cost of capital, revenue requirement, and load forecasting studies involving numerous electric, gas, water/wastewater, and telephone utilities, and has provided expert testimony in Alabama, Arizona, Georgia, Illinois, Kansas, Kentucky, Maine, Maryland, Massachusetts, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Vermont, Virginia, South Carolina, Washington, and West Virginia. A more complete description of Mr. Watkins education and experience is provided in Schedule GAW-1, attached to OCA St. 5.

[6] As noted in Section I.A, *supra*, the Joint Petitioners have reached a proposed Settlement that would increase revenue responsibility for the Residential class by $12.7 million.

OCA witness Watkins explained that the term SFV was coined and adopted by the Federal Energy Regulatory (FERC) in its Order 636, which directed that fixed pipeline costs be recovered through annual fixed demand charges and not through variable usage charges. Id. at 31; Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, FERC Stats. & Regs. (CCH) ¶ 30,939 (1992) (Order 636). Mr. Watkins discussed the two express goals of Order 636, to enhance gas competition at the wellhead by completely unbundling the merchant and transportation functions of pipelines and to encourage the increased consumption of natural gas in the United States. OCA St. 5 at 31 (quoting Order 636 at 8, 128-29). The FERC determined that SFV pricing was the "best method" for increasing gas consumption. Id. (quoting Order 636 at 128-29). The FERC was proved right. Its SFV pricing mechanism greatly reduced the price of incremental (additional) natural gas consumption, thereby significantly increasing the demand for and use of natural gas in the United States subsequent to 1992 (when Order 636 was issued). OCA St. 5 at 32-33.

By way of contrast, if one of the goals in designing retail rates is to promote conservation by Residential customers, then a high fixed monthly customer charge will not accomplish it. As stated by Mr. Watkins:

> As is clearly discussed in the FERC Order, the price signal that results from SFV pricing is meant to promote additional natural gas consumption, not reduce consumption. A rate structure, therefore, that is based entirely on a fixed monthly customer charge sends an even stronger price signal to consumers to use more natural gas. Indeed, a rate structure comprised of fixed monthly customer charges is even more at odds with conservation and efficient pricing than a demand charge based (true SFV such as the one adopted by the FERC) rate structure. Whereas a demand charge rate does recognize relative customer size and allows customers to decide how much service is desired, coupled with the ability to shed revenue responsibility (through capacity

> release), such characteristics are not present or possible with fixed customer charge pricing.

Id. at 32. Mr. Watkins testimony about the effect of high fixed charges on retail conservation incentives was given context by Timothy Carryer, CEO of an energy efficiency company, who testified on behalf of a statewide trade organization (Keystone Energy Alliance) representing 30 businesses and hundreds of energy efficiency and renewable energy professionals. Mr. Carryer stated:

> The [levelized distribution charge] does eliminate the through-put incentive by ensuring that gas companies do not earn more by selling more gas, but it does so in a way that undermines energy efficiency. The high fixed charge of the [levelized distribution charge] weakens any price signal sent to consumers that would link higher consumption to higher prices and lower consumption to savings. Without that clear signal, and obviously this is a signal that I base my entire business proposition on, consumers will continue to use more gas, which in turn leads to more emissions and increased stress on Columbia's distribution system. It will also lengthen the time it takes for consumers to recover the costs of investing in energy efficiency, making business more difficult for my company and hundreds of other contractors, energy auditors engineers and manufacturers involved in energy efficiency.

Tr. 76-77.

Columbia asserts that the budget billing option, which is required by the Commission's regulations, 52 Pa. Code § 56.12(7), "essentially masks the very price signals that parties claim are necessary to encourage conservation." CPA St. 2 at 35. The Company points out that the OCA recommends budget billing in order to help customers avoid higher bills in winter months. Id. at 36. The Company recognizes, however, that the OCA also recommends that customers try to lower their natural gas usage because "[e]very little bit helps." Id. (quoting the OCA's website response to what customers can do about high winter gas bills). The OCA's recommendations go to two points – first, that customers have more control over their bill if more of the utility's revenues are recovered through volumetric charges and, second, that even if customers have volumetric rates for the gas portion of their bill, it still matters that they have volumetric rates for the distribution portion of their bill. OCA St. 5 at 33 (rejecting the notion that the additional cost to consumers is acceptable because it only represents a small portion of their energy bills and/or cost of living). Id.

Further, there is a very real distinction between budget billing and a high, levelized customer charge. A budget bill is still tied to customers' usage. Budget billing does not change the amount charged to customers' accounts during a given month and over the course of twelve months, it only gives them the option to pay the same amount each month. A high, levelized customer charge actually separates the amount charged to customers each month and over the course of twelve months from their usage. CPA Exh. RAF-1. Moreover, because Columbia's budget bill displays the customer's actual usage charges in addition to the budget billing amount, customers still receive a price signal regarding usage. CPA Exh. MRK-3 at 37 (sample budget bill shows "current utility charges" and "actual account status"). To the extent customers do not respond to that price signal during a given month, there remains an annual adjustment where actual charges are reconciled with budget billing amounts to provide an efficiency incentive. CPA St. 12 at 47. The Company acknowledges that these true-ups are higher, *i.e.* provide a stronger price signal, without its proposed SFV rates. Id.

SFV rate design is also contrary to a long line of Commission decisions – and particularly the consistent Statements of Commissioner Cawley – that warn against high fixed customer charges because of their negative impact on customer conservation. As noted by Commissioner Cawley, for example, in an August 27, 2009 Statement regarding the base rate case settlements of UGI Penn Natural and UGI Central Penn Gas Companies: "From a policy perspective, allocating costs to variable distribution charges, instead of allocating them to a fixed customer charge, provides a stronger incentive for customers to conserve." Pa. P.U.C. v. UGI Penn Natural Gas and Pa. P.U.C. v. UGI Central Gas, Docket Nos. R-2008-2079660, R-2008-2079675, Statement of then Chairman Cawley (Aug. 27, 2009); see also Pa. P.U.C. v. PG Energy Div. of So. Union Co., Docket No. R-00061365, Statement of then Vice Chairman Cawley (Nov. 30, 2006) (noting that "the significant reduction in residential customer service charges from those in the case as filed, combined with the reduction or elimination of declining block charges for certain Honesdale customers, should help to provide strong incentives and rewards for energy conservation for these customers"); Pa. P.U.C. v. Duquesne Light Co., Docket No. R-00061346, Statement of then Vice Chairman Cawley (Nov. 30, 2006) (approving provisions that increase incentive for conservation through lower residential service charges and reduced or eliminated declining block charges). See also Pa. P.U.C. v. Citizens Util. Water Co., 86 PaPUC 51, 107-109, 169 PUR4th 552, 603-605 (1996) (the Commission specifically considered that consumers' adjustments in consumption patterns can impact only the volumetric charges, not the customer charge, in denying the Company's proposed increase); Pa. P.U.C. v. Fawn Lake Forest Water Co., 77 PaPUC 153, 175-176 (1992) (higher volume water users received a higher increase than low users).

Several states, including Arizona, Colorado, Delaware, District of Columbia, Florida, Kansas and Wyoming, have rejected movement toward SFV rate design; a number of them have done so because it is inconsistent with conservation. In Arizona, UNS Gas, Inc. proposed to increase its monthly customer charges from $7 to $20 during the summer months and $7 to $11 in winter months, while lowering the commodity rate from $0.3004 per therm to $0.1862 per therm. In rejecting UNS's proposed rate design, the Arizona Corporation Commission stated:

> "[such a] rate design would have the effect of encouraging greater usage of natural gas at a time when, by all accounts, an increase in demand for natural gas is coupled with shortages in supply. We do not believe that it is appropriate to send a signal to customers of 'the more you use, the more you save'"

In the Matter of UNS Gas, Inc., 2007 Ariz. PUC LEXIS 241, *110-11 (Arizona); see also Washington Util. and Transp. Comm'n v. Avista Corp., 279 PUR4th 77, 134 (Wash. 2009) (allowing only a 25¢ increase to the existing $6 customer charge because the proposed increase to $10 would make the variable charge smaller "thereby decreasing the incentive for each customer to conserve on his or her usage"). The Kansas Corporation Commission reached a similar conclusion in considering the issue of throughput incentive for its natural gas utilities:

> Although straight fixed-variable rates are attractive for their relative simplicity and lesser administrative burden, the Commission is concerned about their effect on customer inclination to save energy.

General Investigation into the Commission's Consideration of the Public Utility Regulatory Policy Act's Gas Standards, 2009 Kan. PUC LEXIS 1459, *93-94 (Kansas).

For all of the foregoing reasons, the OCA submits that the Company's proposal to eliminate volumetric rates for recovery of Columbia's Residential revenue requirement would be contrary to the goal of promoting energy conservation and energy efficiency.

3. Creation of a High Customer Charge Would Disproportionately Affect Low Use Customers.

The OCA also opposes Columbia's proposed levelized distribution charge because it would disproportionately impact certain customers within the Residential class. OCA St. 3 at 3, 25-26; OCA St. 5 at 30. Columbia witness Feingold provided a chart showing a comparison of present and proposed monthly bills for Residential customers using 0 to 1500 CCF per month. CPA Exh. 111, Sch. 6 at 1. As shown below, the chart indicates that a "typical" customer using about 15 CCF per month in July, August and September would experience a 69.58% increase for those months under the Company's proposed SFV rate design. Id.; CPA Exh. RAF-1. The same customer would experience a decrease of roughly -8.50% in January, February and March, when usage is closer to 150 CCF. Compare this to the monthly bill impact for a higher and lower use Residential customer:

			DIFFERENCE	
Usage in CCF	Present $	Proposed $	Amount $	Percent %
0	12.25	36.88	24.63	201.06%
3	15.71	39.54	23.83	151.69%
15	29.59	50.18	20.59	69.58%
150	185.68	169.89	(15.79)	-8.50%
350	416.91	347.23	(69.68)	-16.71%
700	821.57	657.59	(163.98)	-19.96%

CPA Exh. 111, Sch. 6 at 1. The percentage increases for low use customers are dramatic, but the Company's chart shows the percentage impact of its proposed rate design on a total bill basis. By calculating the impact on a total bill basis, the Company masks the impact of a $36.88 customer charge on distribution rates. When shown on a distribution basis, the disparate impact on Residential customers with higher and lower usage is even more troubling:

			DIFFERENCE	
Usage in CCF	Present $	Proposed $	Amount $	Percent %
0	12.25	36.88	24.63	201%
3	13.35	37.17	23.28	178%
15	17.76	38.35	20.59	116%
150	67.38	51.60	(15.79)	-23%
350	140.90	71.22	(69.67)	-49%
700	269.54	105.56	(163.98)	-61%

Calculated per CPA Exh. 111, Sch. 6 at 1. Keystone Energy Efficiency Alliance witness Timothy Carryer effectively summarized the problem:

> Under the [levelized distribution charge], a senior citizen on a fixed income and who lives in a small apartment will pay the same distribution charge as a high-usage family living in an 8,000-square foot house. High-usage customers should bear a larger portion of the distribution cost than low-usage customers, but the [levelized distribution charge] tells them all to pay the same amount.

Tr. 75.

Other states, including Arizona, Florida and Wyoming have rejected SFV rate design proposals because of their disproportionate impact on customers. In rejecting the utility's proposal to substantially increase customer charges, the Arizona Corporation Commission stated:

> Although we understand that UNS would like to recover as much of its margin as possible through monthly customer charges, we do not believe it is reasonable to adopt a rate design that would impose a significant increase on customers based on where they live within the Company's service area. Under the Company's recommendation, residential customers with lower usage (i.e., customers typically located in warmer climates) would bear the brunt of the revenue increase due primarily to the dramatic front-loading increase to the fixed monthly customer charge.

Arizona at 110-11. See also Petition by Florida Div. of Chesapeake Util. Corp., 2005 Fla. PUC LEXIS 543, *19-24 (rejecting utility's proposal to move toward a SFV rate structure, in part, because it would result in large increases for customers using less therms than other customers in the same rate class); Petition for Rate Increase by St. Joe Natural Gas Co., Inc., 2008 Fla. PUC LEXIS 448, *33-36 (rejecting shift to SFV rate design because it would unduly penalize small use customers and finding it fairer to set the customer charge at a rate with minimal impact on small customers and allow the utility to recover its other costs via a per therm charge); Application of SourceGas Dist., LLC, 2011 Wyo. PUC LEXIS 124, *71-75 (rejecting the proposed SFV rate design because of the disparate impact of high monthly charges on ratepayers).

Consistent with the reasoning of these other state commissions, the OCA submits that Columbia's proposal to recover 100% of distribution revenues for Residential customers through a fixed customer charge should be rejected because it would disproportionately and unreasonably impact Residential customers with lower gas usage.

4. Creation of a High Customer Charge Would Disproportionately Affect Low-Income Customers.

The Company does not dispute that there is a disproportionate impact on Residential customers who use less natural gas. Mr. Feingold argues, however, that Columbia's low-income customers will benefit from its proposed levelized distribution charge because customers with lower incomes use more natural gas than the Company's average Residential customer. CPA St. 12 at 49-54; CPA Exh. RAF-2. In fact, as demonstrated by OCA witness Roger D. Colton, Mr. Feingold's "zip code study" does not support his conclusions about low-income consumption.[7]

[7] Mr. Colton notes that Mr. Feingold cited several other "studies" that he asserts support his conclusions. OCA St. 3 at 25, n.5. Each of these studies was provided by a utility in a rate case. Mr. Feingold could not, however, provide copies of such studies, could not provide the testimony either supporting or responding to such studies, and had not

OCA St. 3 at 4-15. Likewise, his conclusions are not supported by his use of customers in the Company's energy assistance program as a surrogate for low-income customers as a whole because those programs are targeted toward low-income customers with higher-than-average usage. Id. at 16-20. In contrast, OCA witness Colton, provided reliable evidence that low-income customers in general use less gas than high-income customers. OCA St. 3 at 20-26. Mr. Colton's conclusion is supported by federal and Pennsylvania (statewide and county-specific) data regarding the relationship between housing size, income and energy consumption/expenditures. Id. Each of these matters is addressed below.[8]

a. Zip Code Study

Mr. Colton pointed out four fundamental problems with Mr. Feingold's "zip code study." OCA St. 3 at 4-15. First, the study used 2000 Census data to determine median income for zip codes in Columbia's service territory. CPA St. 12 at 50-51. Then Mr. Feingold sought to determine what relationship, if any, exists between the natural gas consumption within those zip codes and the median income within those zip codes. The problem is that the study does not measure what it purports to measure – Mr. Colton demonstrated that Mr. Feingold's data does not present low-income data. OCA St. 3 at 4-6. Mr. Colton testified:

> Drawing conclusions about the consumption patterns of low-income customers is inappropriate when the data used by Mr. Feingold does not involve low-income customers.
>
> . . .
>
> The median incomes that he uses are well above the Federal Poverty Level, generally reaching well above 300% and 400% of Poverty Level and sometimes reaching more than 500% of Poverty Level. In *no* instance does the median income fall at or near the Federal Poverty Level.

reviewed the data underlying such studies. Id. (citing CPA's responses to OCA-IV-1, OCA-V-36). As such, these studies cannot be considered reliable support for Mr. Feingold's conclusions.

[8] Mr. Colton's background and qualifications are noted in Section III.B., *infra*, and attached to OCA St. 3.

OCA St. 3 at 5-6, 15.

Second, the use of median income does not provide information on the depth of poverty or on the incidence of poverty within a zip code. OCA St. 3 at 6-10. Zip codes with higher median incomes have considerable populations with very low annual incomes, while zip codes with lower median incomes have considerable populations with very high annual incomes. Id. at 8-10. Specifically, Mr. Colton's review showed that:

> ➢ The zip codes with the lowest median incomes contained a considerable number of "high income" households. In seven of the 26 zip codes in the lowest decile range of median income,[9] more than 10% of households lived with annual incomes of more than $75,000 (in 2000). In the second lowest decile, six of the 26 zip codes have more than 10% of their households with annual incomes of $75,000 or more.
>
> ➢ In the zip codes with the highest median income, 19 of the 26 zip codes had more than 10% of their households with annual incomes at or below $20,000; in the next highest decile, 16 of the 26 zip codes had more than 15% of their households with annual incomes at or below $20,000.

