BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
MAUI ELECTRIC COMPANY, LIMITED	)	Docket No. 2006-0387
	)	
For Approval of Rate Increases and Revised Rate Schedule and Rules	)	
	)	

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MECO
2007 TEST YEAR

DIRECT TESTIMONIES AND EXHIBITS

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February 23, 2007

MECO T-17
DOCKET NO. 2006-0387

TESTIMONY OF
TAYNE S. Y. SEKIMURA

FINANCIAL VICE PRESIDENT

MAUI ELECTRIC COMPANY, LTD.

Subject: Rate of Return on Rate Base

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and I am the Financial Vice President of Maui Electric Company, Limited ("MECO" or the "Company"). My business address is 900 Richards Street, Honolulu, Hawaii, 96813. MECO-1700 provides my educational background and work experience.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to recommend a fair and reasonable rate of return on the Company's rate base for test year 2007. I will explain the basis for MECO's capital structure and the derivation of its composite cost of capital. I will provide details supporting the Company's sources, proportions, and costs of investor funds. Further, my testimony will discuss how the Company's Energy Cost Adjustment Clause ("ECAC") addresses the financial factors that Act 162[1] mandates and recommends to the Commission a rate of return on common equity, based on the testimony of Dr. Roger Morin, Professor of Finance, Georgia State University, College of Business, who has developed an estimate of the return on common equity he deems to be fair and reasonable.

Another purpose of my testimony is to explain why the Company does not believe that it is necessary to conduct a comprehensive analysis for this docket of the impact of Hawaiian Electric Industries, Inc. ("HEI") on MECO's cost of capital [in regard to Decision and Order ("D&O") No. 15225[2]].

In addition, my testimony includes an estimate of the savings to customers resulting from the use of special purpose revenue bond financing, as required by Hawaii law.[3]

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[1] Section 269-16 (g), Hawaii Revised Statutes.
[2] Decision and Order No. 15225, filed in Docket No. 7591 on December 10, 1996.
[3] Hawaii Revised Statues ("H.R.S.") Section 39-A-208(b).

RATE OF RETURN ON RATE BASE

Q. What is the purpose of the rate of return on rate base?

A. The rate of return on rate base is used to calculate the revenues necessary to fairly compensate investors for the use of their money invested in assets that are used or useful in providing service to the utility's customers.

Q. What is the fair rate of return on rate base for test year 2007?

A. A fair rate of return on rate base for MECO for test year 2007 is 8.98% as calculated on MECO-1701.

Q. Why is 8.98% a fair return on rate base for test year 2007?

A. A rate of return on rate base of 8.98% for MECO is fair because it satisfies the three requirements for fairness established by the Bluefield and Hope cases.

The requirements for "fairness," as set forth in Bluefield Water Works & Improvements Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and in Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944), are that the return should:

1) Be commensurate with returns on investments in other enterprises having corresponding risks and uncertainties;
2) Provide a return sufficient to cover the capital costs of the business, including service on the debt and dividends on the stock; and
3) Provide a return sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and capital-attracting ability.

A return on rate base of 8.98% for MECO for test year 2007 will satisfy these requirements for fairness.

Q. Are these criteria consistent with the criteria used by the Commission in prior rate cases?

A. Yes. These criteria were used by the Commission in numerous MECO rate case decisions including Decision and Order ("D&O") No. 16922 (Docket No. 97-0346, MECO 1999 Test Year), D&O No. 16134 (Docket No. 96-0040, MECO 1997 Test Year), and D&O No. 15544 (Docket No. 94-0345, MECO 1996 Test Year), as well as numerous Hawaiian Electric Company, Inc. ("HECO") and Hawaii Electric Light Company, Inc. ("HELCO") rate case decisions.

Q. How should a fair return on rate base be developed in these proceedings?

A. A percentage return on rate base that is at least equal to the Company's composite cost of capital would be a fair rate of return in this docket.

Q. Why must a fair rate of return on rate base be at least equal to MECO's composite cost of capital?

A. The composite cost of capital represents the carrying cost of the money received from investors to finance the rate base. In order to adequately compensate those who have invested in the Company, MECO needs to be allowed a reasonable opportunity to earn at least its composite cost of capital.

Further, a rate of return on rate base at least equal to the Company's composite cost of capital would satisfy the three requirements of a fair return, provided that the Company is given a realistic opportunity to actually earn the return. A finding by the Commission of a return on rate base at least equal to the Company's composite cost of capital would allow the Company to cover the capital costs of the business; it would provide a return on investment commensurate with returns on other investments having corresponding risks; and it would provide assurances to the financial community of the Company's financial integrity (or financial strength).

COMPOSITE COST OF CAPITAL

Q. What is the composite cost of capital?

A. The composite cost of capital is the weighted average cost of short-term debt, long-term debt, hybrid securities, preferred stock, and common equity of the Company. It represents the carrying cost of the money received from investors to finance the rate base.

Q. How is the composite cost of capital calculated?

A. The composite cost of capital is calculated by summing the weighted effective costs of each element of the capital structure. The capital structure is made up of the short-term debt, long-term debt, hybrid securities, preferred stock, and common equity of the Company. The overall cost of each of the elements is calculated taking into account such items as issuance costs to come up with an "effective" cost for each element. The "effective" cost of each element of the capital structure is "weighted" in proportion to its percentage in the capital structure to come up with a weighted effective cost.

Q. Has the same method been used by MECO, HECO, and HELCO in prior rate cases?

A. Yes. This method was used in Docket No. 97-0346 (MECO 1999 Test Year), Docket No. 96-0040 (MECO 1997 Test Year), and Docket No. 94-0345 (MECO 1996 Test Year) as well as numerous HECO and HELCO rate cases.

Q. What is the Company's average estimated composite cost of capital for test year 2007?

A. The Company's estimated average composite cost of capital is 8.98% for test year 2007, as shown on MECO-1701.

GOALS IN FINANCING

Q. What are the Company's overall goals in determining its financing?

A. In determining its financing, the Company strives to balance:

1) obtaining funds at the lowest reasonable cost, and

2) preserving the financial strength of the Company.

Obtaining Funds at the Lowest Reasonable Cost

Q. How does the Company obtain funds at the lowest reasonable cost?

A. Low cost funds are obtained by: 1) issuing securities that are relatively low risk to investors and 2) minimizing the Company's business and financial risks, to the extent the Company can control those risks and it is appropriate to do so in the context of the Company's overall business plan.

Q. What securities do investors consider to be relatively low risk?

A. Investors consider debt issuances to be relatively low risk securities since there is assurance that the investor will be paid a stated rate at predetermined periods before other types of investors are able to get disbursements from the Company. Debt is usually the least costly source of funds for the Company.

Q. Why doesn't the Company obtain all of its financing from debt?

A. Although debt is low risk to investors, it is relatively high risk to the Company. Higher proportions of debt would mean more fixed obligations and higher risk of default on debt covenants. This would increase the cost of the debt since lenders would need more compensation for taking more risk if there are more fixed obligations. Also, investors will not lend money to companies with no equity support. Some level of equity support is necessary in order to access the debt market. Therefore, the Company must balance the relatively lower cost debt with relatively higher cost equity in determining its capital structure.

Maintaining Financial Strength

Q. Why is it important for the Company to maintain its financial strength?

A. Investors are very sensitive to financial strength considerations when they decide where to invest their money. If MECO's financial strength is not maintained, more risk averse investors will invest their money elsewhere. This, in turn, will

have negative implications for MECO's customers because it will reduce the demand for the Company's securities and will increase its cost of capital. Further, under adverse market conditions, it may be difficult to attract capital. It is imperative from a customer standpoint, therefore, that MECO at least maintain its current financial strength.

Q. How is financial strength measured?

A. One of the principal measures of a company's financial strength is its credit rating. Credit ratings are issued by independent rating agencies, such as Standard and Poor's ("S&P") or Moody's Investors Services ("Moody's"). A credit rating is an impartial opinion of the general creditworthiness of a company (issuer credit rating) or the creditworthiness of a company with respect to a particular security (issue-specific credit rating). Credit rating agencies evaluate the investment risk in commercial paper, secured and unsecured debt, hybrid securities, and preferred stock. The rating for each security reflects the investment risk in that security, given the rating agency's overall evaluation of the financial condition of the company and the particular characteristics of the individual security.

Q. Why is it important for the Company to maintain good credit ratings?

A. It is important to maintain good credit ratings for the following reasons:

1) Maintaining good credit ratings helps to minimize electric rates by lowering the cost of capital to the Company. A credit rating is a measure of credit risk. All other things being equal, a company with less risk will have a lower cost of capital.

2) Maintaining good credit ratings gives the Company the ability to consistently attract new capital on reasonable terms, whatever the current state of the financial markets. The Company raises its capital in a competitive market. The supply and demand for investors' funds change as

economic conditions change. Under ideal conditions, financing is available for most companies. Under adverse economic conditions, however, companies with weaker credit ratings may find it difficult, if not impossible, to raise new capital. A good credit rating assures investors that the company is financially sound, so that they will continue to have an interest in purchasing the company's securities. For example, many companies (including MECO) restrict their investment portfolios to investments in companies that have ratings that are at least "investment grade."[4] Continuous access to capital markets is critical for a capital-intensive company such as MECO that has an obligation to provide utility services.

Q. How do rating agencies determine credit ratings?

A. In order to determine a company's credit rating, the rating agencies evaluate a wide range of qualitative and quantitative factors that affect the company's credit quality. This assessment considers both the business risks and the financial risks of the company.

Q. How are MECO's credit ratings measured?

A. MECO's credit ratings from S&P and Moody's are based on the collective financial strength of HECO, MECO, and HELCO (together, the "Companies"):

Long-term debt (unsecured): Because HECO guarantees the payment of principal and interest on both MECO's and HELCO's unsecured long-term debt, the rating agencies evaluate the consolidated HECO to get a credit rating for all of the Companies' unsecured long-term debt.

Preferred Stock: HECO guarantees the obligations of MECO and HELCO, but only if HECO has already met its own preferred stock obligations. The rating

[4] Standard & Poor's rating of BBB- or higher or Moody's rating of Baa3 or higher. See S&P "Rating Definitions" in Docket No. 04-0113 (HECO 2005 TY Rate Case), Exhibit HECO-2108, pages 1 to 4 filed on November 12, 2004.

agencies recognized this "junior position" of the subsidiary preferreds in each of their last sales (MECO's Series H and HELCO's Series G). Therefore, all subsidiary preferreds are treated as one notch lower in credit quality than HECO's preferred stock.

Hybrid Securities: Because HECO guarantees the obligations of MECO and HELCO, the rating agencies evaluate the consolidated HECO to get a credit rating for all of the Companies' hybrids.

Q. If to some degree, MECO trades on HECO's consolidated credit rating, why is it important for MECO to also have a sound capital structure?

A. In order to minimize intercompany subsidization, to the extent it is practical, which would occur if the credit risks of the Companies were significantly different from each other, MECO seeks to maintain its own financial strength, as an individual company, in accordance with the rating agency guidelines and HECO's credit ratings.

Business Risks

Q. What things do the rating agencies consider in assessing business risk?

A. Business risk considerations cited in Standard & Poor's article, "Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers" dated September 14, 2006 (provided in Exhibit MECO -1708), include five basic characteristics: regulation, markets, operations, competitiveness, and management.

Q. What business risks does the Company face?

A. The Company faces numerous business risks.[5] I will discuss several business risks underlying each of the five basic characteristics which help to define MECO's business profile.

1. REGULATION

Regulation is a critical aspect that underlies a utility's creditworthiness, and decisions by the regulators can profoundly affect financial performance.

1) Energy Cost Adjustment Clause ("ECAC")

For many years, the Company has been allowed the use of an ECAC. The ECAC is an automatic adjustment provision in MECO's rate schedules that allows MECO to automatically increase or decrease rates to reflect changes in the Company's costs of fuel and purchased energy above or below the expense levels included in base charges, without a rate proceeding. In 2006, new legislation[6] required that the Commission evaluate the continued use of the ECAC in each rate proceeding in which it was requested by the Company. Our investors are clearly concerned by the legislative action. I will discuss the financial implications of this legislation in greater detail later in my testimony.

2) Renewable Portfolio Standards

The Renewable Portfolio Standards law ("RPS"), as amended by the Legislature in 2004 and in 2006, requires MECO (in aggregate with HECO and HELCO) to obtain certain percentages of sales from renewable electrical energy resources ("RE").[7] Renewable electrical energy resources

[5] See "Forward-Looking Statements" from HEI and HECO Form 10-Q for the quarterly period ended September 30, 2006 filed as Exhibit MECO-1709.

[6] Act 162 added a provision in HRS 269-16 reiterating the Commission's discretion to evaluate any automatic fuel rate adjustment clause requested by a utility.

[7] Each electric utility company that sells electricity for consumption in the state shall establish a renewable portfolio standard of: 10% by end of 2010, 15% by end of 2015, and 20% by end of 2020. At

include electrical energy generated using renewable energy sources, and electrical energy savings brought about by renewable displacement technologies (such as solar water heating) or energy efficiency measures. On January 11, 2007, the Commission issued Order No. 23191 in Docket No. 2007-0008 that initiates a proceeding to establish and issue penalties against electric utility companies who fail to meet the RPS. Thus, uncertainties regarding how and if the Company will be able to finance, recover and earn on its investments in renewable energy resources made in order to meet the requirements of the RPS and whether the Company may incur penalties if the requirements of the RPS are not met, increase the Company's financial risk

3) Regulatory Action

The Company has numerous regulatory actions pending before the Commission that will impact the credit rating agency assessment of MECO's regulatory risk. The Company must continue to obtain regulatory rulings that demonstrate regulatory support to at least maintain its current risk level. In an article by S&P dated October 25, 2006[8], S&P states, "credit quality of the industry continues to be defined by the emphasis on core competencies, where risks are more familiar, but can be considerable. These risks include: Major pending regulatory decisions; The approaching end of lengthy rate freezes and industry transition periods in a few states; The need for substantial infrastructure expenditures; and Fuel cost recovery in a high-fuel-price environment." Thus, regulatory decisions that suggest

least fifty percent of the RPS targets shall be met by electrical energy generated using renewable energy as the source.

[8] See S&P article, "Industry Report Card: Few Rating Actions for U.S. Electric, Gas, And Water Utilities In Third Quarter" filed as Exhibit MECO-1710.

the utility will not have regulatory support increase the Company's risk profile, its cost of capital, and ultimately costs to ratepayers.

The timing and adequacy of rate relief (including timely and adequate interim and final rate relief) affect the business risk of the Company and are matters of concern to the rating agencies. In its credit assessment of MECO's parent company, HECO, dated December 21, 2006[9], Moody's stated, "The rating could be downgraded should weaker than expected regulatory support emerge, including the continuation of regulatory lag, which ultimately causes earnings and sustainable cash flow to suffer." Thus, MECO needs the continuing support of the Commission to help maintain its current credit quality standing. Loss of this support could be detrimental in the rating agencies' assessment of the Company's business risk.

2. MARKETS

Assessing market dynamics begins with an economic and demographic evaluation of the service area in which the Company operates.

1) Economy

The Company's operating results are influenced by the volatility of the national and state economy and their impact on the economy of the islands of Maui, Lanai, and Molokai. The visitor industry, the largest component of Hawaii's economy, can fluctuate significantly as a result of terrorist acts across the globe, the geopolitical and war situation, and national and international economic conditions. A large portion of the Company's revenues comes from customers associated with the visitor and construction industries. The impact of having just a few sectors that greatly

[9] See Moody's Investors Service Credit Opinion filed as Exhibit MECO-1711.

influence electric sales growth is that it potentially creates volatility in the Company's revenues.

While the economy appears to have rebounded from the effects of the terrorist attacks, a rise in interest rates may slow down the growth in construction and real estate sales activity. Furthermore, the threats of terror attacks have continued to increase the need for physical security of our facilities and the cost of security and insurance.

2) DSM Programs

The Company recognizes the need for and benefit to Hawaii of reducing Hawaii's dependence on fuel oil and central station generation to meet the electricity needs of our customers.

Since 1996, the Company has implemented energy efficiency demand-side management ("DSM") programs, which have provided incentives to its customers to implement measures that reduce the use of electricity or use electricity more efficiently. Companies incur risks when they encourage customers to reduce the use of their product, which is the case for MECO where DSM programs are designed to influence the utility customer uses of energy to produce desired changes in demand.

On February 13, 2007, the Commission issued D&O 23258 in the Energy Efficiency Docket (Docket No. 05-0069). The Commission ordered that: energy efficiency goals be established, energy efficiency DSM programs be transitioned to a non-utility market structure, utility incentive mechanisms be changed, and other requirements. The Company cannot currently predict the impact of this order.

3. OPERATIONS

When assessing a utility's operations, creditors focus on the Company's ability to provide reliable and safe electric service, the cost to achieve those goals and ability to recover those investments.

1) Capital Investments

The Company is projecting a need for new generation facilities in the next five years due to the increase in its peak forecast and additional investment in the transmission system to improve reliability and to support growth. Construction of generation and transmission facilities may face many challenges due to public sentiment, politics, and permitting requirements. The processes to get all the approvals needed to install these capital additions take many years and therefore put investor funds at risk for extended periods.

Being island environments, Maui, Lanai, and Molokai, each have no inter-ties to other sources of electricity and must build their own resources to meet their individual needs. This increases the significance of making investment in capacity and reliability; and underscores the importance of maintaining access to capital markets to have the financial resources to make necessary capital investments. The Company must be able to construct the facilities and to finance them in order to continue to provide reliable electric service.

2) Purchased Power

The Company expects to purchase more than 15% of its energy from independent power producers ("IPPs"). Purchase power agreements ("PPAs") have been entered into based on the Company's obligations under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and state laws and rules encouraging the purchase of power from non-fossil fuel

producers and qualifying facilities under PURPA, and only with the Commission's determination that costs paid under the contracts were reasonable and approval of the contracts. The Company purchases firm energy from Hawaiian Commercial & Sugar Company ("HC&S"), and as-available energy from Kaheawa Wind Power, LLC. ("KWP") and Makila Hydro, LLC. ("Makila"). See further discussion by Mr. Ribao in MECO T-5. The contracts are obligations that must be paid before shareholders receive any compensation for the use of their funds. MECO investors receive no compensation for the PPAs, but have earnings potential at risk if power purchase costs are not fully recovered in rates (through base rates or the ECAC).

Generally accepted accounting principles[10] determine the financial statement presentation of these and any future contracts. There is uncertainty as to whether there will be any change in accounting impacting existing or new contracts and what impact changes in accounting treatment might have on the investment community's view of those contracts. Credit rating agencies also impute debt on the Company's firm purchased power contract in order to capture the risks associated with these obligations. There is also uncertainty as to whether credit rating agencies may change their assessment of imputed debt.

3) Compliance with Environmental Laws and Regulation

The electric industry faces increasingly stringent environmental laws and regulations which regulate the operation and modification of existing facilities, the construction and operation of new facilities, and the proper

[10] For example: Emerging Issues Task Force Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease" and Financial Accounting Standards Board Interpretation No. 46 "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51"

cleanup and disposal of hazardous waste and toxic substances. The Company is at risk for the direct cost of compliance as well as the economic consequences of any impact on operations.