Id. at 8-9. Contrary to Mr. Feingold's assertion that a lower median income in a zip code can be used to categorize the income status of the zip code, Mr. Colton showed that the level of aggregate income in a zip code does not typically flow from the level of median income in that zip code. Id. at 9-10; OCA Sch. RDC-1. "[N]o conclusions can be drawn about the income status of a zip code based only on the median income of that zip code." OCA St. 3 at 10.

Third, Mr. Colton identified a timing mismatch between when income data was generated and when consumption data was generated. OCA St. 3 at 11. This is significant because the level of median income is highly variable, particularly at a geographic level as small as a five-digit zip code. OCA St. 3 at 10-13. Mr. Colton's quantitative analysis confirmed this variability. Id. at 11-12. Mr. Colton summarized the problem:

[9] Mr. Colton ranked the zip codes that make up the Columbia Gas service territory (as identified by Columbia Gas) by median income and assigned each zip code to a decile. The "first decile" involves the ten percent lowest income zip codes, while the "tenth decile" involves the ten percent highest income zip codes. OCA St. 3 at 8-9.

> There is a two-year lag between the receipt of household income he relies on and the consumption of natural gas that he relies on. In that two-year period, the relative income of the geographic areas will not only possibly change but will likely change. There are as many "lower-income" geographic areas [Public Use Microdata Areas] that are becoming relatively more wealthy as there are "higher income" geographic areas that are becoming relatively less wealthy. The timing mismatch between Mr. Feingold's income data and consumption data makes it impossible for him to draw the conclusions that he purports to draw from his data.

Id. at 12-13.

Finally, Mr. Feingold based his analysis of the relationship between income and natural gas consumption on a comparison of the income of the users of all fuels with the consumption of natural gas customers. That analysis depends for its legitimacy on the assumption that the median income for all households in a zip code accurately represents the median income of natural gas customers in that same zip code. OCA St. 3 at 13-15. Mr. Colton conducted an empirical analysis of the relationship between the income of natural gas customers and the income for customers using alternative fuels, which showed that -- as a general rule -- the income of natural gas users is higher than the income of users of alternative fuels:

> Out of Pennsylvania's 93 PUMAs, the income of natural gas customers exceeds the income of electric customers by 15% or more in 52 instances. Further, the income of natural gas customers exceeds the income of electric customers by 25% or more in 22 of Pennsylvania's 93 PUMAs.
>
> The same is true for fuel oil, albeit to a lesser degree. Out of Pennsylvania's 93 PUMAs, the income of natural gas customers exceeded the income of fuel oil customers by 15% or more in 30 instances. It exceeded the income of fuel oil customers by 25% or more in eleven (11) instances.

OCA St. 3 at 14.

For each of the reasons discussed by Mr. Colton, Mr. Feingold's "zip code study" cannot support any conclusions about low-income consumption.

b. Reliance on Customers in Assistance Programs

In addition to his flawed "zip code study," Columbia witness Feingold also relied upon the fact that customers in Columbia's energy assistance programs use more gas than the Company's average residential customer for his conclusion regarding the usage of low-income customers. CPA St. 12 at 49-54; CPA Exh. RAF-2. OCA witness Colton explained why it is inappropriate to use LIHEAP, CAP, LIURP and CARES customers as a surrogate for all low-income customers. OCA St. 3 at 16-20. Specifically, LIHEAP serves less than one-third of the Company's total low-income population. Id. at 16. Moreover, LIHEAP customers are likely not to be representative of that low-income population as a whole. If a utility identifies a customer as "low-income" because of the receipt of a LIHEAP grant, that customer is likely to experience higher-than-average usage relative to low-income customers as a whole because the LIHEAP program, by statute, is targeted toward low-income customers with higher than average usage.[10] OCA St. 3 at 17.

Likewise, CAP customers represent a small fraction of all low-income customers (less than one-third). OCA St. 3 at 17. Mr. Colton showed that these customers are not representative of the overall low-income population because the Columbia Gas CAP program operates a percentage of income component:

> If a customer has consumption that is sufficiently low to prevent the customer from having a bill as a percentage of income that is less than the percentage of income targets, the customer will not become a CAP participant.[11] Low-use customers, in other words,

[10] See 42 U.S.C. § 8624(b)(2)(3) ("conduct outreach activities designed to assure that eligible households, especially households with elderly individuals or disabled individuals, or both, and households with high home energy burdens, are made aware of the assistance available under this subchapter. . .") (quoted in OCA St. 3 at 17, n.2).

[11] Mr. Colton explained that, in 2007, he was part of a team that performed a multi-sponsor, multi-state study of low-income assistance programs around the nation and in Pennsylvania. Based on his participation in that study and its findings, he concludes "that a customer that already has low-consumption, and thus a low burden, would not participate in CAP because the CAP objective of reducing natural gas bills by tying those bills to a percentage of income would not be served. For low-use, low-burden customers, rather than experiencing an improvement in their home energy affordability, participation in CAP would instead increase the payments they would be required to

> are screened out of the population. Therefore, to examine the CAP population as a surrogate for all low-income customers would be inappropriate.

Id. at 18 (footnote added).

LIURP is also not an appropriate surrogate for all low-income customers for three reasons. First, it is targeted toward high use customers. OCA St. 3 at 19. In order to be eligible for the program, a customer must have average winter monthly consumption of 180 CCFs or more. Id. (citing CPA's Universal Service Plan at 12). Id. Second, a customer must be a CAP participant. As discussed above, CAP participants will tend to be higher users and not representative of low-income customers as a whole. Id. Finally, it is a prerequisite of receiving LIURP assistance that the customer's home has not been previously weatherized. As summarized by Mr. Colton, "[a]ll three eligibility criteria tend to make LIURP participants non-representative of the low-income population as a whole." OCA St. 3 at 19.

Finally, there is no tie between eligibility for CARES and low-income status; the program is based, primarily, on the customer being a natural gas heating customer exhibiting short-term payment troubles. OCA St. 3 at 19. Moreover CARES is a very small program. Id. Neither characteristic makes the program a reasonable surrogate for the low-income customers as a whole.

The average annual gas usage of the participants in Columbia Gas's universal service programs, thus, is not representative of the usage of all of the Company's low-income customers and does not support any conclusions regarding average low-income usage.

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make. A low-use, low-burden customer would not reasonably choose to participate in such a program." OCA St. 3 at 18.

c. Federal and State Data Shows that Low-Income Customers Generally Live in Smaller Homes and Use Less Natural Gas.

OCA witness Colton showed that, in fact, lower income households generally are low volume users and will be harmed by high customer charges. Mr. Colton reviewed and presented critical data in this regard, which explains that there is a direct relationship between gas usage and income, particularly evidenced by housing size. Based on its analysis of Residential Energy Consumption Survey (RECS) data, the U.S. Department of Energy, Energy Information Administration (DOE/EIA) concluded that as the amount of heated floor space increases, the level of natural gas consumption increases. [12] OCA St. 3 at 22. With the exception of the very largest homes, natural gas consumption is related to the size of the housing unit.[13] Id.; OCA Sch. RDC-2. Low-income households live in homes that are much smaller than higher income households, making it reasonable to conclude that their overall natural gas consumption is lower than the consumption for their higher income counterparts. OCA St. 3 at 22-23; OCA Sch. RDC-3; OCA Sch. RDC-4.

This conclusion is supported by data from the Consumer Expenditures Survey (CEX) compiled by the U.S. Department of Labor's Bureau of Labor Statistics, which shows a direct and unequivocal relationship between expenditures on natural gas and income: as income decreases, natural gas expenditures decrease. OCA St. 3 at 25-26; OCA Sch. RDC-5. As stated by Mr. Colton:

> The relationship between natural gas usage and income appears to be well-established. It is consistent over time; it is consistent over geographic area; it is consistent over household age; it is consistent over household size. Moreover, it is consistent with the factors that the Department of Energy has found to most affect natural gas

[12] OCA witness Colton's review of data for Pennsylvania shows that DOE's conclusion is applicable to Pennsylvania and to Columbia's service territory, specifically. OCA St. 3 at 23.

[13] Obviously, the DOE also uses temperature to determine heating consumption. OCA St. 3 at 21.

> consumption: the size of the housing unit. While low-income households tend to have less efficient housing units, and thus may have higher consumption on a per square foot basis, their housing units are sufficiently smaller that their overall natural gas consumption is lower.

Id. at 26.

In his Rebuttal, Company witness Feingold argued that the RECS data relied upon by Mr. Colton for the conclusion that customers with lower income use less natural gas actually "proves conclusively" his contrary position. CPA St. 112-R at 34. Mr. Colton pointed out, however, that Mr. Feingold looked only at the aggregate number reported for households at or below 100% of Federal Poverty Level. OCA St. 3-S at 2. By failing to consider smaller Poverty ranges, e.g., 0-50%, 51-85%, 76-100%, Mr. Feingold missed seeing that the aggregate amount is disproportionately affected by the higher consumption of households with income at the lowest income level, *i.e.* 0-25% of Poverty. Id. at 3. This is true because RECS uses an annualized income for households whose current income does not reflect their 12-month income. Annualization tends to affect households in the lowest income bracket: "[p]eople who have recently lost their jobs, even though they may have had a middle income for the bulk of the past year; people who have retired, become divorced, become disabled or ill, all would have their income annualized for purposes of income categorization." OCA St. 3-S at 3. Without disaggregating the "less than 100% of Poverty Level" population or considering the micro-data it is difficult or impossible to draw conclusions about the relative consumption of that population. Id.

In further support of his conclusion that low-income households have lower natural gas consumption than non-low-income households, Mr. Colton attached pages of data from the most recent publicly-available RECS study. OCA St. 3-S at 5-6; OCA Sch. RDC-1S. As summarized by Mr. Colton:

> - The data (page 1 of 7) shows that energy consumption on a mmBtu per household basis is considerably higher for housing unit types that are more likely to be occupied by non-low-income households than by low-income households.
>
> - The data (page 2 of 7) shows that energy consumption on a mmBtu per household member basis is considerably higher for housing unit types that are more likely to be occupied by non-low-income households than by low-income households.
>
> - The data (page 3 of 7) shows that these first two conclusions occur *despite* the fact that energy consumption on a thousand Btu per square foot basis is much lower for housing unit types that are more likely to be occupied by non-low-income households than by low-income households.
>
> - The data (page 4 of 7) shows that the primary energy consumption for housing units types on a mmBtu per household basis is considerably higher for housing unit types that are more likely to be occupied by non-low-income households.
>
> - The data (page 5 of 7) shows that the primary energy consumption on a mmBtu per household member basis is considerably higher for housing unit types that are more likely to be occupied by non-low-income households.
>
> - The data (page 6 of 7) shows that these last two conclusions occur *despite* the fact that energy consumption on a thousand Btu per square foot basis is much lower for housing unit types that are more likely to be occupied by non-low-income households.
>
> - Finally, the data (page 7 of 7) shows that the conclusion that low-income households live in smaller housing units is a data-based conclusion, whether the size of the housing unit is measured by the number of square feet of living space or whether it is measured by the number of rooms.

OCA St. 3-S at 5-6.

Next, in challenging Mr. Colton's conclusions, CPA witness Feingold argued that it is not possible to determine the extent of low-income consumption without knowing the relative number of Heating Degree Days (HDDs) in different parts of the Company service territory.

CPA St. 112-R, App. A at A7. He claimed that the difference in HDDs between the highest county in Pennsylvania and the lowest county in Pennsylvania is "68% of the most recent weighted average 30 year HDDs for Columbia." CPA St. 112-R, App. A at A7. When the various low-income populations in Columbia's service territory are associated with variations in HDDs, however, there is not much significance to the variations. See OCA Sch. RDC-2S. Only a small percentage of low-income, CAP and LIHEAP customers live in the highest HDD counties, with most (+90%) low-income customers living in the Pittsburg region and regions where HDDs are closely clustered. OCA St. 3-S at 7-8.

Mr. Feingold also asserted that, instead of relying upon housing unit size as the primary factor in assessing natural gas consumption, other factors must be considered including age and number of household members, appliance stock, dwelling type and other gas appliances. CPA St. 112-R, App. A at A2. In response to discovery, Mr. Feingold was unable to provide any support for his assertions based on data specific or not specific to Columbia. See OCA St. 3-S, Att. A.

The data and analyses that have been provided for the record support Mr. Colton's conclusion that, overall, low-income households tend to live in substantially smaller housing units and, thus, can be expected to have less energy consumption.

d. Conclusion

For the reasons discussed above, Mr. Feingold's testimony cannot serve as the basis for conclusions regarding the relationship between income and natural gas consumption. The testimony and evidence provided by OCA witness Colton show a well-established relationship between natural gas usage and income – that low-income households tend to have smaller housing units, which results in lower overall natural gas consumption and, thus, will be particularly harmed by the Company's proposed rate structure.

5. <u>Recovery of Regulated Utility Costs Through Volumetric Charges Is Consistent with Competitive Markets and Economic Theory.</u>

The economic basis for the OCA's objection to collecting all of Columbia's Distribution costs through a fixed customer charge is provided in the Direct and Surrebuttal testimony of Glenn Watkins. OCA St. 5 at 29-34; OCA St. 5-S at 14-18. Therein, he explained why it is efficient and fair for the Company to recover base rate revenues through volumetric charges.

First, Mr. Watkins addressed the reason we look to the economic theory and actual practice of competitive markets:

> The most basic tenet of competition is that prices determined through a competitive market ensure the most efficient allocation of society's resources. Because public utilities are generally afforded monopoly status under the belief that resources are better utilized without the duplication of the fixed facilities required to serve consumers, a fundamental goal of regulatory policy is that regulation should serve as a surrogate for competition to the greatest extent practical. As such, the pricing policy for a regulated public utility should mirror those of competitive firms to the greatest extent practical.

OCA St. 5 at 29 (citing James C. Bonbright, *et al.*, Principles of Public Utility Rates at 141 (2d. Ed. 1988)).

OCA witness Watkins then explained the structure of pricing in the competitive markets. Mr. Watkins testified:

> Economic theory tells us that efficient price signals result when prices are equal to long-run marginal costs. It is well known that in the long-run all costs are variable and, hence, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity. Indeed, competitive market-based prices are generally structured based on usage, i.e. volume based pricing.

OCA St. 5 at 29. Competitive market-based prices are generally based on usage, *i.e.* volume-based so those who receive more benefits pay more in total than those who receive fewer benefits. Id. at 30. Mr. Watkins explained:

> Marginal cost pricing only relates to efficiency. This pricing does not attempt to always address fairness or equity. From a perspective of fair and equitable pricing of a regulated monopoly's products and services, it is generally agreed that payments for a good or service should be in accordance with the benefits received. In this regard, those that receive more benefits should pay more in total than those who receive fewer benefits.

OCA St. 5 at 30. This philosophy has been, and continues to be the belief of economists, regulators, and the marketplace for many years. Id. at 30, 33; OCA St. 5-S at 18. Virtually every capital intensive industry – agricultural, energy, manufacturing and transportation – is faced with a high percentage of fixed costs in the short-run. Yet prices for competitive products and services in these industries are generally established on a volumetric basis. OCA St. 5 at 30.