4) Competitive Bidding Proceeding

This proceeding was to evaluate competitive bidding as a mechanism for acquiring or building new generation capacity in Hawaii. On December 8, 2006, the Commission issued a D&O in this proceeding (D&O No. 23121, Docket No. 03-0372) which included a framework to govern competitive bidding. The Company cannot currently predict the ultimate effect of this proceeding on the ability of the electric utilities to acquire or build additional generating capacity in the future and the associated risks and impact on the Company's cost of capital.

4. COMPETITIVENESS

Although competition in the generation sector in Hawaii has been moderated by the scarcity of generation sites, various permitting processes and lack of interconnection to other electric utilities, MECO faces competition from IPPs and customer self-generation, with or without cogeneration.

1) Bypass Risk -- Distributed Generation ("DG"), Self-Generation

Customers today have more access to alternative energy sources (i.e. self-generation, distributed generation), which are causes for concern for the Company.

The Commission conducted a DG proceeding to determine DG's potential benefits to and impact on Hawaii's electric distribution systems and markets and to develop policies and a framework for DG projects deployed in Hawaii. On January 27, 2006, the Commission issued its D&O

in the DG proceeding (D&O No. 22248, Docket No. 03-0371) indicating that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, DG that is economical and reliable has an opportunity to come to fruition and DG that is not cost-effective does not enter the system. The D&O affirmed the Company's ability to procure and operate DG for utility purposes at utility sites, and also indicated the Commission's desire to promote the development of a competitive market for customer-sited DG.

As these technologies become more economically attractive for customers, the customers may reduce their reliance on, and in some cases may disconnect from, the system, which could put the Company at risk of lost revenues and possible stranded assets.

5. MANAGEMENT

Evaluating management is of paramount importance to the creditors' analysis because management decisions affect all areas of a company's operations and financial health.

1) Commitment to Credit Quality

The Company recognizes that creditors' assessment of management has an impact on the Company's credit rating. Thus management is committed to maintaining credit quality and strives to keep the financial community abreast of the Company's goals, objectives, and strategies at its meetings with the rating agencies.

Q. Have the Company's business risks changed since its last rate case?

A. Yes. Since the Company's last rate case (Docket No. 97-0346, 1999 Test Year), the Company's business risks have increased as it faces more risk and uncertainty as a result of the new legislative Act 162, the utility industry restructuring, the

scrutiny of and by credit rating agencies, and the changes in accounting for pension and OPEB plans, which will be further discussed in my testimony.

Act 162: Energy Cost Adjustment Clause

Q. Has there been any change in investor concerns relating to the Company's fuel and purchased power expenses?

A. Yes. As I mentioned previously, for many years the Company has been allowed the use of an ECAC. The ECAC allows MECO to automatically increase or decrease rates to reflect changes in the Company's costs of fuel and purchased energy above or below the expense levels included in base charges, without a rate proceeding. In 2006, new legislation[11] required that the Commission evaluate the continued use of ECAC in each rate proceeding in which it was requested by the Company. Our investors are clearly concerned by the legislative action. In its credit assessment of MECO's parent company, HECO[12], dated November 22, 2006[13], S&P stated in part:

> "Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to fuel-adjustment mechanism would harm the company's financial condition and detract from its currently satisfactory business profile."

Q. Please briefly describe the Company's existing ECAC mechanism.

A. The ECAC is an automatic adjustment provision in the utility's rate schedules that allows the utility (through the application of the "ECA factor") to automatically increase or decrease charges to reflect the change in the Company's costs of fuel and purchased energy above or below the levels included in the base charges

[11] Act 162 was passed by the State Legislature in the 2006 Legislative Session and signed into law by the Governor on June 2, 2006.
[12] See pages 7-8 of this testimony for discussion of the relationship of MECO and HECO credit ratings.
[13] See S&P Ratings Direct filed as Exhibit MECO-1712.

without a rate proceeding. A rate case proceeding determines the base electricity rates into which are embedded test year levels of fuel prices, payment rates for purchased energy and a test year resource mix. The ECAC mechanism, expressed in cents per kilowatt-hour, allows the Company to recover/return costs due to subsequent changes in (1) fuel and purchased energy costs, (2) the resource mix between utility-owned generation, utility-DG and purchased energy, (3) the resource mix among the utility plants, and (4) the resource mix among purchased energy producers. A rate proceeding also establishes a fixed efficiency factor, or sales heat rate, for the utility central station generation, which provides an incentive to operate the units as efficiently as possible. The ECA factor is filed with the Commission monthly and sets the rate adjustment for the subsequent month. See Mr. Hee's discussion in MECO T-19.

Q. Please describe the investor perspective of the Company's existing ECAC mechanism.

A. MECO's investors view the Company's existing ECAC mechanism very favorably because it significantly reduces the Company's business risks. Dependence on imported fuel oil and the associated fuel price fluctuation are significant risks to the Company. The monthly revenue adjustment for fuel and purchased energy price changes results in timely recovery of fuel oil and purchased energy costs which significantly reduces the business risk profile. Thus, the existing ECAC has a positive credit quality impact.

In its credit assessment of HECO, S&P has in the past cited "an excellent fuel adjustment clause" as strengthening credit quality in part offsetting "reliance on fuel oil", "significant purchased power obligations", and "high prices" which weaken credit quality.

Q. Are there other investor risks associated with fuel and purchased power?

A. Yes. As noted earlier in my testimony, the Company has purchased power obligations which are considered in evaluations of our credit. The reliance on purchased power creates debt-like obligations which are of concern to investors. I discuss the impact of purchased power on our credit quality in greater detail later in my testimony.

Second, the Company is exposed to financial variability due to changes in fuel efficiency. In a rate case proceeding, fuel expense is established based on fuel efficiency factors which are embedded in base electric rates. Mr. Sakuda provides a complete description of the fuel efficiency factor calculation in MECO T-4. When actual heat rates are lower (better) than the heat rates embedded in base rates, fuel expense is lower and returns to shareholders are higher. When actual heat rates are higher (worse) than the heat rates embedded in base rates, fuel expense is higher and returns to shareholders are lower. This gives management incentive to optimize the generation dispatch and to maintain and operate the Company-owned generation to maximize fuel efficiency.

Finally, the Company bears the costs or enjoys the benefits from cost savings resulting from changes in the carrying costs of fuel inventory. The cost of fuel inventory fluctuates as fuel prices fluctuate. Higher fuel prices result in higher inventory cost and higher costs of carrying inventory which reduces returns to shareholders. Conversely, lower fuel prices result in lower inventory cost and lower costs of carrying inventory which contribute to shareholder returns. There is not much near-term management control over these carrying costs since inventory volumes are constrained by operational requirements and inventory price is determined by the indexed fuel prices embedded in long-term fuel purchase contracts. However, since the absolute amounts of inventory carrying

costs are relatively small, this risk is not viewed as a significant business risk from an investor's perspective.

Q. How are investors currently compensated for the risks that they take relating to fuel?

A. In general, investors are not specifically compensated for the risks they take relating to fuel. Although dependence on imported fuel oil increases business risks, the existing ECAC mechanism significantly mitigates this risk. The risks associated with changes in the fuel inventory carrying costs are generally not significant from an investor's perspective and investors do earn a return on the fuel inventory included in rate base.

Q. What provisions of Act 162 address the ECAC?

A. Act 162 includes the following provisions which were codified in Section 269-16 of the Hawaii Revised Statutes:

> Any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:
> (1) Fairly share the risk of fuel cost changes between the public utility and its customers;
> (2) Provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy;
> (3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
> (4) Preserve, to the extent reasonably possible, the public utility's financial integrity; and
> (5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

Q. Does the design of the current ECAC mechanism meet the requirements of Act 162?

A. Yes. As discussed by Mr. Hee (MECO T-19), MECO's current ECAC mechanism does meet the requirements of Act 162. In the following section, I

will elaborate on certain provisions of Act 162 relating to the impact of ECAC on investors.

Q. Does the design of the current ECAC mechanism "fairly share the risk of fuel cost changes between the public utility and its customers"[14]?

A. Yes. As discussed by Dr. Jeff Makholm in HELCO ST-23, Docket No. 05-0315 (and Mr. Hee in MECO T-19), fuel cost changes include fuel price changes and fuel efficiency changes. Under the existing ECAC, customers generally bear the risk of fuel price changes and shareholders generally bear the risk of fuel efficiency changes. Customers pay less when actual fuel prices decline, and customers pay more when actual fuel prices escalate. In establishing a fair rate of return on equity, the Company's current ECAC is assumed to continue (see Dr. Morin's discussion in MECO T-16). The concept that shareholders do not make any profit from fuel price changes is therefore embedded in the return on equity recommendation. This is "fair" because shareholders do not require compensation for risks that they do not bear.

Q. How is it "fair" that customers bear nearly all the risks and shareholders take minimal risks associated with fuel price changes?

A. It is "fair" because the required rate of return on common equity is relatively lower due to the fact that shareholders take minimal risks associated with fuel price changes. As a result, customers benefit by having lower electric rates that are based on the relatively lower rate of return on common equity.

Q. If customers pay less when actual fuel prices decline, why does the ECAC revenue have a recent history of being positive (i.e., customers pay more than base rates)?

[14] Hawaii Revised Statutes ("HRS") Section 269-16(g)(1).

A. The fuel oil prices used to establish base rates set the "base" in determining whether ECAC is positive or negative. Since under the current ECAC customers will bear nearly all the costs associated with fuel price changes, it does not matter what portion of the fuel cost is reflected in base rates and what portion gets reflected in ECAC. In MECO's 1999 Test Year Rate Case (Docket No. 97-0346), the Company and the Consumer Advocate were able to agree on fuel price estimates, since the ECAC will adjust revenues to reflect the actual cost of fuel.

Also, currently, fuel price is not a driver for determining when a rate case is needed. If base rates are set at a time when fuel prices are relatively low, the ECAC will be positive when fuel prices rise. Conversely, if base rates are set at a time when fuel prices are relatively high, the ECAC will be negative when fuel prices drop.

Q. Does the design of the current ECAC mechanism "preserve, to the extent reasonable possible, the public utility's financial integrity"[15]?

A. Yes. The current ECAC mechanism is a strength in HECO's business risk profile and contributes to MECO and HECO's financial integrity. The monthly adjustment of the existing ECAC also minimizes the recovery time period, further reducing investor uncertainty with respect to recovery of fuel costs.

As I mentioned earlier, S&P has often cited the existing ECAC mechanism as a strength in HECO's credit quality assessment. Conversely, the potential to change the existing ECAC has raised concerns with the rating agencies as noted in S&P's credit assessment of HECO dated November 22, 2006 in Exhibit MECO-1712.

[15] HRS Section 269-16(g)(4).

Q. Does the design of the current ECAC mechanism "minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs"[16]?

A. Yes. The current ECAC design virtually eliminates fuel price changes as a consideration as to when a rate case is necessary.

Q. Are there any alternatives to changing the existing ECAC mechanism if the objective is to "smooth" the impact of fuel price changes on electricity bills?

A. Continuation of the existing ECAC is essential to maintaining the financial integrity of the Company; however, the Company recognizes that volatile fuel prices negatively impact our customers and therefore will consider other means of smoothing the impact of the fuel price changes on customers. Dr. Makholm discusses budget billing and fixed rate billing mechanisms in HELCO ST-23, Docket No. 05-0315.

Q. Has the Company considered implementing a fuel price hedging program?

A. Yes. The Company retained the consulting services of National Economic Research Associates, Inc. ("NERA") to evaluate the issues associated with implementing a fuel price hedging program. NERA's findings relating to hedging options are summarized by Mr. Eugene Meehan in HELCO ST-24, Docket No. 05-0315.

Q. Does the Company propose to implement a fuel price hedging program?

A. No. The Company is not proposing to implement a fuel price hedging program at this time. Mr. Meehan details the numerous considerations that must be addressed before a fuel hedging program can be implemented. As Mr. Hee indicates in MECO T-19, the Company will be exploring budget billing and fixed rate billing options to address rate smoothing.

[16] HRS Section 269-16(g)(5).

Q. What would be necessary if any new or modified fuel cost recovery mechanism is implemented in order to "fairly share the risk of fuel cost changes between the public utility and its customers" and to "preserve, to the extent reasonably possible, the public utility's financial integrity"?

A. Any new or modified fuel cost recovery mechanism that results in increasing investors' risks associated with fuel and/or purchased energy would require an increase in investor compensation through a higher cost of capital for bearing the increased risks. Customers would ultimately bear the higher costs for this increase in cost of capital. See Dr. Morin's discussion in MECO T-16.

Q. What are your conclusions with respect to the ECAC?

A. The existing ECAC is a significant rate adjusting mechanism that helps MECO and HECO maintain their current standing with investors. Fuel and purchased power costs are a significant portion of MECO's expenses and therefore have tremendous potential financial impact. It is essential that the potential creditor and investor implications of any change to the ECAC be carefully and thoroughly considered before implementation.

<u>Utility Industry Restructuring</u>

Q. How has the utility industry changed?

A. Deregulation of the electric utility business was implemented in a substantial number of states in the late 1990's. The impact of deregulation was very different in different states. Perhaps the most obvious failure was that of California with its energy shortfalls and the financial deterioration of its two largest electric utilities: the bankruptcy of Pacific Gas and Electric and near insolvency of Southern California Edison.

Based on S&P data shown below, beginning in 2000 and through 2003, the industry saw widespread financial deterioration and tightening of the capital

markets. In 2004 and 2005, while more balanced than in previous years, there continued to be more downgrades than upgrades. For 2006, there were twenty-one upgrades versus twenty downgrades, in stark contrast to the trend in previous years when rating downgrades outpaced upgrades. Although rating upgrades appear to be rebounding, by looking at the total downgrades vs. upgrades over the period from 2000 to 2006, it appears that Company ratings are still not where they were prior to 2000.

Standard & Poor's Rating Changes[17]

Year	Downgrade	Upgrade	Total	% Downgrade	% Upgrade
2000	65	20	85	76	24
2001	81	29	110	74	26
2002	182	15	197	92	8
2003	139	8	147	95	5
2004	33	18	51	65	35
2005	46	36	82	56	44
2006	20	21	41	49	51

Q. How has the change in the industry impacted MECO?

A. Although MECO did not face the "deregulated" environment that much of the mainland does, the fact that a utility declared bankruptcy changed investors' perception of risk for investor-owned electric utilities and caused much greater and closer scrutiny of the utility regulatory environment. Changes in the regulatory environment, such as those inherent in the RPS law, the increased reliance on DSM (but with changes in DSM market structure, cost recovery, and incentive mechanisms), and the competitive bidding requirement for new generation, could significantly impact MECO's financial performance.

Throughout the industry, there is increased awareness that historical regulatory stability does not assure current and future regulatory stability.

[17] See S&P articles "U.S. Utility Downside Rating Actions Moderated Significantly in 2004" and "Pace of U.S. Utility Rating Actions Picked Up in 2005; Downgrades Dominate" filed on May 5, 2006 in Docket No. 05-0315 (HELCO 2006 TY Rate Case), Exhibit HELCO-1811 and HELCO-1812; and "Industry Report Card: Despite Demands for Increased Capital Spending, U.S. Utility Ratings Should Remain Stable" in MECO-1713.

Investors are increasingly sensitive to the risk associated with changes in the way utilities are regulated. Investors want confidence that the regulators' decisions will be consistent and fair.

Scrutiny of and by Credit Rating Agencies

Q. How did the increased scrutiny of credit rating agencies impact MECO?

A. Increased scrutiny of credit rating agencies prompted the credit rating agencies to reassess how they determine credit ratings. Some examples of what MECO saw as changes at the credit rating agencies included: additional assessments of financial arrangements, renewed focus on established criteria for qualitative and quantitative measures used to establish credit ratings, and more stringent adherence to the range of values used in quantified measures.

Q. What was involved in the assessment of financial arrangements?

A. Moody's asked the Company to provide a listing of any "rating triggers"[18] contained in any contract or arrangement and copies of HECO's line of credit agreements. S&P requested liquidity information and requested responses to another survey regarding rating triggers, which need to be updated annually.

Q. What are some examples of renewed focus on established criteria?

A. As cited in HECO's 2005 Test Year Rate Case (Docket No. 04-0113, T-21 filed on November 12, 2004), in May 2003, S&P published an update of its methodology for evaluating PPAs entitled "'Buy Versus Build': Debt Aspects of Purchased-Power Agreements" (see Docket No. 04-0113, Exhibit HECO-2111, pages 1 to 5), and in 2004, S&P published new guidelines for business risk assessments entitled "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised" (see Docket No. 04-0113,

[18] A "rating trigger" is when a contract or arrangement includes a provision that is triggered by a certain type of credit rating change.

Exhibit HECO-2112, pages 1 to 19). In addition, in 2006, S&P reemphasized their key credit factors in the publication entitled "Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers" (see Exhibit MECO-1708) and requested comments regarding its methodology for imputing debt to purchased power obligations involving utility companies (see Exhibit MECO-1714).

Q. Please provide an example of more stringent adherence to guidelines.

A. S&P required companies to maintain financial ratios within stated criteria.

<u>SFAS 158 – Pensions and Other Postretirement Benefits</u>

Q. What is SFAS 158?

A. Statement of Financial Accounting Standards No. 158 ("SFAS 158"), "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)", is a recently-issued accounting guidance. SFAS 158 changes the financial statement reporting requirements for defined benefit pension plans and postretirement benefits other than pensions ("OPEB"). As discussed by Mr. Matsunaga in MECO T-9, SFAS 158 requires the Company to (1) recognize on its balance sheet, the overfunded or underfunded status of its defined benefit pension plan (based on the difference between the fair value of the plan assets and the projected benefit obligation ("PBO")) and OPEB plan (based on the difference between the fair value of the plan assets and the accumulated postretirement benefit obligation("APBO")), (2) recognize as a component of accumulated other comprehensive income ("AOCI"), net of tax, the actuarial gains and losses and the prior service costs and credits that arise during the period but are not recognized as components of net periodic pension costs and net periodic benefit costs, and (3) other provisions.

Q. How has SFAS 158 impacted MECO?

A. As explained by Mr. Lyle Matsunaga in MECO T-9, the Company's pension and OPEB plans were underfunded as of December 31, 2006 due to the fair value of these plans being less than the PBO and APBO at that time. For financial statement purposes, as of December 31, 2006, MECO: (1) recognized a pension liability and OPEB liability; (2) reversed the existing prepaid pension asset on the balance sheet and, (3) reflected charges to AOCI for pension and OPEB as an offset to equity. Mr. Matsunaga describes the impact of SFAS 158 in MECO T-9.

Q. How was the funded status of the Company's benefit plans viewed by investors prior to the issuance of SFAS 158?

A. Information regarding the funding status of the pension and OPEB plans has been disclosed to investors since the implementation of SFAS 87, "Employers' Accounting for Pensions" (issued in December 1985) and SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pensions" (issued in December 1990). Prior to the issuance of SFAS 158, S&P indicated in published industry guidance that it made the adjustments to amounts reported in financial reports to reflect the funded status of pension plans.[19] However, in the past, the Companies did not see any documentation that S&P applied these adjustments to the balances reported in HECO's consolidated financial statements in its analysis of HECO's financial ratios. Although the Companies did not specifically address this issue with S&P, it appeared that past regulatory orders supporting the recoverability of pension costs gave S&P sufficient comfort that pension costs are ultimately recoverable in the Companies' respective rates and therefore S&P did

[19] S&P article, "No Major Shifts in U.S. Utilities' Pension Funding Status", dated June 12, 2006 (see exhibit MECO-1715)

not feel that it was necessary to adjust amounts reported on the balance sheet to reflect the underfunded status of the Companies' pension plan.