The same is true for regulated utilities, which also have a high percentage of short-run fixed costs. Originally (in the late 1800s), utilities charged a fixed fee for service and customers could use as much of the commodity/service as they desired. OCA St. 5 at 30. Recognizing the inefficiency and unfairness of this practice, utilities began metering their services in order to charge customers only for the benefit received. Id.[14] The concept of metering pervades the

[14] A number of early Pennsylvania Public Service Commission decisions reflect the transition from unmetered to metered service and the establishment of volumetric rates. See, e.g., J.W. Cornish v. Fairview Water Co., I PaPSC 19 (1914) (noting water utility proposal to establish metered rates in 1915); Cauffiel v. Citzens' Light, Heat and Power Co., I PaPSC 148 (1914) (finding a $1 minimum charge to be "not more than is reasonably required to meet the expenses necessarily incurred by the utility to place it in a position to be ready to serve); Petition of the York Water Co., I PaPSC 152 (1914) (discussing ordinance by City of York requiring the utility to install and maintain a meter for measuring the quantity of water used and to base its charges or rates therefor). Decisions in other states reflect a similar transition. See e.g., Mayor and City Council of Salisbury v. Salisbury Light, Heat and Power Co., Decisions of the Maryland Public Service Comm'n for the Year 1918, 170 (May 27, 1918) (Commission notes the utility's first metered rate schedule which was made up of a $12 yearly minimum charge and a volumetric charge of 10 cents per kWh); Application of W.S. Mumaw for an Order Giving Authority to Increase Rates, Decisions of the Railroad Comm'n of the State of California, Vol. X, 102 (May 13, 1916) (allowing continuation of flat rates and

Public Utility Code and the Commission's regulations. 66 Pa. C.S. §§ 101, *et seq.*; 52 Pa. Code §§ 1.1, *et seq.* As noted by OCA witness Watkins, with regard to natural gas utilities, specifically:

> the volume of consumption is the most direct, and perhaps best, indicator of benefits received, such that volumetric pricing promotes the fairest pricing mechanism to customers and to the utility.

OCA St. 5 at 30.

Through its proposal to collect all Residential base rate revenues from a fixed monthly customer charge, Columbia is effectively stating that decades of regulation and competitive market pricing are incorrect. The OCA disagrees with this premise and with Columbia's specific arguments that a change in paradigm is warranted.

Company witness Feingold argued that there are businesses in the competitive market that charge fixed rates, like cell phone service providers, cable/satellite TV service providers and movie theaters. CPA St. 112-R at 17. Mr. Watkins agreed that there are exceptions to almost every rule in economics but refuted the examples provided by Mr. Feingold. OCA St. 5-S at 17. Mr. Watkins explained:

> I personally attend movie theaters from time to time and pay based on the frequency in which I attend movies, i.e., each time I attend, I do not pay a fixed monthly fee regardless of the number of movies I attend. With regard to cell phone and cable TV pricing, fixed cost pricing is rational for these industries due to the incredibly low incremental cost of additional minutes of use made possible with digital technology.

Id.

creation of metered rates, noting that some of the utility's customers are metered and remaining customers are expected to be metered).

With regard to the general rule that capital-intensive industries use volume-based pricing, Mr. Feingold argued that the industries mentioned by Mr. Watkins do not provide guidance for regulated pricing because they are not regulated. CPA St. 112-R at 18-19. As discussed above, the goal of regulation is to mirror competitive pricing to the extent possible. OCA St. 5 at 29. The competitive market has determined that volume-based pricing is most efficient. Id. at 30, 33; OCA St. 5-S at 18.

This conclusion is supported by economic theory, which provides that efficient prices are equal to marginal costs. OCA St. 5 at 29-30. Marginal cost is equal to the incremental cost (including capacity and expenses) divided by the incremental output. OCA St. 5-S at 16. Thus, by definition, marginal costs vary with output. Mr. Watkins testified:

> It is well known that in the long-run all costs are variable and, hence, efficient pricing results from the incremental variability of costs even though a firm's short-run cost structure may include a high level of sunk or "fixed" costs or be reflective of excess capacity.

OCA St. 5 at 29.

Mr. Feingold agreed that "[t]he principle of marginal cost pricing provides the prescription for economically efficient prices" but argued that short-run costs instead of long-run marginal costs should be used to set prices. CPA St. 112-R at 16-18. In other words, because most of Columbia's short-run costs are fixed, they should be recovered through fixed charges. Id. Mr. Feingold has not recognized the assumptions underlying the marginal cost model, however, *i.e.* that there is no excess capacity and, as a result, short-run and long-run costs are equal. OCA St. 5-S at 14. In order to set efficient rates, it is necessary to assume these criteria exist. OCA St. 5 at 30, n.10. When there is no excess capacity, short and long run costs are the same. OCA St. 5 at 5-S at 14-15. As discussed, marginal costs are variable. The only fixed component of marginal costs is the small, incremental cost of adding a new customer. As stated by Mr. Watkins:

> [E]very application of marginal cost pricing for utilities (whether using short-run or long-run concept of marginal costs) is based upon the assumption that there is no significant excess capacity present such that additional (incremental) capacity is required to meet additional (incremental) output. The marginal cost, is therefore, equal to the incremental cost (including capacity and expenses) divided by the incremental output. In <u>all</u> cases, a utility's total marginal cost includes a demand marginal cost, an energy (commodity) marginal cost, and a relatively small customer marginal cost. The latter (marginal customer costs) tend to be fairly small as they only include the incremental cost of connecting a new customer.

OCA St. 5-S at 16. Essentially, these marginal customer costs are the "direct" customer costs traditionally approved by the Commission for recovery through fixed customer charges. <u>See</u> OCA St. 5 at 34 (the utility's investment in services and meters and the operating expenses associated with meter reading, customer service, accounting and customer records and collections); OCA Sch. GAW-6; Section III.7, *infra*.

As a final point, it is important to consider that in competitive markets, consumers have the ability to choose their service provider. Thus, the only reason that utilities are able to achieve pricing structures with high fixed monthly charges is due to their monopoly status. OCA St. 5 at 33. Mr. Watkins explained that this is fundamentally unfair:

> [C]ompetitive markets and consumers in the U.S. have demanded volumetric based prices for generations: a regulated utility's pricing structure should not be allowed to counter the collective wisdom of markets and consumers simply because of its market power.

OCA St. 5 at 33-34. For the regulated distribution charges at issue here, Columbia is the monopoly provider. The goal should be to establish pricing that is efficient and fair and serves as a surrogate for competitive pricing to the greatest extent practical.

6. The Evidence Regarding Columbia's Earnings Does Not Support a Departure From Precedent.

As discussed in the preceding sections, volumetric pricing has been the preferred pricing mechanism of this Commission, other regulators, economists and the competitive markets for generations. Columbia provided data showing that Residential usage has declined since the 1990's due to increased appliance efficiency and more efficient construction standards. CPA St. 4 at 10. As a result of this decline in usage, coupled with the impact of higher BTU content from Marcellus Shale Gas, Columbia argued that it does not have a reasonable opportunity to earn its approved rate of return unless it recovers all of its base rate Distribution costs through a fixed charge. Id. at 12-14; CPA St. 1 at 7; CPA St. 2 at 34; CPA Exh. MRK-3 at 1; CPA St. 12 at 37-38.

First, the issue of potential earnings erosion due to higher than average BTU content resulting from Marcellus Shale gas is addressed by the proposed Settlement, which provides that Columbia will bill in dekatherms (a reflection of BTU content) rather than MCF going-forward. This eliminates any concern regarding the effect of BTU content on earnings, as customers will be billed for the heat content of gas delivered to their service area. This change also eliminates the need for a separate BTU-adjustment factor. OCA St. 2 at 10.

Second, although natural gas distribution companies (NGDCs) have faced declining usages per customer due to increased appliance efficiencies and conservation for at least two decades, they continue to achieve earnings at high levels – with revenue generated largely from volumetric-based prices. OCA St. 5 at 28. The Value Line Group of natural gas utility companies has achieved average rates of return on common equity between 11.2% and 12.8% for each year (averaging 12.0%) since 1999. Id. OCA witness Watkins explained:

> These high earnings are largely a result of cost savings from technological advances, economies of scales due to mergers, and customer growth.

Id. The bottom line is that conservation or declining usage is not a new phenomenon and its impact on revenues has been mitigated by other factors.

Columbia argued that the utilities in the Value Line Group may employ full or partial decoupling mechanisms, have different regulatory models or reflect unregulated business activities, thus affecting their earnings. CPA St. 112-R at 15-16. Mr. Watkins acknowledged the likelihood that some of the companies in the Value Line Group engage in riskier business activities. OCA St. 5-S at 17. The fact is, however, that all of the proxy companies used for fair rate of return purposes in this proceeding are included in the Value Line Group. See CPA St. 10 at 4, 13.

CPA witness Moul showed that Columbia's earnings have ranged from 8.9% to 18.9% during the same period, which he asserted is an indication of Columbia's higher risk and need for a stabilizing rate design. CPA St. 110-R at 46. This data shows only that Columbia's return varied more than the "typical" NGDC – it does not show the variability of each NGDC in the group. There is no information to show a correlation between earnings variability and rate design. The data does show, however, that Columbia's average return since 1999, with largely volumetric Residential Distribution rates, is 13.1%, which is higher than the 12.0% average return for the Value Line Group as a whole. Id.

In summary, Columbia's situation is not sufficiently changed or unique to warrant the rejection of existing, efficient and fair pricing mechanisms.

7. Columbia's Customer Cost Analysis Improperly Includes Indirect Costs and Should Be Rejected.

Columbia conducted two customer cost analyses, which indicate that its monthly customer cost per Residential customer is $29.14 to $26.56. Columbia Exh. 111, Sch. 2 at 10, Sch. 3 at 10. Columbia does not recommend using these analyses to develop rates. As discussed in OTS witness Hubert's testimony, the former analysis is based on Design Day and classifies Distribution Mains as partially customer-related and partially demand-related, "with the Demand portion of Mains allocated to classes based on contributions to peak (design) day demand." OTS St. 3 at 37. Both Mr. Hubert and OCA witness Watkins noted in their testimony that this Commission has consistently rejected studies that only reflect peak day demands without consideration of average demands, and has also rejected those studies that allocate a portion of Mains based on customer counts. OTS St. 3 at 37; OCA St. 5 at 5; Pa. P.U.C. v. National Fuel Gas Dist. Corp., 83 PaPUC 262 (1994) (NFGD 1994). The Commission's position is correct because (1) customers connect to the Company's system in order to meet their natural gas needs throughout the year and (2) the Company's Mains are used each day of the year, making annual usage (throughput) a logical basis for cost assignment. See OCA St. 5 at 9 (discussing cost of service studies). Thus, the Company's first customer cost analysis should not be given any weight in the Commission's determination of an appropriate customer charge for Columbia.

Columbia's second customer cost analysis is based on the Peak & Average method. Columbia Exh. 111, Sch. 3 at 10. In making this calculation, however, Company witness Feingold has included costs beyond those direct customer costs that the Commission has found should be included in the determination of the customer charge. OCA St. 5 at 34; OTS St. 3 at 43-45. The Commission has been clear that the customer charge should be designed to recover those costs that are directly associated with the metering and billing of residential customers. Id.

In several base rate cases, the Commission has clearly defined what is included in the basic customer costs for determining the customer charge – (only) those costs which directly relate to the Company's investment in services and meters as well as the operating expenses associated with meter reading, customer service, accounting and customer records and collections. Id.; see Pa. P.U.C. v. Metropolitan Edison Co., 60 PaPUC 349 (1985); Pa. P.U.C. v. West Penn Power Co., 59 PaPUC 552 (1985); Pa. P.U.C. v. West Penn Power Co., 1994 Pa. PUC LEXIS 144, *154. In a 1994 National Fuel Gas Distribution Company base rate proceeding, the Commission provided further guidance as follows:

> Commission precedent is clear that indirect customer costs are not properly included in the customer charge. Only those costs which represent items that the utility must have in place each month for each customer are 'basic customer costs" which are properly recovered in the customer charge.

NFGD 1994 at 371.

As OTS witness Hubert explained, the Company's calculation of the Residential customer costs includes far more than the direct costs identified by the Commission:

> As shown on Columbia Exhibit No. 111, Schedule 3, the Company has included operating and maintenance expenses related to distribution, customer accounts expenses, customer service and information expenses, sales expenses, administrative and general expenses, the depreciation expense, net salvage amortized, and return dollars and income taxes on customer-based rate base. Customer service and information expenses are broken down into supervision expenses, customer assistance expenses, informational & instructional expenses, and miscellaneous customer service & information expense as can be seen on OTS Exhibit No. 3, Schedule 20. Sales expenses are also broken down into demonstration expenses, advertising expenses, and miscellaneous expenses. Uncollectible accounts expense and miscellaneous customer accounts expense can be found under the heading of customer accounts expenses.

OTS St. 3 at 43-44.

Moreover, the customer charge indicated by Columbia's Peak & Average customer analysis is well out of line with other customer charges approved by this Commission. A review of the ten current natural gas distribution company tariffs (with gross annual revenues in excess of $40 million) shows a range of $8.55 to $13.25.[15] The Company's calculated customer charge of $26.56 would be nearly 200% higher than the highest customer charge approved for other large NGDCs.

Consistent with the 2006 PPL Gas Utilities Corporation Order, which adopted OCA Witness Watkins' customer cost methodology, Mr. Watkins also performed a Residential customer cost analysis in this case that is based only on direct customer costs, *i.e.*, those costs that vary directly with customer connections. Pa. P.U.C. v. PPL Gas Util. Corp., 2007 Pa. PUC LEXIS 2 (PPL Gas). As discussed above, Mr. Watkins' analysis indicated that the Company's direct customer cost monthly revenue requirement is $10.51 utilizing the OCA's recommended cost of capital (6.88%) and $12.12 utilizing Columbia's proposed cost of capital (8.74%), which is below the current customer charge of $12.25. OCA St. 5 at 34; OCA Exh. GAW-6. The OTS reached similar results following the PPL Gas customer cost analysis: a customer cost of $12.81 using Columbia's proposed cost of capital. OTS St. 3 at 45; OTS Exh. 3, Sch. 19.

In light of these analyses, the OCA recommends maintaining the current customer charge of $12.25. OCA St. 5 at 34; OCA Exh. GAW-6. Further, the OCA recommends that any

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[15] UGI Utilities, Inc. (UGI) has an $8.55 customer charge. UGI Gas Utilities, Inc. Supp. 78 to Tariff Gas – Pa. P.U.C. 5 at 64. A settlement establishing a $9.00 customer charge was approved by the Commission in 1995. Pa. P.U.C. v. UGI Util. Inc. - Gas Division, Docket No. R-00953297, R.D. at 6, 53 (Aug. 17, 1995), adopted by Order (Aug. 31, 1995). Equitable Gas Co., LLC (Equitable) and UGI Penn Natural Gas, Inc. (PNG) have $13.25 customer charges. Pa. P.U.C. v. Equitable Gas Co., LLC, Docket No. R-2008-2029325, R.D. at 7 (Jan. 13, 2009), adopted by Order (Feb. 26, 2009); Equitable Supp. 73 to Tariff Gas – Pa. P.U.C. 22 at 40; PNG Supp. 7 to Tariff Gas – Pa. P.U.C. 8 at 48. When a $1.75 acquisition adjustment credit expires at the end of UGI Central Penn Gas, Inc.'s current base rate case, Docket No. R-2010-2214415, the utility's current $13.10 customer charge will increase by $1.75. Joint Application of UGI Util., Inc. and PPL Gas Util. Corp., Docket No. A-2008-2034045, Order at 11 (Aug. 21, 2008); UGI Central Penn Gas, Inc., Supp. 51 to Tariff Gas - Pa. P.U.C. 3 at 8(e), 17.

increase in the overall Residential revenue responsibility be collected from the volumetric usage charge.[16] Id.

8. OTS's Proposed Minimum Allowance Is Not Consistent with Commission Policy.

OTS witness Hubert persuasively rejected the alleged benefits that Columbia argues will result from SFV rate design. OTS St. 3 at 48-49. He stated:

> The SFV rate design does not consider the fact that due to customers using more gas in the winter, more gas is delivered in the winter and, therefore, because of the nature of the business the Company should recover more of its costs in the winter. As for interclass subsidy, I believe the SFV rate design changes makes the intra-class subsidy worse not better. For example, under the current rate structure a residential customer in a small house that only uses gas for cooking and water heating pays $12.25 per month plus usage. Under the SFV rate design, this same customer would be charged $36.88 per month, and would pay the same monthly charge as a customer that lives in a very large house and uses gas for heating, cooking and water heating. Recovering the same costs from these two residential customers increases intra-class subsidies. The Company provided no guarantee or promise that an SFV rate design will reduce the frequency of rate cases. Many factors besides the average use per customer affect the frequency of rate filings, including new technology, lower operating expense, lower debt costs, lower gas costs (making natural gas more competitive) and the addition of new customers, which would tend to mitigate the need for rate cases.