Q. How have other utilities treated pension and/or OPEB underfunding for financial statement purposes?

A. Many utilities have recorded regulatory assets for pension amounts that would have been charged to AOCI under SFAS 87[20]. I expect that many more utilities face potential AOCI charges for pension and OPEB under the changes in accounting resulting from the issuance of SFAS 158. This is because SFAS 158 uses a higher measure of pension liability and added the requirement to record AOCI charges for OPEB funding shortfalls. Because SFAS 158 applies to financial statements as of December 31, 2006 (at the earliest), financial statements which adopt SFAS 158 are not yet available. The recordation of a regulatory asset can be based on a specific order by a regulatory commission or can be based on management's assessment of the probability of future cost recovery of that asset. Further, I am aware that one of the large audit firms (that audits many electric utilities) has advised its clients that if they have in the past gotten recovery in rates of pension costs in accordance with SFAS 87 and OPEB cost in accordance with SFAS 106, the history of regulatory support is sufficient basis to establish a regulatory asset and reverse the AOCI charge[21]. Since many electric utilities have gotten recovery of pension cost in accordance with SFAS 87 and OPEB costs in accordance with SFAS 106, I expect many utilities will record regulatory assets for the amounts which would otherwise be charged to AOCI.

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[20] See listing of utilities that received Commission approval of regulatory asset treatment for the portion of the minimum pension liability charged to AOCI in Docket No. 05-0310, Application filed December 8, 2005, footnote 11 on page 14 and the Companies' response to CA-IR-4. There were no charges to AOCI for OPEB under SFAS 106.

[21] See exhibit MECO-1716.

Q. What would constitute "recovery in rates of pension costs in accordance with SFAS 87 and OPEB costs in accordance with SFAS 106"?

A. This would mean recovery through rates of the Company's pension expense (i.e., net periodic pension costs or "NPPC") and OPEB expense (i.e., net periodic benefits costs or "NPBC").

Q. Has the Commission approved the recovery of the NPPC and the NPBC by MECO and its affiliates.

A. Yes. As discussed by Ms. Julie Price in MECO T-10, the Commission has approved the recovery of the NPPC and NPBC in numerous prior proceedings.

Q. Please discuss the impact of the charge to AOCI on the Company's financial ratios and the credit rating agencies' evaluation of the Company.

A. The recognition of a pension liability and charge to AOCI, results in an increase in liabilities and decrease in equity. We are uncertain as to how the credit rating agencies will view these changes. Based on my discussions with one of the rating agencies, my expectation is that if the Company is allowed a return on the pension asset in rate base and is allowed to restore equity for the AOCI for ratemaking purposes, there may be no impact on the way we are viewed by the credit rating agencies.

If, however, the Company is not allowed a return on the pension asset in rate base or is not allowed to restore equity for the AOCI for ratemaking purposes, these changes would likely negatively impact the total debt/total capital and funds from operations interest coverage ratios. If the Company is denied its proposed ratemaking treatment, it is likely that the credit rating agencies would include the minimum liability in the debt component in their calculation of total debt/total capital. Such treatment would be consistent with their published methodology based on pre-SFAS 158 financial statements. An increase in debt will increase the

total debt/total capital ratio. Additionally, if the Company is denied either aspect of regulatory support, it would result in lower operating income. Further, this regulatory treatment would presumably be applied to HECO and HELCO, which would also result in lower operating income at HECO and HELCO. The consolidated impact of this lack of regulatory support would result in credit quality degradation. Credit quality degradation would result in a relatively higher cost of debt. Lower operating income and higher interest costs would lower the funds from operations interest coverage ratio.

Q. How have the credit rating agencies reacted to the financial statement recognition of AOCI charges for the financial statements as of December 31, 2006?

A. Upon the Commission's decision in the AOCI docket, HECO filed a Form 8K with the Securities and Exchange Commission explaining the decision[22]. I received a call from one of the rating agencies. I explained that the decision in the AOCI docket did not address the ratemaking treatment of the benefit plans. The primary concern of the credit rating agency is clearly the ratemaking treatment of the pension or OPEB underfunding. If the Company has regulatory decisions that support a return on the pension asset and recovery of pension and OPEB costs based on SFAS 87 and 106, respectively, I expect that this credit rating agency would not make any risk adjustment for this issue.

Q. How does MECO propose to treat the AOCI charges for ratemaking purposes?

A. For ratemaking purposes, MECO proposes to restore book equity for the AOCI charges in determining the equity balance for ratemaking purposes. I discuss this further later in my testimony. The AOCI charges relating to the qualified pension plan and the OPEB plans (excluding the executive life portion) are included in the reconciliation of pension and OPEB balances in determining rate base. The

[22] Form 8-K dated January 26,2007 (see exhibit MECO-1717).

pension asset, which is comprised of the cumulative pension contributions net of the cumulative pension cost recognized, is equal to the pension AOCI charge net of the pension liability. The OPEB amount of zero in rate base is comprised of the cumulative OPEB contributions net of the cumulative OPEB costs recognized, which is equal to the OPEB AOCI charge and regulatory asset net of the OPEB liabilities. Mr. Matsunaga provides the details of the pension and OPEB rate base amounts in MECO T-9. The AOCI charges relating to the non-qualified pension plan and the executive life portion of OPEB are not included in rate base because the costs associated with these plans have been disallowed for ratemaking purposes in previous rate cases and are not included for ratemaking purposes in this case, although the Company continues to reserve the right to raise the issue of cost recovery for these items in future rate cases.

Q. How important is the rate base treatment of the pension asset to investors?

A. Rate base treatment of the pension asset is extremely important to investors as it allows investors the opportunity to earn on invested funds. Note that the net of the pension liability and the pension AOCI charge is exactly the same as the prepaid pension asset that would exist if the recognition of a pension liability was not required. The key point is that cumulative pension fund contributions have exceeded cumulative pension cost recognized and the net cumulative difference between the contributions and costs must be recognized in rate base for investors and ratepayers to be treated equitably.

Q. Are you aware of any recent ratemaking actions directly relating to treatment of pensions?

A. Yes. In July 2006, the Illinois Commerce Commission issued an order in Commonwealth Edison Company's ("ComEd") electric delivery rate increase

1 request.[23] A disallowance of an $854 million pension asset from rate base, which
2 was an infusion from ComEd's parent, Exelon Corporation, was a significant
3 ruling in that order.
4 Q. How did the investment community react to this ratemaking action?
5 A. The day following the order, Moody's downgraded ComEd's unsecured debt.
6 S&P also subsequently downgraded ComEd. Although I cannot speak
7 definitively to the connection between the pension ratemaking actions and the
8 credit rating actions, it appears that the pension asset disallowance contributed
9 negatively to the credit assessment of ComEd.
10 Q. Please summarize the investor concerns relating to pensions.
11 A. The key investor concerns in MECO's case are: recovery of current benefit costs;
12 mechanism for recovery of future benefit costs; return on any net investor-
13 provided funds (or reduction in rate base for any non-investor provided funds);
14 rate of return on equity which takes into consideration the business risk of benefit
15 cost recovery; and restored equity balances to reverse the AOCI charge. To the
16 extent that regulatory treatment of benefit costs changes the business risk profile
17 of the Company, it may impact the equity return expectations of the investor.
18 Summary of Business Risks
19 Q. How do MECO's business risks impact its capital structure?
20 A. Increased business risks have increased the pressure to reduce financial risk in
21 order to maintain the Company's credit rating. Since MECO cannot control much
22 of the business risk it faces, MECO must be resolute in controlling its financial
23 risk. The primary means of reducing its financial risk is by increasing or, at
24 minimum, maintaining the proportion of equity in its capital structure.

[23] Illinois Commerce Commission Order dated July 26, 2006 in Docket No. 05-0597.

Financial Risk

Q. What do rating agencies consider in evaluating financial risk?

A. Financial risk considerations include financial characteristics, financial policy, profitability, capital structure, cash flow protection and financial flexibility.

Q. How do rating agencies measure financial risk?

A. To assess the financial risk of a company, the rating agencies examine a number of measures, including the following[24]:

1) Funds from operations/interest coverage – measure of ability to pay interest from operations.

2) Funds from operations/total debt – measure of ability to pay total debt from operations.

3) Total debt to total capital – measure of the financial leverage used by the company.

Q. What are MECO's projected ratios for the test year?

A. MECO's projected ratios are provided on MECO-1718.

Q. What are the implications of the projected ratios?

A. A comparison of MECO's projected ratios to the financial guidelines applicable to MECO is shown on MECO-1718. Based on a current business profile assignment of "5", without rate relief:

- the funds from operations/interest coverage ratio is indicative of an AA rating (5.0 in AA range of 4.5-5.5),
- the funds from operations/total debt ratio is indicative of an A rating (24 in A range of 22-30) and

[24] See Standard & Poors "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised" dated June 2, 2004 in Docket No. 04-0113 (HECO 2005 TY Rate Case), Exhibit 2112, pages 1 to 19 filed on November 12, 2004.

- the total debt/total capital ratio is indicative of an A rating (47 in A range of 50-42).

With rate relief:

- the funds from operations/interest coverage ratio is indicative of an AA rating (6.0 in AA range of 4.5-5.5),
- the funds from operations/total debt ratio is indicative of an A rating (30 in A range of 22-30) and
- no change to the total debt/total capital ratio which is indicative of an A rating (47 in A range of 50-42).

Q. How does the Company's capital structure affect its financial risk?

A. Companies that have more debt (less equity) are deemed to have higher financial risk than companies that have less debt (more equity).