Mr. Hubert went on to conclude that:

> SFV pricing conflicts with important policy objectives and violates the principle of gradualism. Consumers will have difficulty accepting large up front price increases and low usage customers will feel as though they are being treated unfairly. In the process of removing the Company's disincentive to offer energy efficiency programs, SFV pricing could discourage consumers from making energy efficiency investments because of the low volumetric rates.

[16] As already noted, the proposed Settlement would increase revenue responsibility for the Residential class by $12.7 million. Section I, *supra*.

Id.; see also OTS St. 3-S at 18-23. The OCA is in complete agreement with Mr. Hubert's discussion of the inefficiency and unfairness of SFV rate design. See Sections III.A.3-A.6, *supra*. For the same reasons, however, the OCA does not agree with Mr. Hubert's recommendation to move toward SFV rate design by increasing the Residential customer charge from $12.25 to $19.90, to include a usage allowance of 2 MCF per month.[17] OTS St. 3 at 50-51. The OCA submits that this movement toward SFV pricing is not in the public interest and is at odds with sound economic pricing policy.

As discussed in Section III.A.7, *supra*, the OCA and OTS conducted similar customer cost analyses, which indicated very similar customer charges of $12.12 and $12.81, respectively, utilizing Columbia's proposed cost of capital (8.74%). OCA St. 5 at 34; OTS St. 3 at 45. Based on this analysis, the OCA recommends maintaining the current customer charge of $12.25. Mr. Hubert recommended, instead, that a minimum allowance be added to the customer charge in order to gradually increase the customer charge and provide more guaranteed revenue for Columbia. OTS St. 3 at 50.

The OCA's principal objection to the OTS's proposed minimum allowance is that it results in higher customer charges and is a departure from Commission precedent on the costs to be recovered through customer charges. Having stated that, the OCA submits that creation of a minimum allowance is not consistent with the Commission policy, as evidenced by several Orders. In a 2004 electric case, the Commission rejected a proposal by PPL to create a minimum allowance as follows:

> We agree with the ALJ's disposition of this issue. We believe it is sound regulatory practice to consider the magnitude of an increase

[17] It is the OCA's understanding that, in its Main Brief, the OTS will recalculate the dollar value of the minimum usage amount based on the lesser revenue requirement agreed to in the proposed Settlement, which would produce something less than $19.90. The OCA opposes the creation of any minimum allowance, regardless of its dollar value, so its position is not affected by the update.

> in either the block rates or the customer charge when developing an appropriate rate design and gradualism plays an important role in this design. We found no compelling reason to subsume the first 200 kWh of usage within the customer charge as suggested by PPL and believe that the OCA's recommendation for the customer charge properly reflected the concept of gradualism.

Pa. P.U.C. v. PPL Elec. Util. Corp., 237 PUR4th 419, 461 (PaPUC 2004). In the underlying Recommended Decision, the ALJ agreed that no minimum allowance was warranted, noting the OCA's argument that:

> Under this minimum bill, the customers would get no price signals for the usage of their first 200 kW.

Pa. P.U.C. v. PPL Elec. Util. Corp., 2004 Pa. PUC LEXIS 41, *260.

In a recent water case, the Commission directed the utility to eliminate minimum allowances in its next base rate case because the Company's voluntary, gradual reduction in minimum allowances did not "represent the aggressive commitment to conservation that is needed." Pa. P.U.C. v. Total Envtl. Solutions, Inc. - Treasure Lake Water Div. and Treasure Lake Wastewater Div., 103 PaPUC 110, 160-161 (2008). In that case, OTS agreed that the monthly water allowance should be eliminated so that the customer charge only reflects non-water-related costs such as billing and metering. Id. at 160. The OTS argued further that elimination of the allowance "is consistent with the Commission's concerns regarding water conservation." Id. (citing Pa. P.U.C. v. Emporium Water Co., 95 PaPUC 191, 208 PUR4th 502 (2001) (Emporium) and Pa. P.U.C. v. Lemont Water Co., 81 PaPUC 392 (1994)). In Emporium, the Commission directed the utility to reduce its current water allowances by one-half and to submit a zero-water-allowance customer charge rate design in its next rate case, reasoning that a zero-water-allowance customer charge encourages conservation by billing each customer directly for water use. 95 PaPUC 191 at 213, 208 PUR4th 502 at 524.

Consistent with these decisions and with the Commission's intention to encourage conservation through customer charges that reflect only direct costs, the OCA recommends that the OTS proposal to create a minimum allowance be rejected. Instead, the OCA submits that the current customer charge of $12.25 be continued.

9. Conclusion

For decades, this Commission has stated that fixed monthly customer charges should only include "direct costs." In numerous cases, the Commission has rejected proposals of utilities to increase customer charges on the basis that, in addition to just direct costs, a portion of other Distribution costs should be included in the determination of customer charges. In this case, Columbia goes far beyond those attempts and proposes to recover all Distribution costs through the customer charge. The OCA has established, however, that there is no basis to depart from traditional volumetric ratemaking, which is more economically efficient and fair to all Residential customers.

B. Columbia's CAP-Plus Program Meets the DPW Directive, Complies with Federal Law and the State LIHEAP Plan, Is Just and Reasonable and in the Public Interest.

1. Introduction and Background

Since the late 1980s, Pennsylvania natural gas distribution companies and electric distribution companies have operated Customer Assistance Programs (CAP) that provide low income, payment troubled customers a discounted, affordable bill to help the customer retain utility service. Columbia offers such a program, referred to as the CAP-Plus Program. The affordable portion of the bill that the customer must pay is referred to as the "asked to pay amount." The portion of the bill that the CAP customer does not pay is often referred to as the "CAP credit" or "CAP shortfall" and is charged to other residential customers through the utility's rates, more specifically through the Universal Service Charge (USP) Rider. The CAP customer is not required to pay the total bill for the energy that the customer uses. The CAP customer is only asked to pay a portion of the bill while all other non-participating residential customers bear the cost of the remainder of that customer's bill.

Columbia's CAP is one of the most well-established low income energy assistance programs in Pennsylvania. The Columbia CAP program currently serves over 25,000 customers at a cost to other Columbia residential customers of approximately $30 million per year. In 2009, non-participating residential customers paid, on average, $81 per year in CAP costs to support the program.

This Commission's CAP Policy Statement, and more specifically here, Columbia's CAP Program, has taken care to integrate the federal LIHEAP grants with the CAP to help support these programs and control the cost of the program. LIHEAP is a federally funded program that provides block grants to the states to use in providing assistance to low income households in meeting their heating needs. PCOC St. 1 at 5. Under both federal law and this Commission's CAP Policy Statement, the combination of the taxpayer-funded LIHEAP program and the ratepayer-funded CAP program are to be used to improve the affordability of home energy to the eligible households in the most efficient manner. OCA St. 3-R at 5. In other words, both federal law and the CAP Policy Statement seek to integrate the LIHEAP grants and the CAP program design to help improve the affordability of energy service. See 52 Pa. Code § 69.265(9).

In the CAP Policy Statement and through the long-standing CAP program design in Pennsylvania, the LIHEAP grant was traditionally applied to the CAP credit (the amount paid by non-participating customers) so as to reduce the amount of subsidy that other, non-participating customers were required to pay for the program. Pennsylvania's CAP Policy Statement and

CAP program design provided a successful approach to integrating the LIHEAP grant and resulted in a great expansion of the assistance provided to low income households over the last two decades. Pennsylvania's model was also implemented in many other states, including Colorado, Illinois, Nevada and Ohio. See OCA St. 3-R at 36-46. This method of using the LIHEAP grant to offset the CAP credits was in place for nearly 20 years.

In the summer of 2009, however, the Department of Public Welfare (DPW), the administrator of the federal LIHEAP program in Pennsylvania, issued a new policy directive affecting the integration of the LIHEAP grants and the utility sponsored CAP programs. DPW directed its LIHEAP vendors to apply LIHEAP cash grants to CAP participants' asked to pay amount on their bills. See Re: Customer Assistance Program Policy; Statement Suspension and Revision, Docket No. M-00920345, Order at 2 (Apr. 9, 2010) (Suspension and Revision Order). DPW indicated that it would revoke vendor status for utilities that did not apply LIHEAP grants to CAP customers' asked-to-pay amounts.[18] Id. at 1.

As noted above, prior to DPW's directive, the Commission's regulations required utilities to use the LIHEAP grant to reduce the CAP credits or shortfall – the difference between a CAP participant's full bill at standard residential rates and the CAP participant's percentage of income payment toward that bill. Id. at 3. In response to DPW's directive, the Commission issued an Order suspending two sections of its CAP Policy Statement so that utilities could comply with DPW's directive to apply the LIHEAP grant to the asked to pay amount rather than the CAP credit. Id. at 5. The sections suspended by the Suspension and Revision Order were:

> (ii) A LIHEAP or other energy assistance grant may not be substituted for a participant's monthly payment.

[18] The OCA continues to disagree with DPW's policy directive and submits that this change in policy is not required by federal law. Nevertheless, since the change has been implemented, the issue presented in the prior proceeding at R-2009-2149262, and CAP Plus is the appropriate responsive program design to this new policy directive.

> (iii) The LIHEAP grant should be applied to reduce the amount of CAP credits.

Suspension and Revision Order at 4. See also 52 Pa. Code § 69.265(9)(ii) and (iii).

The problem presented by the DPW directive is that the CAP program already sets the customer's bill at an affordable level using ratepayer subsidies. The DPW directive then requires that an additional subsidy – the LIHEAP grant – be applied to this affordable bill, which lowers the already affordable bill even further. Without a change in the program design, the DPW directive would result in an increase in bills of ratepayers who do not participate in CAP, including low income customers who are not participating in the program. As a result of this impact, the Commission strongly encouraged utilities to submit revised CAP plans that comply with DPW's directive. Suspension and Revision Order at 5.

DPW's directive was addressed in Columbia's 2010 base rate case at Docket No. R-2009-2149262. In that case, OCA witness Roger Colton recommended:

> Columbia adopt a CAP-plus program in response to the DPW directive. Through the CAP-plus approach, in addition to charging its traditional percentage of income payment, Columbia would add a charge to the bills of all CAP participants to generate a revenue stream equal to the total value of LIHEAP grants applied against the asked-to-pay amounts (rather than against the CAP shortfall).

PCOC St. 1 at 18, reproducing OCA St. 4 at 24 (Docket No. R-2009-2149262). Importantly, all CAP customers would be charged the same "plus" amount.

The parties to the 2010 base rate case agreed in the Joint Petition for Settlement that Columbia would implement a CAP-Plus program. See Pa. P.U.C. v. Columbia Gas of Pa., Inc., Docket No. R-2009-2149262, R.D. at 10, 20 (July 19, 2010), adopted by Order (Aug. 18, 2010). Specifically, the parties to the 2010 base rate settlement agreed:

> f. Customer Assistance Program Matters:
>
> (3) Columbia will adopt a CAP-plus program consistent with the CAP-plus program recommended by OCA witness Colton's testimony (OCA Statement No. 4). The Company will work with the interested parties to develop and design interim changes to the CAP payments in time to request and required waiver of its approved universal service plan from the Commission prior to the start of the 2010-2011 LIHEAP season.
>
> (4) If the federal LIHEAP office finds the Pennsylvania [DPW's] construction of the federal statute to be in error, or if DPW rescinds its policy change for any other reason, Columbia will reinstate the process of using LIHEAP grants to reduce the CAP shortfall.

Id. at 10.

As noted above, under the CAP-Plus program, an asked to pay amount is determined for each CAP customer. The first step in determining the asked to pay amount is to select one of four payment options. Once the payment option is selected, a monthly amount is calculated for that option. Then, the Plus amount is added to arrive at the final asked to pay amount for the customer. In this case, the Plus amount is $17 per month, and this same $17 is included in the monthly asked to pay amount for all CAP customers. PCOC St. 1 at 6-7. The Plus amount is determined by taking the total LIHEAP receipts by Columbia for its CAP customers from the prior year and dividing that number by the total number of CAP participants.

The rationale behind the CAP-Plus approach is explained by OCA witness Roger Colton[19] in the current proceeding as follows:

[19] Roger Colton is a principal of Fisher Sheehan & Colton, Public Finance and General Economics in Belmont, Massachusetts. He provides technical assistance to public utilities and primarily works on low income utility issues. Mr. Colton has devoted his professional career to helping public utilities, community-based organizations and state and local governments design, implement and evaluate energy assistance programs to help low income households better afford their home energy bills. He has been involved with the development of the vast majority of ratepayer-funded affordability programs in the nation. In fact, the federal LIHEAP office has contracted with Mr. Colton over the last fifteen years to develop particular information with respect to the integration of ratepayer-funded affordability programs and LIHEAP. See OCA St. 3 at 1-2, App. A; OCA St. 3-R at 2.

> The CAP-Plus program is a mechanism used by Pennsylvania utilities, and the PUC, to help control the costs of delivering rate affordability benefits through the Customer Assistance Program ("CAP"). Through the CAP-Plus program, utilities control the financial obligation on CAP non-participants by requiring an increased payment obligation from CAP participants as compared to the prior CAP program design. The participant payment obligation is what is referred to as the "asked-to-pay" amount.
>
> Given the current structure of CAP programs, the full bill incurred by CAP participants must be paid by either: (1) a participant payment; or (2) a non-participant payment (or a combination of the two). To the extent that participant payments increase, the required payment by non-participants decreases. In contrast, to the extent that participant payments decrease, the required payment by non-participants must increase to make up the difference.
>
> The primary objective of the CAP-Plus program is to reach a reasonable balance between the goal of providing affordable energy to CAP participants, the goal of providing affordable energy to low-income and near-low-income customers who are *not* CAP participants, and the goal of requiring only a reasonable subsidy from non-low-income customers.

OCA St. 3-R at 9.

The impact of the change in the DPW policy, and the failure to properly address that policy in the CAP design, was explained by OCA witness Colton. Mr. Colton testified:

> The costs of the Columbia Gas CAP program are paid by non-CAP residential ratepayers on a dollar-for-dollar basis. This means that even low-income customers pay the costs of CAP if they do not participate in CAP. Indeed, many low-income customers neither participate in CAP nor receive LIHEAP, but would still pay the costs of CAP. In addition, other customers are sufficiently low-income to lack the capacity to afford to pay their home energy bills, but are not so low-income as to qualify for energy assistance (either CAP or LIHEAP). These customers, too, pay for CAP. Finally, whether or not low-income, the dollars that CAP non-participants should pay for CAP must be kept at some reasonable level.

OCA St. 3-R at 10.

Currently, Columbia's non-participating residential customers, on average, paid $71 per year in CAP costs in 2008 and $81 per year in CAP costs in 2009. OCA St. 3-R at 10-11. If the CAP-Plus program had not been implemented, non-participating customers would have paid an *additional* $16 per year to support the program. OCA St. 3-R at 11. This represents a 20% increase in the annual CAP costs paid by non-participants over the 2009 cost. The impact on an overall basis would have been to increase the CAP support from non-participating residential customers by about $4.5 million per year. On the other hand, under the CAP-Plus program, CAP customers are being asked to pay an additional $17 per month, or $204 per year, towards their total energy bill. But when the LIHEAP grant is applied to this asked to pay amount, CAP customers receiving LIHEAP will actually pay ***less*** than under Columbia's prior CAP program design. Looking at the *minimum* LIHEAP benefit of $300 last year, a CAP customer receiving LIHEAP will actually be better-off by $96 under the CAP-Plus Program than under the prior Columbia CAP program. OCA St. 3-R at 12. In no case will a CAP participant receiving LIHEAP be worse off under the CAP-Plus program than under the original program design. The OCA acknowledges that CAP customers that do not apply for a LIHEAP grant or who do not assign the LIHEAP grant to Columbia will pay more under the CAP-Plus program. That outcome, however, is a result of the DPW policy directive.