Q. What adjustments to debt amounts reported on the Company's financial statements do credit rating agencies make?

A. S&P has indicated that they make adjustments in two areas:

1) <u>Imputed debt for PPAs and operating leases</u>

The credit rating agencies have determined that certain obligations of the Company that are not reported as liabilities on the Company's balance sheet should be reflected as debt in the ratios used to evaluate the Company's risk profile. In order to capture the risks associated with these obligations, the credit rating agencies calculate "imputed debt." In MECO's case, the credit rating agencies impute debt for the HC&S firm capacity PPA and long-term operating lease obligations.

2) <u>Equity credit for hybrid securities</u>

Hybrid securities have certain features that are equity-like. In calculating ratios, S&P treats hybrids as debt, but gives some equity credit for the hybrids. The equity aspects of the hybrids decline over time.

Q. Why is it important for the Company to establish and maintain a sound capital structure?

A. Whereas the Company has little control over many of the business risks it faces, the capital structure impact on financial risk is a risk that the Company can largely control.

Q. What is the Company's target capital structure ratio?

A. The Company hopes to manage its capital structure to maintain a ratio of common equity (excluding the AOCI charge) to total capitalization of about 54% for book purposes.

Q. How did the Company establish its capital structure target?

A. The capital structure target was established to at least maintain MECO's existing credit ratings. MECO has ongoing discussions and periodic meetings with the credit rating agencies in order to stay informed of investor perceptions of the Company. Feedback from the rating agencies was key in establishing these ratios.

Q. How do these ratios compare to what was allowed by the Commission in MECO's 1999 test year rate case, Docket No. 97-0346?

A. In D&O 16922, Docket No. 97-0346, the Commission established rates based on a capital structure of: 0% short-term debt, 44.03% long-term debt, 5.75% hybrid securities, 1.38% preferred stock, and 48.84% common equity. The proportion of common equity increased as MECO's business risk has increased. In response to the increase in business risk, MECO has found it necessary for the proportion of equity to increase. On several occasions over the past several years, we have received indications from the rating agencies that lower credit ratings were being

considered unless HECO was able to increase its equity in the capital structure. As a wholly-owned subsidiary of HECO, any increases in MECO's common equity results in increases to HECO's equity in the capital structure.

Q. How will customers benefit from the increase in equity in MECO's capital structure?

A. Maintaining credit quality will provide continued access to the capital markets to fund capital projects in order to fulfill MECO's obligation to provide electric service. It provides continued assurance of reasonable financing rates, terms and conditions.

SOURCES OF INVESTOR FUNDS

Q. What are the Company's sources of capital funds?

A. The Company has the following sources of capital funds:

1) Short-Term Borrowings,
2) Long-Term Borrowings,
3) Hybrid Securities,
4) Cumulative Preferred Stock, and
5) Common Stock.

Q. Please describe the Company's short-term borrowings.

A. MECO borrows short-term from HECO, when MECO has cash needs.

Q. Please describe the Company's long-term borrowings.

A. The Company's long-term borrowings consist of revenue bonds issued by the State of Hawaii. The proceeds of the revenue bond issuances are loaned to MECO by the State. MECO is obligated to repay the interest and principal of the bonds. Interest income to revenue bondholders is generally not taxable for Federal and State of Hawaii income tax purposes, therefore investors are willing to accept lower interest rates than taxable investments. Ratepayers benefit

through the lower cost source of funds, as will be more fully described later in my testimony when I discuss the revenue bond savings calculations.

Q. Please describe the revenue bond issuance that is reflected in the Company's long-term borrowings for the 2007 Test Year.

A. At the time the estimates were prepared, the Company assumed it would issue $20 million of revenue bonds, at a 5.50% interest rate. An amended application for the approval of the revenue bond financing was filed with the Commission on October 27, 2006, Docket No. 05-0330, and is pending approval. The long-term borrowings for 2007 may be updated later, depending on the status of the proposed financing.

Q. Please describe the Company's hybrid securities.

A. Hybrid securities have some debt-like features and some equity-like features, hence the name "hybrid". MECO's hybrid securities consist of junior subordinated deferrable interest debentures ("QUIDS"). The QUIDS are sold to trusts which exist for the purpose of issuing cumulative quarterly income preferred securities ("QUIPS"). The QUIPS have features similar to the QUIDS and are sold to third parties. An illustration of the transaction is shown in exhibit HECO-2117 of Docket No. 04-0113 (HECO 2005 TY Rate Case) filed on November 12, 2004. QUIDS have a lower after-tax cost than preferred stock because the periodic interest payments are deductible from taxable income, as are interest payments on traditional long-term debt. The equity-like features of the QUIDS are that they are deeply subordinated, have long maturity, and have a feature that permits the deferral of payments for a period of time.

Q. Please describe the Company's cumulative preferred stock.

A. Preferred stock issuances have stated dividend rates and may have sinking fund redemption provisions. Preferred dividends must be paid before dividends to the common shareholder can be paid.

Q. Please describe the Company's common equity.

A. As a wholly-owned subsidiary of HECO, the Company's common equity balance consists of the funds invested by its shareholder as well as income earned by the shareholder, but not distributed to it (retained earnings).

CAPITAL STRUCTURE

Q. How did you estimate the balances of each of the sources of investor funds?

A. We started with the recorded balances as of December 31, 2005, then we estimated changes in 2006 and 2007.

Q. How were the changes estimated?

A. The estimate of changes was derived from the sources and uses of investor funds (e.g., earnings and capital expenditures) and redemptions or new issuances of external financing.

Q. How is MECO's external financing plan determined?

A. The Company's external financing plan is structured to achieve the sound capital structure discussed earlier in my testimony.

Short-Term Borrowing Balance

Q. What is the average short-term borrowing balance for test year 2007?

A. The Company estimates average short-term borrowings of $5 million. The calculation of the average balance is shown on MECO-1702.

Q. How was the average annual short-term debt amount for test year 2007 computed?

A. The average short-term debt amount was computed by averaging the estimated short-term debt balances at the end of 2006 and 2007.

Q. How was the year-end 2006 and 2007 short-term debt balance estimated?

A. We started with the recorded short-term debt balance as of December 31, 2005. An adjustment was made for the estimated change in 2006 to come to an estimated year-end 2006 balance. The estimated year-end 2006 balance was then adjusted for estimated changes in 2007 to come to an estimated year-end 2007 balance.

Q. What does the negative estimated balance at year-end 2007 represent?

A. The estimated negative balance at year-end 2007 represents a short-term investment of funds.

Q. Why is the investment included in the calculation of average borrowings for the test year?

A. The estimated balance as of December 31, 2007 is for MECO to be in a short-term investment position. Including the short-term investment balance (as a negative short-term borrowing) in calculating the average cost of capital structure balance results in a reduction to interest expense. In effect, rather than including interest income in the revenue requirement calculation, MECO has reduced interest expense.

Long-Term Borrowing Balance

Q. What is the average long-term borrowing balance for test year 2007?

A. The Company estimates average long-term borrowings of $151 million in the 2007 test year. The detailed list of revenue bond issuances, and other adjustments that constitute the average balance, are shown on MECO-1703.

Q. How was the average annual long-term debt amount for test year 2007 computed?

A. The average long-term debt amount was computed by averaging the net proceeds of long-term debt at the end of 2006 and 2007.

Q. How were the year-end 2006 and 2007 net proceeds of long-term debt balances estimated?

A. We began with the long term debt balance as of December 31, 2005. Based on the expected financing needs of the Company, the terms of the debt currently outstanding and the prevailing interest rates, we anticipate that MECO would have one revenue bond issuance in 2007. An amended application for the approval to issue special purpose revenue bonds was filed with the Commission on October 27, 2006 in Docket No. 05-0330.

We then calculated the net proceeds as of year-end 2006 and 2007. The net proceeds are equal to the face amount, or par value, of the securities, less any unamortized balances of:

1) issuance costs,
2) issuance discounts,
3) revenue bond investment differentials, and
4) redemption costs.

Only "drawndown amounts" are included in the calculation of net proceeds.

Q. What are issuance costs?

A. Issuance costs are costs incurred as a result of selling securities. They include legal costs, insurance costs, printing costs, underwriters' fees, and other miscellaneous costs of issuing the securities, including MECO's share of the issuance cost related to HECO's syndicated credit facility.

Q. What is the syndicated credit facility ("SCF")?

A. The SCF is a single credit agreement with a group of eight lenders that collectively aggregate $175 million in revolving commitments to lend to HECO under the single credit agreement. On August 30, 2006, HECO filed an application with the Commission for approval of the SCF for a five-year term ending March 31, 2011. Commission approval of the five-year SCF will automatically extend HECO's current 364-day SCF ending on March 29, 2007

(see Docket No. 2006-0360). As such, MECO proposes to amortize the SCF issuance costs over a 5-year period (equivalent to the 5-year term of the SCF agreement, subject to Commission approval).

Q. Why is the SCF issuance cost included in determining the net proceeds for long-term debt in the cost of capital calculation?

A. The SCF issuance cost relates to the cost of establishing financing for the Company. Although the SCF is maintained by HECO, it principally supports the issuance of commercial paper, which HECO may issue on behalf of MECO when MECO has cash needs. Thus, if the Commission approves the multi-year SCF for HECO, the credit facility will be available for HECO to back-up its commercial paper program and borrow on behalf of MECO over the 5-year period.

Q. What are issuance discounts?

A. Issuing a security at a discount means that it was sold for less than its face value. At maturity, the full face value will be paid to the bondholder. This approach is attractive to certain buyers who are willing to take the security at a lower effective interest rate in order to get the capital appreciation from the discounted price to the par value at maturity.

Q. Why are bonds sometimes sold at a discount?

A. Selling at a discount can sometimes reduce the effective cost of the bonds, including the amortization of the issuance discount.