Even with the higher asked to pay amount under the CAP-Plus program, though, the percentage of a CAP customer's income that goes toward the energy bill remains within (or very close to) the guidelines established by the Commission in its CAP Policy Statement. OCA St. 3-R at 14. That is, even if a CAP customer does not apply for LIHEAP, or does not assign the LIHEAP grant to Columbia, the customer's asked to pay amount under the CAP-Plus program will still be within, or very close to, the affordable percentages of incomes identified in the Commission's CAP Policy Statement. OCA St. 3-R at 14; CPA St. 117-R at 11-12.

The CAP-Plus program implemented by Columbia as a response to the DPW directive is an essential element of the program that properly balances the interests of both CAP customers and non-participating residential customers in a manner that is targeted, reasonable and fully in compliance with federal law.[20] In this case, PCOC challenges the CAP-Plus program and would eliminate the Plus amount component of the asked to pay portion of the CAP customer's bill. In essence, PCOC urges the Commission to ignore the impact on non-participating residential customers of the significant change in DPW policy regarding the integration of the LIHEAP grant with the CAP programs. PCOC argues that both federal law and public policy considerations support a Commission decision to disregard the impact of the DPW directive on non-CAP customers and to reduce the affordable bills of CAP customers even further. As much as the OCA would have preferred to continue all aspects of the prior program design, including the application of the federal LIHEAP grant to the CAP credits rather than the asked to pay amount, DPW has persisted in its new policy (which has not been adopted in any other state), and the Commission cannot simply ignore this sea change in program integration or cost consequences for the residential customers who pay for 100% of the costs of this program, including low income non-CAP customers.

As will be detailed below, the PCOC criticisms of the CAP-Plus program are without merit and legally unsustainable. PCOC's call to eliminate the Plus amount and ignore the impact of the change in DPW's policy would result in the affordable bill provided to the CAP customer being reduced even further, and in fact to zero in some instances. And, it would result in the

[20] As will be discussed in Section III.B.4, the OCA recommends one slight modification to the CAP Plus program to ensure that the "Plus amount" does not get out of line with the LIHEAP appropriation to the Commonwealth so that the integration of the benefits remains consistent.

costs of the program increasing to all other residential customers. This result has clearly been rejected by the Commission as a proper way to integrate the new DPW directive regarding LIHEAP into the CAP program design. See generally Suspension and Revision Order. PCOC's positions must be rejected and the CAP-Plus program should be affirmed by the Commission.

2. The CAP-Plus Program Meets The DPW Directive In A Manner That Complies With Federal Law.

As noted, Columbia has operated a CAP program for decades with the goal of assisting low income, payment troubled customers to afford their natural gas service. Under Columbia's program, the CAP customer is asked to pay a portion of their total natural gas bill. The portion that the customer must pay is referred to as the "asked to pay amount." Under the CAP-Plus program, Columbia determines the asked to pay amount by first selecting one of four payment options. The payment options are: 1) a percentage of income plan (PIPP); 2) the average of the customer's last 12 months of payments; 3) a discounted bill equal to 50% of the customer's Budget Billing amount; or 4) a discounted bill equal to75% of the customer's Budget Billing amount (for selected seniors). OCA St. 3-R at 17. To these amounts, Columbia adds a "Plus amount" to arrive at the final asked to pay amount for the CAP customer. At this time, the Plus amount is $17 per month, and the same $17 per month is included in all CAP customers' asked to pay amounts. If a CAP customer receives a federal LIHEAP cash grant during the winter heating season, that grant is applied to the customer's asked to pay amount, thus reducing the amount that the CAP customer remits to Columbia.

In this case, PCOC has challenged Columbia's approved CAP-Plus program and seeks to eliminate the Plus component of the asked to pay amount. PCOC's arguments regarding the CAP-Plus are two-fold. PCOC asserts that: (1) the program does not comply with federal law and Pennsylvania's LIHEAP State Plan for 2010-2011 and (2) from a public policy perspective, the program is flawed. See PCOC St. 1 at 2-3. Based on these concerns, PCOC asserts that Columbia's universal service rates under the CAP-Plus program are not just and reasonable. Id. at 20. The OCA submits that PCOC's criticisms of the CAP-Plus program are without merit and must be dismissed. The CAP-Plus program fully complies with federal and state law, and reasonably addresses the significant change in DPW policy regarding the integration of the LIHEAP grant and ratepayer-funded Customer Assistance Programs operated by Pennsylvania's regulated distribution utilities.

a. Introduction

The federal LIHEAP program is administered by the Energy Assistance Division of the Administration for Children and Families (ACF) of the U.S. Department of Health and Human Services (HHS). For many years, the federal LIHEAP office has devoted attention to the issue of the integration of the federal LIHEAP effort with ratepayer-funded energy affordability programs such as CAP. As OCA witness Colton explained in his testimony, Mr. Colton has worked closely with the federal LIHEAP office on these efforts, both chairing some of these efforts and preparing handbooks and workbooks on integration issues. OCA St. 3-R at 3.

There are two primary reasons for the focus of efforts to integrate and coördinate energy affordability programs. First, "Assurance Four" of the federal LIHEAP statute requires states each year to integrate LIHEAP with other state and federal programs where appropriate. 42 U.S.C. § 2605(b)(4). The LIHEAP statute provides that the chief executive officer of each state shall certify that the state agrees to "coordinate its activities under this title with similar and related programs administered by the Federal Government and such State, particularly low-income energy-related programs . . .." OCA St. 3-R at 4-5. Second, pursuant to the federal

Government Performance and Results Act of 1993 (GPRA), all federal agencies are to focus on "results" rather than activities. 103 P.L. 62 § 2(b)(3). According to OCA witness Colton:

> Under GPRA, 'a focus on results, as envisioned by the Results Act, implies that federal programs contributing to the same or similar results should be closely coordinated to ensure that goals are consistent and that, where appropriate, program efforts are mutually reinforcing.' Having agencies coordinate efforts with related strategic or performance goals is a specific purpose behind the GPRA. According to the federal General Accounting Office ("GAO"):
>
> > Coordination among federal programs with related responsibilities is essential to efficiently and effectively meet national concerns. Uncoordinated program efforts can waste scarce funds, confuse and frustrate program customers, and limit the overall effectiveness of the federal effort. A focus on results, as envisioned by the Results Act, implies that federal programs contributing to the same or similar results should be closely coordinated to ensure that goals are consistent and that, where appropriate, program efforts are mutually reinforcing.
>
> The rationales stated in this GAO review of the need for integration efforts are particularly appropriate to remember in considering the Columbia Gas CAP-Plus program. There is a need to 'efficiently' meet national concerns; there is a need to avoid the 'waste [of] scarce funds;' there is a need to ensure that 'program efforts are mutually reinforcing.'

OCA St. 3-R at 3-4. (Footnotes omitted).

Since their inception, Pennsylvania's Customer Assistance Programs have integrated the LIHEAP grant in the program design to achieve a program that efficiently utilizes resources to improve the affordability of the energy bill for low income, payment-troubled customers. When DPW issued its directive that changed the manner in which the LIHEAP grant could be integrated with the CAP, it was necessary to modify the program design to continue to ensure the efficient use of the scarce resources and to ensure that the program efforts were "mutually reinforcing" in achieving the goal of improving affordability of the energy bill. Mr. Colton explained:

> The Columbia Gas CAP program is not to be implemented in isolation of LIHEAP. That has never been the approach of the PUC. Nor is it consistent with principles governing the LIHEAP program. Rather than insisting that CAP be implemented without consideration of LIHEAP, the CAP and LIHEAP programs should be "closely coordinated." The programs should be designed and delivered in a way to ensure that they are "mutually reinforcing."

OCA St. 3-R at 8.

While the federal and state programs must be mutually reinforcing, it is important to note that the scope of concern of ACF/HHS and DPW, as the LIHEAP coordinator, in administering LIHEAP is narrower than the scope of concern of this Commission in administering CAP. As explained by OCA witness Colton:

> The concern of ACF/HHS and DPW is exclusively with the impact that LIHEAP program benefits have on LIHEAP recipients. Moreover, the concern of ACF/HHS and DPW is exclusively with the affordability of heating service during the heating season. In contrast, the concern of the PUC is much broader. The PUC is concerned with the affordability of home energy both to CAP participants who receive LIHEAP and those that do not. As importantly, the PUC is concerned with the continuing affordability of home energy to low-income customers who might be income-qualified for LIHEAP, but who (for whatever reason) do not apply for and receive it. Equally importantly, the PUC must be concerned with all residential customers, including those who are *not* income-qualified for either LIHEAP *or* CAP but nonetheless still do not have sufficient household resources to be able to pay their home energy bills in a full and timely fashion.

OCA St. 3-R at 5-6. Consequently, while ACF/HHS and DPW may determine how to apply LIHEAP benefits, it is this Commission that sets the amount of CAP customers' bills that it finds to be reasonable and affordable.

The OCA submits that Columbia's CAP-Plus program achieves the goals of both federal and state law. The program improves the affordability of the low income household's energy bill, it properly integrates the LIHEAP grant in the program design, and it does not unduly burden non-participating residential customers with excessive or unnecessary costs. In contrast, the proposal of PCOC to eliminate the Plus component and still apply the LIHEAP grant to the asked to pay amount is not reasonable nor is it fair. OCA witness Colton testified:

> The proposal advanced by Mr. Bertocci, even if it increases the affordability of home energy to LIHEAP customers who are also CAP participants, generates a detrimental impact on LIHEAP customers who are *not* participants in CAP, as well as a detrimental impact on all other poor and near-poor customers that do not participate in LIHEAP. Mr. Bertocci's proposal also generates a detrimental impact on all other residential ratepayers. While ACF/HHS and DPW, as administrators of the LIHEAP program, need not concern themselves with these other residential customer populations that do not participate in LIHEAP, the PUC does not have that luxury. This seeming conflict, however, is not irreconcilable. The reconciliation of these competing interests occurs through continuing the CAP-Plus program that the PUC already approved for Columbia Gas (in 2010) along with those CAP-Plus programs approved for other Pennsylvania utilities.

OCA St. 3-R at 8.

As will be discussed in more detail below, the Columbia CAP-Plus program provides a reasonable, measured response to the change in DPW's directive regarding the integration of the LIHEAP benefits with the ratepayer-funded CAP program. The CAP-Plus program meets all legal and statutory requirements and is well within this Commission's jurisdiction to both approve and implement. The OCA submits that Columbia's CAP-Plus program should be affirmed and continued.

b. CAP-Plus Does Not Treat LIHEAP as a Resource Nor Does It Adversely Treat LIHEAP Recipients.

i. Introduction

PCOC witness Philip Bertocci asserted that the CAP-Plus program violates federal law because (1) CAP-Plus considers LIHEAP as a resource of the household and (2) CAP-Plus discriminates against LIHEAP recipients because the program adversely treats those customers due to their participation in, or eligibility to participate in, LIHEAP. PCOC St. 1 at 15-17. These statutory arguments are fundamentally flawed and must be rejected.

As an initial matter, the underlying premise of PCOC witness Bertocci's argument is that this Commission does not have the authority to modify, or even establish, the payment responsibility of CAP participants. That is, Mr. Bertocci argues that this Commission is without authority to set the "asked to pay amount" for CAP customers to control the cost impacts of CAP on program non-participants because to do so would result in LIHEAP "subsidizing" the CAP program. See OCA St. 3-R at 16. The OCA respectfully submits that this underlying premise is fundamentally flawed and improperly colors the remainder of Mr. Bertocci's analysis. OCA witness Colton identified this fundamental error in PCOC's statutory analysis:

> Even if the DPW may have the authority under the federal LIHEAP statute to dictate that LIHEAP be applied only against a low-income customer's asked-to-pay amount, it is the PUC, not the DPW, that has the authority to define what the asked-to-pay amount is in the first instance. The DPW does not, by virtue of its distribution of LIHEAP benefits, gain authority over determining the design or level of the bills that low-income customers are asked-to-pay.

OCA St. 3-R at 17.

It is important to recognize that under a CAP program, a low income customer is not asked to pay their entire utility bill, but is only asked to pay a portion of that utility bill. The amount of the bill that the CAP customer must pay is determined through the program design and approved by the Commission. In the CAP-Plus model, the final asked to pay amount for *all* CAP customers includes a Plus amount, in this case an amount of $17 per month. The greatest complaint of PCOC seems to be that in determining the Plus component of the final asked to pay amount, the CAP-Plus model uses the total LIHEAP receipts by Columbia for its CAP customers from the prior year. Using the total LIHEAP receipts from the prior year tries to narrowly target the change in the method of integrating LIHEAP into the CAP program occasioned by the change in DPW's directive so that the balance between participating and non-participating customers that has been achieved over the 25 years of program operation can best be maintained. The Commission, however, could set the asked to pay amount in any reasonable manner it so chooses to ensure the proper control of the costs of the CAP. OCA witness Colton provided some examples of actions within the Commission's authority as it regards the four options that Columbia uses in its program:

> In response to the DPW directive, the PUC could, within its regulatory authority, direct CGPA:
>
> - Option 1: to use an "affordability range" of 10 – 15% rather than 7 – 9%;
>
> - Option 2: base bills on 110% of the average of the last 12 months of payments (rather than on 100% of the average of the last 12 months);
>
> - Option 3: set the discounted bill equal to 60% of the customer's Budget Bill, rather than equal to 50% of the Budget Bill;
>
> - Option 4: set the discounted bill equal to 85% of the customer's Budget Bill, rather than equal to 75% of the Budget Bill.
>
> If any of these decisions were made, even if calculated to have a fiscal impact to offset the increased costs caused by

> implementation of the DPW directive, the DPW would have no authority to override the PUC decision by asserting that the PUC's change in the asked-to-pay amount resulted in LIHEAP "subsidizing CAP."

OCA St. 3-R at 17-18. OCA witness Colton further explained some Commission options:

> The Commission might decide to increase the minimum payment amount. The Commission might reduce the CAP credit ceiling. The Commission might impose budget ceilings on CAP costs (either on an aggregate basis or on a per unit of gas basis). The Commission might impose limits on the number of customers allowed to participate in CAP. In none of these cases, even if done to control overall CAP costs in light of higher CAP costs attributable to complying with the DPW directive, would DPW have a legitimate basis to argue that the Commission lacked decision-making authority to control CAP costs because to do so would result in "LIHEAP subsidizing CAP."
>
> * * *
>
> I merely note that they are all alternative mechanisms that the PUC might have available to accomplish the same objective as would be accomplished by adopting CAP-Plus, to control CAP costs in light of the increased costs associated with the implementation of the DPW directive. If the PUC has the authority to increase CAP asked-to-pay amounts by increasing the percentage of income payment by some percentage of the PUC's choosing, it must also have the authority to do the same thing by increasing the asked-to-pay amount by a specified dollar amount instead. If the PUC has the authority to increase CAP asked-to-pay amounts by decreasing the bill discount by some percentage of the PUC's choosing, it must also have the authority to do the same thing by defining the decreased discount in dollar terms instead. Even if DPW has the authority to dictate that LIHEAP be applied against the asked-to-pay amount under the LIHEAP statute, that authority does not give DPW the authority to define what the asked-to-pay amount should be in the first instance.

OCA St. 3-R at 18-19.

The LIHEAP statute does not require the Commission to set the level of the asked to pay amount for CAP customers at a specified amount; it does not require the Commission to establish a specific level of affordability that must be attained by a ratepayer-funded program;

and it does not establish a specific level of ratepayer funding for such programs. When the LIHEAP statute is properly viewed, the fundamental flaws in the PCOC analysis become apparent.

ii. The CAP-Plus Program Does Not Treat the LIHEAP Grant as a Resource.