Q. What are revenue bond investment differentials?

A. The proceeds from revenue bond sales are put in a construction fund administered by a Trustee. "Drawdowns" from the fund are made for qualified projects. The undrawn proceeds left in the construction fund are invested and earn interest income until they are needed to fund projects. At the same time, interest payments must be made to the revenue bond holders for all of the revenue bonds,

including those bonds that provided money still in the construction fund. The investment differential is effectively the difference between the earnings and the interest costs of the undrawn proceeds in the construction fund.

Q. What are the possible types of revenue bond investment differentials?

A. Revenue bond investment differentials can result in any of these situations:

1) "net expense", or negative investment differential -- interest income is less than the interest expense associated with the undrawn proceeds;

2) "net income", or positive investment differential -- interest income is more than the interest expense associated with the undrawn proceeds; or

3) No investment differential -- net expense equals net income.

MECO-WP-1703 p. 5 shows details of the revenue bond investment differentials.

Q. What are redemption costs?

A. Redemption costs are incurred as a result of redeeming securities early (before their maturity dates) in order to achieve cost savings by replacing existing securities with less expensive securities. When the Company redeems a security before its maturity date, it is usually required to pay to the holder of the security its par value plus an additional amount called a redemption premium. Redemption costs include redemption premiums and other miscellaneous costs such as legal and trustee fees.

Q. What are "drawndown amounts"?

A. The proceeds from revenue bond sales are put in a construction fund administered by a Trustee. "Drawdowns" from the fund are made for qualified expenditures. "Drawndown amounts" refer to the disbursements from the fund to the Company.

Q. Why are some funds left undrawn?

A. Funds are left in the construction fund when there are no qualified expenditures to support the disbursement from the fund or it is not economic to support the disbursement from the fund with a specific project due to tax consequences.

Q. Why does MECO sometimes sell bonds before it needs the money?

A. MECO sometimes sells the bonds before it needs the money for several reasons:

1) to obtain as much low cost tax-exempt financing as it can before possible changes in legislation curtail the availability of this form of financing;

2) to secure an allocation of revenue bonds from the limited amount of revenue bond "cap" that the State of Hawaii Department of Budget and Finance receives each year; and

3) to save costs; it generally costs less to do less frequent, larger sales, instead of several smaller sales.

However, MECO would sell bonds only if it is projecting an eventual need for the funds.

Q. Why are the net proceeds used to determine the average balance?

A. We use the net proceeds because the net amount is all the funds from those security sales that provide cash available to be invested in assets.

<u>Hybrid Securities Balance</u>

Q. What is the average hybrid security balance for test year 2007?

A. The Company estimates average hybrid securities of $9 million. The hybrid security issuance that constitutes the average balance is shown on MECO-1704.

Q. How was the average annual hybrid security amount for test year 2007 computed?

A. The average hybrid security amount was computed by averaging the net proceeds of hybrid securities at the end of 2006 and 2007.

Q. How were the year-end 2006 and 2007 net proceeds of hybrid security balances estimated?

A. We began with the balance as of December 31, 2005. MECO does not anticipate any redemptions or new issuances to impact the hybrid securities balance in the remainder of 2006 or in 2007.

We then calculated the net proceeds as of year-end 2006 and 2007. The net proceeds for hybrid securities are equal to the face amount of the QUIDS less any unamortized balances of issuance costs and redemption costs.

Preferred Stock Balance

Q. What is the average preferred stock balance for test year 2007?

A. The Company estimates average preferred stock of $5 million. The detailed list of preferred stock issuances and adjustments which constitute the average balance is shown on MECO-1705.

Q. How was the average annual preferred stock amount for test year 2007 computed?

A. The average preferred stock amount was computed by averaging the net proceeds of preferred stock at the end of 2006 and 2007.

Q. How were the year-end 2006 and 2007 net proceeds of preferred stock balances estimated?

A. We began with the December 31, 2005 balances. The Company does not anticipate any new issuances or redemptions of preferred stock between the recorded year-end 2005 through 2006 and 2007. The net proceeds are equal to the face amount, or par value, of the preferred stock, less any unamortized balances of issuance costs. The only change to the balance during that period is the amortization of unamortized costs.

Common Equity Balance

Q. What is the average common equity balance for test year 2007?

A. The Company estimates average common equity of $206 million. The calculation of the average balance is shown on MECO-1706.

Q. How was the average common equity amount for test year 2007 computed?

A. The average common equity amount was computed by averaging the net proceeds of common equity for ratemaking at the end of 2006 and 2007.

Q. How were the year-end 2006 and 2007 net proceeds of common equity balance estimated?

A. We began with the recorded December 31, 2005 common equity balance. The unamortized issuance cost of preferred stock was restored (added back) to the recorded common equity balance. The result is the common equity balance for ratemaking purposes as of December 31, 2005.

We then reflected the activity for 2006 and 2007 for the estimated net changes in accumulated retained earnings and estimated net AOCI adjustments. This calculation is shown in MECO-1706.

Restoration of Unamortized Preferred Stock Issuance Costs

Q. Why is an amount of common equity equal to the unamortized preferred stock issuance costs restored to the book common equity balance (included in "Restoration" on MECO-1706)?

A. For financial statement purposes, the unamortized issuance costs of preferred stock are shown as a reduction to common equity. For ratemaking purposes, however, they are shown as a deduction to preferred stock rather than common equity since these costs relate to preferred stock.

Q. Has the Commission used this adjustment in the past in calculating the Company's common equity balance?

A. Yes. In all final Decision and Orders for the Companies' recent rate cases, the Commission used this adjustment to restore common equity.

Charges to Accumulated Other Comprehensive Income

Q. What is AOCI?

A. Generally accepted accounting standards prescribe that certain situations result in charges to common equity, net of income taxes, which are not reflected on the Company's income statement. These charges are made to an equity account entitled "accumulated other comprehensive income." As I discussed earlier, SFAS 158 changed the criteria which trigger AOCI charges for defined-benefit pension and OPEB plans.

Q. Has the Company incurred any AOCI charges to equity?

A. Yes. For financial statement reporting purposes, the Company has incurred AOCI charges related to pension and OPEB plans as of December 31, 2006.

Q. How does the Company propose to treat the AOCI charges in the cost of capital for ratemaking purposes?

A. For ratemaking purposes, the Company has restored common equity for the AOCI charges.

Q. Why is it proper to restore common equity for the AOCI charges for ratemaking purposes?

A. Shareholders have invested funds that exclude the deduction from (or addition to) equity for financial statement purposes for AOCI and should be allowed a return on invested funds. Therefore, the ratemaking cost of capital should be based on the equity balance excluding the deduction (or addition) for AOCI. The AOCI charge is a non-cash item. Therefore, including it in the equity for ratemaking purposes will misstate equity funds invested. If the AOCI adjustment is included in ratemaking equity, the equity ratemaking balance will fluctuate (higher or lower) depending primarily on the market value of the pension and OPEB funds. On Exhibit MECO-1719, I provide an illustration of what the AOCI charge or addition to equity would have been in the period 1995 to 2006 if SFAS 158 had

been in effect. As you can see, AOCI would have increased equity in 1996 through 2001. In some of those years, the increase would have been significant.

Q. Does the Commission's ruling in Docket No. 05-0310 impact the ratemaking treatment of the AOCI charge?

A. No. In Docket No. 05-0310, the Commission ruled that the Company could not record a regulatory asset. The Commission did not address the ratemaking treatment of the AOCI charge.

Capital Structure Summary

Q. Ms. Sekimura, please summarize your testimony of capital structure.

A. A capital structure comprised of 1.27% short-term debt, 40.15% long-term debt, 2.45% hybrid securities, 1.25% cumulative preferred stock, and 54.89% common equity is appropriate.

CAPITAL COSTS

Short-Term Borrowings

Q. What is the estimated cost of short-term borrowings for the test year 2007?

A. The cost of short-term borrowings for the test year 2007 is estimated to be 5.0%.

Q. How was the cost of short-term borrowings determined?

A. We began with the most recent Blue Chip Financial Forecast[25] for federal funds which showed quarterly rates for 2007 of: 5.2%, 5.1%, 5.0%, and 4.9%. We calculated an average for 2007 of 5.05%. We increased this federal funds rate by 10 basis points to reflect the typical spread between federal funds rates and HECO's short-term borrowing rate, and thus rounded our estimate to 5.0%.

Long-Term Borrowings

Q. What is the estimated effective cost of long-term borrowings for the test year 2007?

[25] Forecast dated December 1, 2006.

A. The estimated effective cost of long-term borrowings for the test year 2007 is 6.11%.

Q. How was the effective cost of long-term borrowings determined?

A. The effective cost of long-term borrowings was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on MECO-1703.

Q. What makes up the annual requirements?

A. The annual requirements consist of the annual interest expense, the annual amortization of various costs of issuing and carrying the security, and the annual insurance premiums. The average annual requirements for the test year are shown in column (F) of MECO-1703.

Q. What types of amortized costs are included in calculating the annual requirement?

A. Costs associated with financings that are incurred in only specific periods, but result in a benefit during the entire life of the security, are amortized. Amortized costs include:

1) issuance costs and issuance discounts,
2) revenue bond investment differentials, and
3) redemption costs, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds.

<u>Issuance Costs and Issuance Discounts</u>

Q. Why should ratepayers pay the costs of issuing bonds or issuing them at a discount?

A. It is appropriate for ratepayers to pay for the issuance costs and issuance discounts because the ratepayers get the benefits from these actions.

1 Revenue Bond Investment Differentials

2 Q. How is the revenue bond investment differential treated for ratemaking purposes?

3 A. The treatment of the revenue bond investment differential depends on whether
4 there is net income or net expense.

5 Q. When there is net income in the revenue bond investment differential, how is it
6 accounted for in the effective cost of long-term debt?

7 A. When there is net income, there are two possible situations:

8 1) When net income does not have to be rebated to the IRS, the positive
9 investment differential is amortized, effectively reducing the annual
10 requirements of the bonds.