PCOC's first argument is that the CAP-Plus model treats a customer's LIHEAP grant as a "resource" and thus, is inconsistent with federal law that precludes such treatment. PCOC witness Bertocci argued that Columbia does so because it uses the total amount of LIHEAP cash grants the Company received in the prior year for its CAP customers when calculating the Plus amount. PCOC St. 1 at 7. As noted above, the use of the total LIHEAP receipts to establish the Plus amount is simply one of many approaches the Commission could use to determine the final asked to pay amount. The use of total LIHEAP receipts for CAP customers, however, better ensures that the balance that was achieved between participants and non-participants in the prior program design, where the LIHEAP grant was applied to the CAP credits, is maintained. Any other proxy could be used to establish the asked to pay amount if the Commission determined this to be appropriate and necessary.

Use of the total LIHEAP receipts, though, does not treat the individual LIHEAP grant as a resource, contrary to PCOC's argument. The LIHEAP statute states:

> the amount of any home energy assistance payments or allowances provided directly to, or indirectly for the benefit of, an eligible household under this title shall not be considered income or resources of such household (or any member thereof) for any purpose under any Federal or State law, including any law relating to taxation, food stamps, public assistance, or welfare programs.

42 U.S.C. § 2605(f)(1).

As OCA witness Colton pointed out, the CAP program is not a "public assistance or welfare program." Rather, it is an alternative utility payment plan under which a utility provides a bill to a customer at less than the standard residential bill or rate in exchange for the customer making full and timely payment of this lower amount. OCA St. 3-R at 21. But even if the LIHEAP statute arguably could be applied to the CAP program, the statute only prohibits consideration of the amount of the LIHEAP grant to a specific household. The statute does not prohibit consideration of the amount of LIHEAP grants in the aggregate that are available for integration with the design of the state program. Mr. Colton summarized the impact of the LIHEAP statute if it were applicable to the CAP as follows:

> What the federal LIHEAP statute does is to prohibit the PUC from decreasing the CAP benefits provided to a specific household based upon the amount of any home energy assistance payments which *__that household__* receives. Under the statute, the rule quite simply is that a state may not give a person receiving LIHEAP less aid than it would grant a person who is otherwise similarly situated but who is not receiving LIHEAP. The Columbia Gas CAP-Plus program does not fall afoul of this prohibition. CAP participants receiving LIHEAP, and CAP participants *__not__* receiving LIHEAP, are treated identically if they are otherwise similarly situated.

OCA St. 3-R at 22.

In the CAP-Plus program, the amount of assistance that a *specific* household receives is not considered in the determination of the asked to pay amount. Nor does the Plus amount change based on whether or not the customer receives a LIHEAP grant. OCA witness Colton explained why PCOC's claim to the contrary is unfounded as follows:

> The "plus" amount imposed as an additional CAP payment is unrelated to the amount of LIHEAP received by any given CAP participant, as well as unrelated to whether or not a CAP participant receives LIHEAP at all. A CAP participant receiving $100 in LIHEAP benefits is billed the same "plus" amount as the CAP participants receiving $500 in LIHEAP benefits. A CAP

> participant receiving *no* LIHEAP benefits (i.e., is a LIHEAP non-recipient) is billed the same "plus" amount as the CAP participant who receives a $500 benefit. In each case, the CAP participant, to the extent that he or she receives LIHEAP (if at all), would apply that LIHEAP benefit against his or her asked-to-pay amount. The asked-to-pay amount, however, does not change based on whether or not a LIHEAP benefit is received, or based on what the level of that benefit (if any) might be.

OCA St. 3-R at 22-23.

The LIHEAP grant is never treated as a resource under the CAP-Plus program that would change the amount that a specific LIHEAP recipient is asked to pay. The CAP customer can apply for LIHEAP and assign the grant to Columbia, apply for LIHEAP and assign the grant to a different energy provider, or not apply for LIHEAP at all. Under all three circumstances that CAP customer is treated identically in that the CAP-Plus amount would be the same, the asked to pay amount would be the same (if their bills were otherwise identical), and the forgiveness of pre-program arrears would be the same. OCA St. 3-R at 23. It is abundantly clear that the CAP-Plus program does not treat LIHEAP as a resource or otherwise violate the federal law.

iii. The CAP-Plus Program Does Not Adversely Treat LIHEAP Recipients.

PCOC also argues that the CAP-Plus program adversely treats LIHEAP recipients contrary to the requirements of the federal LIHEAP statute. PCOC reaches this conclusion by trying to find differences in the charges between CAP and non-CAP low income customers, and differences in the amounts that CAP customers ultimately pay if they are eligible for a LIHEAP grant but do not receive one. These arguments are unfounded.

The LIHEAP statute states: "no household receiving assistance under this title will be treated adversely because of such assistance under applicable provisions of State law or public regulatory requirements." 42 U.S.C. § 8605(b)(7). OCA witness Colton made three observations with regard to this language. First, the statute applies to persons receiving assistance and not to all persons eligible to receive assistance. Second, this section stands for the proposition that a customer receiving assistance cannot bear an obligation that is not imposed on a person not receiving LIHEAP. And third, the statute requires a causal connection between the receipt of LIHEAP and the adverse treatment. OCA St. 3-R at 25. The Columbia CAP-Plus program does not run afoul of any of these prohibitions.

Under its CAP-Plus program, Columbia treats CAP/LIHEAP recipients exactly the same as non-CAP/LIHEAP recipients, and it treats CAP/LIHEAP recipients exactly the same as it treats CAP/non-LIHEAP recipients. Turning first to CAP participants, as demonstrated in the chart below, CAP participants are treated the same whether they obtain LIHEAP or not either this year or in the past:

CAP Participant	Received LIHEAP "this year"?	Received LIHEAP "last year"	CAP-Plus Amount
1	Yes	Yes	$17/month
2	No	No	$17/month
3	No	Yes	$17/month
4	Yes	No	$17/month

OCA St. 3-R at 27. This chart clearly shows that all CAP customers are treated the same and therefore, none are treated adversely.

Within the CAP-Plus program, there is no different treatment for a customer based on whether or not the customer receives LIHEAP. OCA witness Colton summarized:

> ➢ The asked-to-pay amount is calculated in an identical fashion for LIHEAP recipients and LIHEAP non-recipients under CAP-Plus;
>
> ➢ The selection of the Payment Option is determined in an identical fashion for LIHEAP recipients and LIHEAP non-recipients under CAP-Plus;
>
> ➢ The grant of arrearage forgiveness is determined in an identical fashion for LIHEAP recipients and LIHEAP non-recipients under CAP-Plus;
>
> ➢ The posting of customer payments and LIHEAP payments against "CAP bills" is performed in the identical fashion for LIHEAP recipients and LIHEAP non-recipients;

OCA St. 3-R at 30. Under Columbia's CAP-Plus, LIHEAP recipients have no burden or obligation under CAP-Plus that is in addition to, or different from, LIHEAP non-recipients. Similarly, LIHEAP non-recipients have no benefit conferred upon them that is not equally available to and conferred upon LIHEAP recipients. There is no adverse impact from receiving a LIHEAP grant under Columbia's program. Indeed, there is only a benefit for the CAP participant in receiving the LIHEAP grant as it is now used to reduce the asked to pay amount, thus lowering the recipient's ultimate payment to Columbia.

PCOC also attempts to claim an adverse treatment of CAP LIHEAP recipients by comparing CAP LIHEAP recipients to non-CAP LIHEAP recipients. The gravamen of the PCOC argument is that if a Plus amount is added to the asked to pay amount of a CAP customer, it must also be added to the bill of a non-CAP customer receiving LIHEAP. PCOC St. 1-SR at 15-16. This comparison is flawed for at least two reasons. First, the Plus amount is added to all CAP customers' bills, not just LIHEAP recipients. Singling out only non-CAP LIHEAP recipients as Mr. Bertocci suggests would actually discriminate against those customers for receiving LIHEAP.[21]

More fundamentally, PCOC overlooks the fact that the non-CAP customer is already paying their ***total*** monthly energy bill while the CAP customer is only being asked to pay a ***portion*** of the total energy bill. The CAP-Plus program is simply determining the portion of the bill that the CAP customer is asked to pay. In this instance, the formula for determining the final asked to pay amount for CAP customers adds $17 per month to the payment option selected. It is abundantly clear that there is no need to add an additional $17 per month to a full bill under the LIHEAP statute. The CAP/LIHEAP customer and the non-CAP/LIHEAP customers are not similarly situated for purposes of the comparison that PCOC seeks to make.

Even so, however, there is no difference in the way the customers are treated with respect to the LIHEAP grant. Columbia applies the entire LIHEAP grant to each customer's asked-to-pay amount, whether that is the full bill or the discounted bill. OCA St. 3-R at 25-26. For the CAP participant, the asked to pay amount is a function of the CAP program design, not LIHEAP participation. For the non-CAP customer, the asked to pay amount is the total energy bill for the month and is not a function of LIHEAP participation. OCA St. 3-R at 26. For both CAP and non-CAP customers, the LIHEAP grant is applied to the customer's payment responsibility to reduce that payment obligation. Additionally, under the Columbia CAP-Plus program, the LIHEAP benefits are posted to each customer's bill in the same way that any other external bill payment assistance is applied. Id. at 26. There is no difference in the treatment of CAP/LIHEAP recipients as compared to non-CAP/LIHEAP recipients.

[21] It must also be remembered that the non-CAP LIHEAP recipients are paying the Universal Service Program Rider and are thus, paying the costs of the program for the CAP customers.

PCOC's argument that the CAP-Plus program adversely treats LIHEAP recipients cannot be supported. The CAP-Plus program treats all LIHEAP recipients the same, particularly as it concerns the application of the LIHEAP grant to the payment obligation. CAP-Plus does not violate any federal statutory prohibitions regarding the treatment of LIHEAP recipients.

iv. The Information Memo and DPW Letters Do Not Support PCOC's Argument.

PCOC also attempts to rely on three documents to support its position regarding the Columbia CAP-Plus program. First, it references an Information Memorandum (LIHEAP-IM-2010-13) issued by the federal LIHEAP Office regarding "Use of LIHEAP Funds Coordinated with Vendor Assistance Programs." PCOC St. 1 at 15-16. Second, PCOC relies on a Letter from DPW regarding the universal service program proposed by Philadelphia Gas Works. Id. at 16-17. Third, PCOC points to a DPW letter authored by Philip E. Abromats and submitted to the Secretary of the Commission on June 3, 2011.[22] None of these documents can be used to overturn the validity of the Columbia CAP-Plus program.

Turning first to the Information Memorandum (IM), it is important to note that the IM was considering a program design that preceded the development of the CAP-Plus Program. The CAP-Plus is a different program than that under consideration when the IM was issued. OCA St. 3-R at 35-36. The IM has no applicability to the CAP-Plus program. Moreover, as OCA witness Colton discussed, the Pennsylvania DPW is the only state agency in the Nation that reached the conclusions forwarded by PCOC witness Bertocci regarding the applicability of the IM to percentage of income plans such as the Pennsylvania CAPs. Mr. Colton testified:

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[22] ALJ Dunderdale took notice of this DPW letter pursuant to 52 Pa. Code § 5.408 at hearings in this matter. However, the ALJ made clear that she was not allowing the letter into the record "for the truth of the facts stated therein." Tr. 130. Instead, the ALJ took notice of the fact that DPW submitted a letter to the Secretary of the Commission and that the letter proffers a legal conclusion that Columbia's CAP Plus program is impermissible under federal law and makes a statement that DPW is considering withdrawing Columbia's LIHEAP vendor status. Tr. 129-30.

> The Pennsylvania DPW continues to stand alone amongst state LIHEAP offices in reaching the conclusions that it has reached regarding the interaction between ratepayer-funded rate affordability programs and LIHEAP. Every percentage of income plan with which I have worked throughout the nation applies the LIHEAP grant to the shortfall between the percentage of income payment and the bill at standard residential rates so that, in combination, the ratepayer-funded program and LIHEAP grant will reduce the program participant's bill to an affordable percentage of income. This is the program design that was used in Pennsylvania for all PIPPs for the last 25 years until this PA DPW directive. Only in Pennsylvania has the state LIHEAP office asserted that ratepayer funds must be used to reduce the client bill to an affordable percentage of income with LIHEAP benefits providing an additional home energy bill payment to reduce the bill payment even further.

OCA St. 3-R at 35. (See OCA St. 3-R at 36-46 for a discussion of four states that continue to utilize the program design that Columbia and Pennsylvania previously employed). The IM simply has no relevance, though, to the consideration of Columbia's CAP-Plus program.

DPW's Letter regarding the PGW program is also inapposite to the Commission's consideration of the Columbia CAP-Plus program. While not at all agreeing with DPW's analysis or conclusions regarding PGW's program, OCA witness Colton highlighted the following distinctions between the two programs:

> ➢ Columbia Gas does not add a dollar amount "to reflect the fact that these customers will either receive a LIHEAP Cash Grant or will be eligible to receive a LIHEAP Cash Grant. . ." (DPW PGW Letter, at 2);
>
> ➢ Columbia Gas does not "subtract the whole LIHEAP benefit [or] subtract any part of that benefit, however estimated. . ." (DPW PGW Letter, at 2).
>
> ➢ Columbia Gas does not "add a LIHEAP Cash Adjustment to the bills of [CAP] heating customers to reflect the fact that these customers will either receive a LIHEAP Cash Grant or will be eligible to receive a LIHEAP Cash Grant. . ." (DPW PGW Letter, at 3);

> ➢ Columbia Gas does not add a bill adjustment "which [is] projected for each customer as a proportion of his/her eligible grant according to the LIHEAP benefits table. . ." (DPW PGW Letter, at 3).; and
>
> ➢ Columbia Gas does not "propose larger dollar increases in the asked-to-pay amount above existing levels for the poorer LIHEAP recipients who receive the largest amount. . ." (DPW PGW Letter, at 3).
>
> In addition to this fundamental structural difference between the PGW proposal and the Columbia Gas program, neither does Columbia Gas divide the LIHEAP Cash Grant into equal monthly installments to apply to budget billing amounts (DPW PGW Letter, at 3).

OCA St. 3-R at 49-50. The DPW PGW Letter cannot be used to form any conclusions regarding the Columbia CAP-Plus program.

Late in the proceeding, after an Application for Subpoena, DPW provided a Letter to Secretary Chiavetta in lieu of appearing pursuant to a subpoena requested by PCOC regarding the Columbia CAP-Plus Program. However, as explained above, the ALJ admitted this Letter conditionally. The condition is that it is not admitted not for the truth of the matter asserted. The DPW Letter regarding Columbia's CAP-Plus program cannot support any conclusion regarding the Columbia program. Initially, it must be noted that the author of the Letter acknowledges that he has not reviewed Columbia's CAP-Plus model and is not familiar with that model. This is in direct contrast to OCA witness Colton, an attorney and nationally recognized expert regarding CAP programs and the federal LIHEAP program, who thoroughly analyzed the program as well as state and federal law. Second, the DPW Letter appears to rely on incorrect assumptions about the Columbia CAP-Plus program. In OCA St. 3-SR, Schedule RDC-1SR, OCA witness Colton provides a statement of facts about the Columbia program that are relevant to the inquiry. The

OCA submits that specific facts as set forth in Mr. Colton's Schedule RDC-1SR should be adopted by the ALJ and the Commission.

The DPW Letter makes the following errors that are fatal to the analysis:

> --the Letter suggests that the CAP-Plus program does not provide the LIHEAP benefit to the individual LIHEAP recipient when in fact the program specifically posts the LIHEAP credits to the asked to pay amount of the individual customer;
>
> --the Letter suggests that the CAP customer does not receive the full benefit of the LIHEAP grant when the full benefit is applied directly to offset the amount of the bill that the customer is asked to pay;
>
> --the Letter suggests that the individual LIHEAP grant is taken into consideration in deciding the level of the bill for a particular customer when no such consideration is given to an individual customer's LIHEAP grant.

OCA St. 3-SR at 5-6. Moreover, the OCA submits that the legal analysis contained in the DPW letter is flawed for the same reasons as discussed above in Section III.B.2 regarding PCOC's statutory and legal arguments.

The DPW Letter regarding Columbia's CAP-Plus program is flawed in that, without review of the CAP-Plus program or discussion with Columbia, DPW calls into question Columbia's vendor status as well as the authority of this Commission to determine the amount of a bill that a CAP customer can be asked to pay in Pennsylvania. The OCA urges the Commission to reject the conclusions of this letter, but also urges the Commission to open a discussion with DPW so that the full facts can be made known to DPW and these matters finally resolved.

v. Conclusion

For the reasons detailed herein, and in the testimony of OCA witness Roger Colton, the OCA submits that PCOC's claims that Columbia's CAP-Plus program violates federal LIHEAP statutes are flawed and unfounded. The Columbia CAP-Plus program provides a reasonable means to integrate the LIHEAP grant with the ratepayer-funded CAP program as required by federal law and this Commission. The Columbia CAP-Plus program does so in a manner that is fully in accord with the federal LIHEAP statute and in a manner that is fair and reasonable. As such, PCOC's criticisms of the program, and its alternative proposal to eliminate the Plus component of the program, must be rejected.

3. CAP-Plus Is in the Public Interest and Constitutes Sound Public Policy.

PCOC argues that other public policy considerations support the elimination of the CAP-Plus program and instead leave the prior CAP asked to pay amount in place and then apply the LIHEAP grant to the already affordable asked to pay amount. As explained above, such a result would unduly burden non-CAP residential customers, including low income and moderate income customers, who must bear 100% of the cost of the CAP programs. PCOC asserts, however, that Columbia's CAP-Plus places the greatest new burdens on the poorest customers, which does not constitute sound public policy. PCOC St. 1 at 17. According to PCOC witness Bertocci, the $17 per month CAP-Plus amount will, for households with income at or below 100% of Federal Poverty Level (FPL), increase their annual asked-to-pay amount by between 20% and 68% for a two-person household and by between 15.89% and 60.74% for a three-person household. PCOC St. 1 at 10. PCOC asserts that the additional costs imposed by the DPW directive should be borne by Columbia's non-CAP residential customers via the USP rider, since it would only add about $16.08 per year to their bills ($1.34/month * 12 = $16.08) PCOC St. 1 at 20.

First, it should be noted that, even with the Plus amount added to CAP bills, and even assuming the customer receives no LIHEAP grant, in almost every instance for households with income greater than 50% of FPL, the CAP payment remains in the range of reasonableness in the

CAP Policy Statement. OCA St. 3-R at 14, citing 52 Pa. Code § 69.265(2)(B). The one exception is two-person households at 125% of FPL, whose CAP-Plus burden is at 10.14%, while the upper range identified for this household in the CAP Policy Statement is 10%. Id. These CAP payments remain within, or very close to, the percentages identified in the CAP Policy Statement even without considering the application of the LIHEAP grant to the asked to pay amount.[23] As Columbia witness Davis testified, a review of existing CAP accounts showed that only 856 of the accounts had an energy burden above 10% of the household income before the application of a LIHEAP grant. CPA St. 117-R at 11. Columbia witness Davis also testified that when the LIHEAP grant is applied to the asked to pay amount, some customers have a bill of zero for many of the winter months. Id.

Even those CAP-Plus customers with incomes below 50% of FPL are better off under the CAP-Plus program if they obtain LIHEAP benefits. OCA St. 3-R at 14. That is, while CAP customers are paying a Plus amount of $17 per month (or $204 per year), the CAP customer can apply for a LIHEAP benefit of up to $1,000 (for those with the lowest incomes) to be applied to the asked to pay amounts. This still leaves the lowest income households who receive the maximum benefit nearly $800 better off than under the prior approach when LIHEAP benefits were applied to the CAP shortfall. OCA St. 3-R at 14. Even those CAP customers receiving the minimum LIHEAP benefit of $300 would be better off under CAP-Plus by $96 ($300 - $204). OCA St. 3-R at 12. Prior to the DPW directive, Columbia would have applied the entire LIHEAP benefit to the CAP shortfall.[24] OCA St. 3-R at 12.

[23] In his Surrebuttal Testimony, PCOC witness Bertocci takes issue with Mr. Colton's calculation in this regard. The differences between Mr. Bertocci's calculation and Mr. Colton's appear to be related to rounding conventions. Even under Mr. Bertocci's calculations, the percentage of income payments remain very close to the 10% guideline in the CAP Policy Statement.

[24] This impact can be illustrated by PCOC's named complainants. During the 2010-2011 LIHEAP grant period, the complainants' CAP bills could have been reduced to $9.33 per month and $15.33 per month, respectively, had they

In contrast, as noted by OCA witness Colton, since non-CAP residential customers paid, on average, $81 per year for CAP costs in 2009, PCOC's recommendation to charge non-CAP residential customers the costs of the DPW directive would amount to a 20% increase on average in CAP costs in 2009 ($16.08/$81 = 0.199).[25] OCA St. 3-R at 11. Yet, while the Plus amount adds $17 per month, or $204 per year, to all CAP participants' bills, the application of LIHEAP benefits will leave CAP customers better off than they would have been without the DPW directive and CAP-Plus. Id. at 12.

Moreover, basing public policy considerations solely on the impact on the lowest income households must be approached with great caution. As OCA witness Colton explained:

> It would be a mistake to make a generally applicable policy based upon the impact of the policy on households with reported income of less than 50% of the Federal Poverty Level. Even the Pennsylvania LIHEAP State Plan expresses the need for caution in addressing the needs of households with these very low incomes. The 2011 LIHEAP State Plan provides: "if the applicant states that the household has minimal or no income, the applicant shall be required, as a condition of eligibility, to produce evidence that will satisfactorily explain how the household members are meeting their financial obligations and basic living needs." (Pennsylvania LIHEAP State Plan, Section 601.103). That "evidence" required by the LIHEAP State Plan as a condition of LIHEAP eligibility is not provided to Columbia Gas, nor is it used in the calculation of CAP benefits.

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applied for LIHEAP and assigned their benefits to Columbia. CPA St. 117-RJ at 4, 6. Columbia's gas rates are decreasing, so as of June 1, 2011, and CAP asked to pay amounts will decrease as well. Id. at 2. Therefore, if the complainants apply for LIHEAP and assign their benefits to Columbia for the 2011-2012 LIHEAP grant period, their bills could be zero and $7.33 per month, respectively. Id. at 4-5, 7. Since the complainants are paying a $17 per month Plus amount and their monthly bills, if they obtain LIHEAP and assign their benefits to Columbia, would be less than $17 per month, eliminating the Plus amount would effectively eliminate their Columbia bills. Yet, if the additional CAP costs based on the DPW directive are passed onto non-CAP residential customers rather than to CAP customers through the CAP-Plus program, as PCOC suggests, non-CAP residential customers will pay an extra $16.08 per year.

[25] CAP costs are paid by non-participants through a volumetric charge. Therefore, high users pay more than the average while low users pay less.

OCA St. 3-R at 15. As also already explained, the lowest income households that receive LIHEAP will be better off under the CAP-Plus than under the original CAP design.

Based on the foregoing, the OCA submits that PCOC's assertion that Columbia's CAP-Plus program is unsound public policy must be rejected.

4. <u>One Modification To The CAP-Plus Program Should Be Adopted.</u>

While the OCA fully supports the Columbia CAP-Plus program, since its original design was approved by the Commission last year, the OCA has identified a possible change regarding the amount of LIHEAP that will be allocated to Pennsylvania that should be considered in the CAP-Plus program design. As explained, the CAP-Plus design uses the total LIHEAP receipts received by Columbia in the preceding LIHEAP program year to determine the Plus amount. If the federal allocation of LIHEAP funds to Pennsylvania remains constant from year to year, this approach works well. OCA St. 3-R at 12. The proposed federal budget for next fiscal year, however, proposes to cut the LIHEAP appropriation by nearly 50%, which will greatly reduce the LIHEAP funding provided to the states, including Pennsylvania. Basing the Plus amount on federal LIHEAP funding from a prior year when there could be a substantial reduction in the LIHEAP appropriation could result in a Plus amount that is too high.

In light of the new potential for large changes in the LIHEAP appropriations, OCA witness Colton recommended that an additional feature be added to the CAP-Plus program design. OCA witness Colton explained his proposal:

> The Company needs to be given both the opportunity, and the responsibility, to adjust the "plus" amount at the request of the Commission, the Bureau of Consumer Services, the Office of Consumer Advocate, or other interested stakeholders, in the event that its LIHEAP receipts are expected to be out of line with its previous experience.

> This proposal should operate in either direction. The President's recommendation to cut LIHEAP in half simply identified the issue that actual LIHEAP appropriations may differ substantially in some years. The Company's process for calculating the "plus" amount for a CAP-Plus program should have an "escape clause" to allow for adjustments if significant LIHEAP budget changes are experienced. Note that my proposal is not simply to "refine" the "plus" amount once the actual LIHEAP appropriation is known.
> My proposal is limited to paradigm-shifting changes in the LIHEAP allocation to Pennsylvania. I allow for various stakeholders to determine how much of a change in LIHEAP appropriations is "paradigm shifting" and to allow the PUC to operationally define that term in case-specific deliberations.

OCA St. 3-R at 13.

The OCA submits that Mr. Colton's recommendation should be adopted to address major shifts in the LIHEAP appropriation at the federal level.

5. Conclusion

The OCA supports Customer Assistance Programs that help to improve the affordability of utility bills for low income, payment troubled residential customers while maintaining the reasonableness of the cost impact of the program on other residential customers. The OCA submits that Columbia's CAP-Plus program achieves these important goals and properly integrates the federal LIHEAP program with this ratepayer-funded program in a manner consistent with federal law. Through the CAP-Plus program, the ratepayer-funded program and the federally-funded program are closely coordinated and ensure that the program efforts are "mutually reinforcing" in pursuing the goal of affordable energy service as required by federal law. OCA St. 3-R at 3-4. The CAP-Plus program efficiently meets these concerns and avoids the waste of scarce resources. The criticisms of Columbia's CAP-Plus program by PCOC are not soundly based and must be rejected.

Moreover, PCOC's proposal to follow the DPW directive without addressing the impact of the significant change in DPW policy affecting program design cannot be supported. It is neither reasonable, nor required, to impose additional costs on non-CAP customers in light of the DPW directive to apply LIHEAP grants to asked to pay amounts. Columbia's prior CAP program (pre-DPW directive), which was supported by the OCA and operated successfully for nearly 20 years, provided affordable bills to CAP participants and helped to contain the cost of this initiative by, *inter alia*, applying LIHEAP funds to the CAP shortfall. DPW's new policy – which is directly contrary to the policy adopted by other comparable programs in the Nation – changes this fundamental program element and results in non-participating customers being required to pay even more to support the CAP programs. DPW's new policy directive regarding the integration of the LIHEAP grant with the ratepayer-funded program necessitated the implementation of the Columbia CAP-Plus program to restore the balance that has allowed these programs to grow and succeed over the last two decades. The Commission should again affirm Columbia's CAP-Plus program and reject any attempt to impose additional burdens on residential customers.

IV. CONCLUSION

For the reasons set forth above, the Office of Consumer Advocate respectfully requests that the Commission direct Columbia to continue with its current residential rate design and continue charging a $12.25 monthly customer charge. In addition, the OCA submits that the Commission should reject PCOC's challenge to Columbia's existing CAP-Plus program.

Further, the OCA submits that the Joint Petition for Partial Settlement filed with the Commission on June 27, 2011 reflects a reasonable resolution of the issues addressed therein, is not opposed by any of the active parties and should be approved by the Commission.

Respectfully Submitted,

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Dated: June 27, 2011
144942

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins

QUESTION 27:

Referring to Watkins testimony, Page 16, Lines 1 through 12:

a. Why does Watkins not include the cost of transformers in his direct customer cost analysis since the cost of a transformer is necessary for customers?
b. Since for rural electric cooperatives a separate transformer is usually necessary in order for every consumer to receive electricity, does Watkins not agree that the cost of the transformer should be included in his direct customer cost analysis? Why or why not?
c. Please provide the customer charges for both the residential and small commercial classes that include the direct expenses with the inclusion of a transformer.
d. Marginal costs have been discussed as the proper approach for pricing service and it is further discussed that the customer charge should be based upon direct costs. Please calculate what the direct costs would be for the customer charge by using current cost, using your direct customer cost analysis technique, with and without transformer costs included.
e. Does Watkins believe in losses on the customer charge and making it up on volume sales? Please explain this response.

RESPONSE:

a. Transformers are not considered as a customer-related cost.

b. Please see response to 26 (a).

c. Mr. Watkins has not conducted such an analysis. Moreover, it is Mr. Watkins opinion that to do so would be incorrect.

d. Mr. Watkins has not conducted the requested analysis.

WITNESS RESPONSIBLE:
Glenn Watkins

e. Customer charges/revenues are only one component of a consumer's electric bill. Because of the joint-use of an electric utility's facilities, it is generally impractical (if not impossible) to accurately determine if a utility increases "losses" from a particular customer, let alone a single component within a customer's bill.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 28:

Referring to Watkins testimony, Page 16. Lines 14-21 wherein he states "that customers do not subscribe to Owen's services simply to be "connected," overhead and indirect costs are most appropriately recovered through energy charges"

a. Does Watkins believe that in a business where the price of a good is determined, would not overhead be included in the price determination?
b. If a company does not recover all of its fixed costs in the short run, would Watkins agree that a company will likely go out of business before it reaches the theoretical "long run"?
c. Would Watkins agree that the price of the good must rise to cover all costs associated with running the business in an efficient manner?

RESPONSE:

a. Yes.

b. Yes.

c. No.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins
Page 1 of 1

QUESTION 29:

Referring to Watkins testimony, Page 17, Lines 4 through 30; page 18, lines 1 through 27:

a. Does Watkins believe that Owen is reaching the price point where the price will become elastic?
b. Does Watkins believe that with an aggressive educational plan by Owen, TOD rates will become more popular? Why or why not?
c. Please define what an "instant case" is as referred to throughout Watkins' testimony. Please document where Owen refers to this case as an "instant case" in the original filing.

RESPONSE:

a. No.

b. In all likelihood, no. Residential time-of-use pricing has been promoted and employed with very limited success throughout the United States since the 1970's.

c. "Instant case" refers to this docket.

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF
OWEN ELECTRIC COOPERATIVE, INC.
CASE NO. 2011-00037

WITNESS RESPONSIBLE:
Glenn Watkins, Counsel
Page 1 of 1

QUESTION 30:

Please provides copies of all contracts between the Attorney General's office and that of Watkins, including any contract with him personally, or any consulting firm for which he owns any interest and/or is employed on a part time or full time basis. Additionally, please supply information relating to all engagements that Watkins has worked for the Attorney General's office in the last five years, including the nature of the engagement, the dates of service of each engagement, and the compensation Watkins received for his services for each engagement.

RESPONSE:

Objection. The materials sought are subject to the work-product privilege, and / or the attorney-client privilege. Moreover, the Attorney General would be put at an unfair competitive disadvantage if he has to divulge this information as it would provide other experts and/or consultants with the Attorney General's contractual pricing for services.

Without waiving this objection, counsel refers Owen to Attachment 1 to this question which provides a list of the cases for which Mr. Watkins has provided testimony on behalf of the Commonwealth of Kentucky, Office of Attorney General.

WATKIN'S RESPONSE TO OWEN
QUESTION 30

ATTACHMENT 1

EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
1985	SAVANNAH ELECT. & PWR CO.	GA. PSC	3523U	SALES FORECAST, RATE DESIGN ISSUES
1990	CENTRAL MAINE PWR CO.	ME. PUC	89-68	MARGINAL COST OF SERVICE
1990	COMMONWEALTH GAS SERVICES (Columbia Gas)	VA. SCC	PUE900034	CLASS COST OF SERVICE
1990	WARNER FRUEHAUF	U.S. BANKRUPTCY CT.	n/a	VALUE OF STOCK, COST OF CAPITAL
1991	W. VA. WATER	WVA PSC	91-140-W-42T	RATE DESIGN
1992	S.C. WORKERS COMPENSATION	SC DEPT OF INSUR	92-034	INTERNAL RATE OF RETURN
1992	GRASS v. ATLAS PLUMBING, et.al.	RICHMOND CIRCUT CT	n/a	DAMAGES, BREACH OF COVENANT NOT TO COMPETE (PROFFERED TEST)
1992	VIRGINIA NATURAL GAS	VA SCC	PUE920031	JURISDICTIONAL & CLASS COST OF SERVICE
1992	ALLSTATE INSURANCE COMPANY (DIRECT)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1992	ALLSTATE INSURANCE COMPANY (REBUTTAL)	N.J. DEPT OF INSUR	INS 06174-92	COST ALLOCATIONS, PROFITABILITY
1993	MOUNTAIN FORD v FORD MOTOR COMPANY	FEDERAL DISTRICT CT	n/a	VEHICLE ALLOCATIONS, INVENTORY LEVELS, INCREMENTAL PROFIT, & DAMAGES
1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	DIRECT: CLASS COST ALLOCATIONS
1993	SOUTH WEST GAS CO.	AZ. CORP COMM	U-1551-92-253	SURREBUTTAL: CLASS COST ALLOCATIONS
1993	POTOMAC EDISON CO.	VA. SCC	PUE930033	COST ALLOCATIONS,RATE DESIGN
1995	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1995	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR95040165	COST ALLOCATIONS,RATE DESIGN
1995	PIEDMONT NATURAL GAS COMPANY	S.C. P.S.C.	95-715-G	COST ALLOCATIONS,RATE DESIGN,WEATHER NORMALIZATION
1995	CYCLE WORLD v. HONDA MOTOR CO.	VA. DMV	None	MARKET PERFORMANCE, FINANCIAL IMPACT OF NEW DEALER
1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1996	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE950003	JURISDICTIONAL ALLOCATIONS
1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	COST ALLOCATIONS,RATE DESIGN
1996	ELIZABETHTOWN WATER CO.	N.J. B.P.U.	WR95110557	SURREBUTTAL COST ALLOCATIONS,RATE DESIGN
1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	CLASS COST OF SERVICE
1996	VIRGINIA LIABILITY INSURANCE COMPETITION	VA. SCC	INS960164	COST ALLOCATIONS, INSURANCE PROFITABILITY
1996	SOUTH JERSEY GAS CO.	N.J. B.P.U.	GR96010032	REBUTTAL - CLASS COST OF SERVICE
1996	HOUSE BILL # 1513	VA. GEN'L ASSEMBLY	N/A	WATER / WASTEWATER CONNECTION FEES
1997	NISSAN v. CRUMPLER NISSAN	VA. DMV	None	MARKET DETERMINATION & PERFORMANCE
1997	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (REBUTTAL)	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	PHILADELPHIA SUBURBAN WATER CO. (SURREBUTTA	PA. PUC	R-00973952	COST ALLOCATIONS,RATE DESIGN,RATE DISCOUNTS
1997	VIRGINIA AMERICAN WATER CO.	VA. SCC	PUE970523	JURISDICTIONAL/CLASS ALLOCATIONS
1998	VIRGINIA ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	NEW JERSEY AMERICAN WATER COMPANY	N.J. B.P.U.	WR98010015	CLASS COST OF SERVICE,RATE DESIGN, REVENUES
1998	AMERICAN ELECTRIC POWER COMPANY	VA. SCC	PUE960296	CLASS COST OF SERVICE and TIME DIFFERENTIATED FUEL COSTS
1998	FREEMAN WRONGFUL DEATH	FfEDERAL DISTRICT CT.		LOST INCOME, WORK EXPECTANCY
1998	EASTERN MAINE ELECTRIC COOPERATIVE	MAINE PUC	98-596	REVENUE REQUIREMENT
1998	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
1999	CREDIT LIFE & A&H LEGISLATION	VA. GEN'L ASSEMBLY	N/A	COST ALLOCATIONS, INSURANCE PROFITABILITY
1999	MILLER VOLKSWAGEN v. VOLKSWAGEN oF AMERICA	VA. DMV	None	VEHICLE ALLOCATIONS/CSI
1999	COLUMBIA GAS of VIRGINIA	VA. SCC	PUE980287	RATE STRUCTURE
1999	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS990165	WORKERS COMPENSATION RATES
1999	ROANOKE GAS	VA. SCC	PUE980626	Rate Design/ Weather Norm
2000	PERSON-SMITH v. DOMINION REALITY	RICHMOND CIRCUIT	n/a	LOST INCOME
2000	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2000	UNITED CITIES GAS	VA. SCC		Cost Allocations/ Rate Design
2001	VERMONT WORKERS COMPENSATION RATE CASE	VT. INSURANCE COMM.	n/a	WORKERS COMPENSATION RATES
2001	SERRA CHEVROLET v. GENERAL MOTORS CORP.	ALABAMA CIRCUIT CT.	98-2089	ECONOMIC DAMAGES
2001	VIRGINIA POWER ELECTRIC RESTRUCTURING	VA. SCC	PUE000584	RATE Design (UNBUNDLING)
2001	AMERICAN ELECTRIC POWER RESTRUCTURING	VA. SCC	PUE010011	RATE Design (UNBUNDLING)
2001	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS010190	WORKERS COMPENSATION RATES
2002	PHILADELPHIA SUBURBAN WATER CO. (DIRECT)	PA. PUC	R00016750	COST ALLOCATIONS AND RATE DESIGN
2002	HAROLD MORRIS PERSONAL INJURY	FED. DIST CT (RICHMOND)	n/a	LOST WAGES
2002	PIEDMONT NATURAL GAS	S.C. PSC	2002-63-G	REVENUE RQMT, COST OF CAPITAL
2002	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2002-00375	JURISDICTIONAL/CLASS ALLOCATIONS
2002	ROANOKE GAS COMPANY	VA. SCC	PUE-2002-00373	WEATHER NORMALIZATION RIDER
2002	SOUTH CAROLINA ELECTRIC & GAS (ELECTRIC)	S.C. PSC	2002-223-E	REVENUE RQMT.

EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2003	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2003-00157	WORKERS COMPENSATION RATES
2003	CREDIT LIFE/AH RATE FILING	VA. SCC		PRIMA FACIA RATES, LEVEL OF COMPETITION
2003	ROANOKE GAS	VA. SCC	PUE-2003-00425	WEATHER NORMALIZATION ADJUSTMENT RIDER
2003	SOUTHWESTERN VIRGINIA GAS CO.	VA. SCC	PUE-2003-00426	WEATHER NORMALIZATION ADJUSTMENT RIDER
2004	SOUTH CAROLINA PIPELINE COMPANY	S.C. PSC	2004-6-G	COST OF GAS AND INTERUPT. SALES PROGRAM
2004	VIRGINIA AMERICAN WATER COMPANY	VA. SCC	PUE-2003-00539	JURISDICTIONAL/CLASS ALLOCATIONS
2004	SCE&G FUEL CONTRACT	S.C. PSC	2004-126-E	GAS CONTRACT FOR COMBINED CYCLE PLANT
2004	WASHINGTON GAS LIGHT	VA. SCC	PUE-2003-00603	RATE DESIGN/ WNA RIDER
2004	ATMOS ENERGY	VA. SCC	PUE-2003-00507	RATE DESIGN/ WNA RIDER
2004	SCE&G RATE CASE (ELECTRIC)	S.C. PSC	2004-178-E	COST OF CAPITAL/ REV RQMT.
2004	MEDICAL MALPRACTICE LEGISLATION	VA. GENERAL ASSEMBLY	N/A	INDUSTRY RESTRUTURE/ PROFITABILITY
2004	ATLAS HONDA v. HONDA MOTOR CO.	VA. DMV	None	NEW DEALER PROTEST
2004	NCCI (WORKERS COMPENSATION INSURANCE)	VA. SCC	INS-2004-00124	WORKERS COMPENSATION RATES
2004	NATIONAL FUEL GAS DISTRIBUTION	PA. PUC	R00049656	COST ALLOCATIONS/ RATE DESIGN
2005	WASHINGTON GAS LIGHT	VA SCC	PUE-2005-00010	WEATHER NORMALIZATION ADJUSTMENT RIDER
2005	Serra Chevrolet	US Federal Ct.	CV-01-P-2682-S	Dealer incremental profits and costs
2005	NEWTOWN ARTESIAN WATER	PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	CITY OF BETHLEHEM WATER RATE CASE	PA. PUC		REV. RQMT./ RATE STRUCTURE
2005	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2005-00159	WORKERS COMPENSATION RATES
2005	Virginia Natural Gas	VA SCC	PUE-2005-00057	Revenue Requirement/ Alt. Regulation Plan
2006	Olathe Hyundai v. Hyundai Motors of America	KS DMV	None	Dealer impact analysis
2006	Virginia Credit Life & A&H Prima Facia Rates	VA SCC	INS-2006-00013	Market Structure
2006	Columbia Gas of Virginia	VA SCC	PUE-2005-00098	Revenue Requirements/ Alt. Regulation Plan
2006	PPL Gas	PA. PUC	R-00061398	COST ALLOCATIONS/ RATE DESIGN
2006	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2006-00197	WORKERS COMPENSATION RATES
2007	Level of Private Pass. Auto Competition	Ma. Dept of Insur	N/A	Private Pass Auto level of competition
2007	WASHINGTON GAS LIGHT	VA SCC	PUE-2006-00059	Cost Allocations/ Rate Design/ Alt Regulation Plan
2007	Valley Energy	PA. PUC	R-00072349	Cost of Capital/Rate Design
2007	Wellsboro Electric	PA. PUC	R-00072350	Cost of Capital/Rate Design
2007	Citizens' Electric Of Lewisburg, Pa	PA. PUC	R-00072348	Cost of Capital/Rate Design
2007	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2007-00224	WORKERS COMPENSATION RATES
2007	Georgia Power	Ga.PSC	25060-U	Cost Allocations/Rate Design
2008	Columbia Gas of Pennsylvania	PA. PUC	R-2008-2011621	COST ALLOCATIONS/ RATE DESIGN
2008	Greenway Toll Road Investigation	VA. GENERAL ASSEMBLY	N/A	Affiliate Transactions
2008	Puget Sound Energy (Electric)	Wa. UTC	UE-072300	Cost Allocations/Rate Design
2008	Puget Sound Energy (Gas)	Wa. UTC	UE-072301	Cost Allocations/Rate Design
2008	Blue Grass Electric Cooperative	Ky PSC	2008-00011	Cost Allocations/Rate Design
2008	Columbia Gas of Ohio	OH PUC	08-72-GA-AIR, et. al	Cost Allocations/Rate Design
2008	Virginia Natural Gas	Va SCC	PUE-2008-00060	Natl Gas Conservation/ Revenue Decoupling
2008	Equitable Natural Gas	PA. PUC	R-2008-2029325	Cost Allocations/Rate Design/ Discounted Rates
2008	LG&E (Electric)	Ky PSC	2008-000252	Cost Allocations/Rate Design/ Weather Normalization
2008	LG&E (Natural Gas)	Ky PSC	2008-000252	Cost Allocations/Rate Design
2008	Kentucky Utilities	Ky PSC	2008-00251	Cost Allocations/Rate Design/ Weather Normalization
2008	Pike County Natural Gas	PA. PUC	R-2008-2046520	Cost Allocations/Rate Design
2008	Pike County Electric	PA. PUC	R-2008-2046518	Cost Allocations/Rate Design
2008	Newtown Artesian Water	PA. PUC	R-2008-2042293	Revenue Requirement
2009	Leesburg Water & Sewer	Va. Circuit Ct.	Civil Action 42736	Revenue Requirement/ Excess Rates
2009	Central Penn Gas, Inc.	PA. PUC	R-02008-2079675	Cost Allocation/Rate Design
2009	Penn Natural Gas, Inc.	PA. PUC	R-2008-2079660	Cost Allocation/Rate Design
2009	Credit Life/ A&H ratemaking	Va. SCC	n/a	Market Structure and Availability
2009	Fairfax County v. City of Falls Church Virginia	Fairfax Circuit Ct. (Va.)	CL-2008-16114	Water Revenue Requirement
2009	Avista Utilities (Electric)	Wa. UTC	UE-090134	Electric rate Design
2009	Avista Utilities (Gas)	Wa. UTC	UE-090135	Gas Rate design
2009	Columbia Gas of Kentuky	Ky PSC	2009-00141	Cost Allocations/Rate Design
2009	NCCI (Workers Compensation Rates)	VA SCC	INS-2009-00142	Workers Compensation Rates
2009	Duke Energy of Kentucky (Gas)	Ky. PSC	2009-00202	Rate Design

**EXPERT TESTIMONY
PROVIDED BY
GLENN A. WATKINS**

YEAR	CASE NAME	JURISDICTION	DOCKET NO.	SUBJECT OF TESTIMONY
2009	Duke Energy Carolinas (Electric)	NC UC	E-7 Sub 909	Cost Allocations/Rate Design
2009	PacifiCorp	Wa. UTC	UE-090205	Rate Design/Low Income
2009	Puget Sound Energy (Electric)	Wa. UTC	UE-090704	Cost Allocations/Rate Design
2009	Puget Sound Energy (Gas)	Wa. UTC	UG-090705	Cost Allocations/Rate Design
2009	United Water of Pennsylvania	PA PUC	2009-212287	Cost Allocations/Rate Design
2010	Aqua Virginia, Inc.	VA SCC	PUE-2009-00059	Rate Design
2010	Kentucky Utilities	Ky PSC	2009-00548	Cost Allocations/Rate Design/ Weather Normalization
2010	LG&E (Electric)	Ky PSC	2009-00549	Cost Allocations/Rate Design
2010	LG&E (Natural Gas)	Ky PSC	2009-00549	Cost Allocations/Rate Design/ Weather Normalization
2010	Philadelphia Gas Works	PA PUC	2009-2139884	Cost Allocations/Rate Design
2010	Columbia Gas of Pennsylvania	PA PUC	2009-2149262	Cost Allocations/Rate Design
2010	PPL Electric Company	PA PUC	2010-2161694	Cost Allocations/Rate Design
2010	York Water Company	PA PUC	2010-2157140	Cost Allocations/Rate Design
2010	Valley Energy, Inc.	PA PUC	2010-2174470	Cost of Capital/Revenue Requirement/Rate Design
2010	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	INS-2010-00126	WORKERS COMPENSATION RATES
2010	Columbia Gas of Virginia	VA SCC	PUE-2010-00017	Cost of Capital/Revenue Requirement/Rate Design
2010	Georgia Power Company	GA PSC	Docket No. 31958	Cost Allocations/Rate Design
2010	City of Lancaster, Bureau of Water	PA PUC	R-2010-2179103	Cost of Capital
2011	Columbia Gas of Pennsylvania	PA PUC	R-2010-2215623	Cost Allocations/Rate Design
2011	Owen Electric Cooperative	KY PSC	PUE-2011-00037	Rate Design
2011	Virginia Natural Gas	VA SCC	PUE-2010-00142	Pipeline Prudency/Cost Allocations/Rate Design
2011	United Water of Pennsylvania	PA PUC	2011-2232985	Cost Allocations/Rate Design
2011	PPL Electric Company (Remand)	PA PUC	2010-2161694	Negotiated Industrial Rate
2011	NCCI (WORKERS COMPENSATION INSURANCE)	VA SCC	2011-00163	WORKERS COMPENSATION RATES
2011	Artesian Water Company	DE PSC	11-207	Cost Allocations/Rate Design

**Note: Does not include Expert Reports submitted to Courts or Regulatory agencies in which cases that settled prior to testimony.
Testimony prior to 2003 may be incomplete.**