11 2) When net income must be rebated to the IRS, the Company's net proceeds
12 available for use would be increased by any net income until it is rebated to
13 the IRS in five years.[26] This was done for the Series 1988 revenue bonds.
14 Since increased net proceeds, for the same annual requirement, means a
15 lower effective cost of the bonds, customers would receive the benefit for
16 the five years that any net income is held by the Company.

17 Q. When there is net expense in the revenue bond investment differential, how does
18 the revenue bond investment differential affect the annual requirements of the
19 revenue bonds?

20 A. When there is net expense, investment differentials are generally amortized (in
21 proportion to the drawn funds) over the life of the revenue bonds. This effectively
22 increases the annual requirements of the bonds.

[26] Generally, for revenue bonds issued after 1986, the net income must be rebated to the IRS (with some exceptions), with the first rebate payment due five years after the issue.

Redemption Costs and Unamortized Costs for Redeemed Bonds

Q. Why should ratepayers pay the costs of redeeming bonds at a premium, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds?

A. It is appropriate for ratepayers to pay for redemption premiums, unamortized issuance costs for redeemed bonds, and unamortized investment income differential balances for redeemed bonds because ratepayers get the benefits from the bond redemption. When MECO pays a premium to refund a high interest rate bond early, the customers benefit from the lower rates of the new issuance.

Q. Has the Commission included these types of costs in determining the effective costs of the Company's securities in prior rate cases?

A. Yes. In all final Decision and Orders for the Companies' recent rate cases, the Commission has included these types of costs in the effective cost calculation.

Hybrid Securities

Q. What is the estimated cost of hybrid securities for the test year 2007?

A. The estimated effective cost of hybrid securities for the test year 2007 is 7.47%.

Q. How was the cost of hybrid securities determined?

A. The effective cost of hybrid securities was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on MECO-1704.

Preferred Stock

Q. What is the estimated cost of preferred stock for the test year 2007?

A. The estimated effective cost of preferred stock for the test year 2007 is 8.34%.

Q. How was the cost of preferred stock determined?

A. The effective cost of preferred stock was calculated by dividing (a) the total annual requirement for interest and the amortization of unamortized items by (b) the net proceeds received from the sale of the securities. This calculation is shown on MECO-1705.

Common Equity

Q. What would be a fair and reasonable rate of return on common stock equity to be used by the Commission in determining the revenue requirements in this docket?

A. In MECO T-16, Dr. Roger Morin, a Professor of Finance and an expert in this area, has determined that a fair and reasonable return on common equity for MECO for test year 2007 would be 11.25%. Dr. Morin did a comprehensive analysis before arriving at his judgment on a fair and reasonable return on common equity for MECO.

Q. Do you accept Dr. Morin's conclusion that a fair return on common equity for MECO in this docket is 11.25%?

A. Yes. An allowed rate of return on common equity of 11.25% should give the Company an opportunity to earn a fair and reasonable rate of return in the test year, assuming that the Company obtains adequate rate relief by the beginning of the test year.

Q. When was Dr. Morin's appraisal of the fair return on equity ("ROE") for MECO conducted?

A. It was completed in October 2006.

Capital Costs Summary

Q. Ms. Sekimura, please summarize your testimony on costs of capital.

A. The test year estimates of capital costs for the test year of: short-term debt 5.00%, long-term debt 6.11%, hybrid securities 7.47%, cumulative preferred stock 8.34%, and common equity 11.25% are appropriate.

DETAILED ANALYSIS OF HEI IMPACT NOT NEEDED

Q. Has a comprehensive analysis of HEI's impact on the Companies' cost of capital been done before?

A. Yes. Dennis Thomas and Associates, an independent consultant, was hired to assist the Public Utilities Commission in its investigation of the effects of the relationship between HEI and HECO on the operations of HECO and its electric subsidiaries, HELCO and MECO, and their respective ratepayers. In January 1995, Dennis Thomas and Associates issued a report entitled, "Review of the Relationship between Hawaiian Electric Industries and Hawaiian Electric Company" (the "Thomas Report").

Q. What did the Thomas Report conclude regarding the impact of HEI on the Companies' cost of capital?

A. The Thomas Report concluded the following:

1) "Any impacts of diversification on the yield of HECO's debt obligations have likely been transitory and small. Hence, there is no reason to believe that the debt costs reflected in HECO's rates have been changed as a result of HEI's past diversification activities." (Thomas Report, page 132)

2) "Cost of equity witnesses in HECO rate cases have consistently based their estimates on HECO's financial parameters and estimates for the cost of equity to comparable electric utilities . . . the policy of looking directly at HECO and comparable electric utilities, rather than HEI's cost of equity, has served to insulate HECO's ratepayers from any impact due to changes in HEI's cost of equity." (Thomas report, page 131)

3) " . . . diversification has not permanently raised or lowered the cost of capital incorporated into the rates that the utility's customers pay." (Thomas Report, page 121)

Q. Did the Commission adopt the Thomas Report?

A. Yes. The Commission adopted the Thomas Report in D&O No. 15225. In its D&O, the Commission also adopted the Department of Defense's recommendation that in rate proceedings the Companies " . . . present comprehensive analysis of the impact that the holding company structure and investments in non-utility subsidiaries have on its cost of capital to the utility." However, the Commission stated that it " . . . will apply the recommendation on a case-by-case basis in the Utilities' respective rate cases." (emphasis added) As a result, it is the Companies' understanding that the Commission will determine whether a "comprehensive analysis of the impact that the holding company structure and investments in non-utility subsidiaries have" on the cost of capital of HECO should be done in this case.

Q. In previous rate cases, what have the Companies done to address the issue as to whether such a comprehensive analysis should be done?

A. MECO, HECO and HELCO retained Mr. William E. Avera to address the issue in each of the following rate cases: Docket No. 97-0346 (MECO 1999 Test Year), Docket No. 2006-0386 (HECO 2007 Test Year), Docket No. 04-0113 (HECO 2005 Test Year), Docket No. 05-0315 (HELCO 2006 Test Year), Docket No. 99-0207 (HELCO 2000 Test Year), and Docket No. 97-0420 (HELCO 1999 Test Year). Mr. Avera was the Team Leader for Dennis Thomas and Associates with respect to those sections of the Thomas Report addressing cost of capital issues (including financial integrity and credit ratings). Mr. Avera's team assembled the material for Chapter 6 – Availability and Cost of Capital to HECO.

Q. What was Mr. Avera's conclusion?

A. Mr. Avera's conclusion is stated in each of his affidavits dated December 28, 1997 (see MECO-1610 in Docket No. 97-0346), March 1, 1998 (see HELCO-

1610 in Docket No. 97-0420), October 7, 1999 (see HELCO-1710 in Docket No. 99-0207), November 8, 2004 (see HECO-2118 in Docket No. 04-0113), May 1, 2006 (see HELCO-1820 in Docket No. 05-0315), and December 18, 2006 (see HECO-1916 in Docket No. 2006-0386). In summary, through evaluations that focused primarily on events since the Thomas report was issued in January 1995, Mr. Avera arrived at the following conclusion:

> "In conclusion, my review revealed no evidence that would alter the conclusions reached in the Thomas Report or indicate a fundamental change in investors' perceptions of the relationship between HEI and HECO. The comprehensive analyses conducted in preparing the Thomas Report required almost an entire year to complete and involved an exhaustive review of documents and extensive interviews with members of the investment community in Hawaii, on Wall Street, and in other financial centers. Given that the findings of such a comprehensive review with respect to the availability and cost of capital to HEI and its utility subsidiaries would not be expected to be materially different from those adopted by the PUC in December 1996, it is my opinion that the significant expenditure of time and money involved in conducting such a comprehensive review is not presently warranted."

Q. Did HECO, MECO and HELCO agree with Mr. Avera's conclusions?

A. Yes. A "comprehensive" analysis, such as that done as part of the Thomas Report, was not conducted in connection with the HECO, MECO and HELCO rate cases.

Q. Did the Commission require that a comprehensive analysis be conducted in any of those cases?

A. None was required in the MECO 1999 test year case, HECO 2005 test year rate case, or the HELCO 2000 test year case. The HELCO test year 1999 rate case was withdrawn in 1999.

Q. What has MECO done to address the issue as to whether such a comprehensive analysis should be done in this case?

A. MECO has again retained Mr. Avera.

Q. What is Mr. Avera's current conclusion?

A. Mr. Avera's conclusion is stated in his affidavit, a copy of which is attached as MECO-1720. After conducting an evaluation that focused primarily on events since his last review in 1999, Mr. Avera concluded the same as in his past three affidavits – in part, "my review revealed no evidence that would alter the conclusions reached in the Thomas Report," and "a comprehensive review is not presently warranted."

Q. Does MECO agree with Mr. Avera's current conclusion?

A. Yes. A "comprehensive" analysis, such as that done as part of the Thomas Report, is not warranted in this case.

SAVINGS FROM REVENUE BONDS

Q. H.R.S. Section 39A-208(b) requires that the Commission, in every rate case, make estimates of the savings to MECO's customers resulting from the use of special purpose revenue bonds. Have you prepared such an estimate for the Commission?

A. Yes. The savings estimate, along with an explanation of the savings calculation, is shown in MECO-1721.

CONCLUSION

Q. What is your conclusion regarding the fair rate of return on rate base for test year 2007?

A. The rate of return on rate base found fair and reasonable by the Commission should not be less than its composite cost of capital, and that the Company's composite cost of capital in test year 2007 is expected to be 8.98%. The 8.98% composite cost of capital includes a rate of return on common equity of 11.25%, which is important to the maintenance of the Company's credit quality.

Q. Does this conclude your testimony?

A. Yes, it does.

TAYNE S. Y. SEKIMURA

EDUCATIONAL BACKGROUND AND EXPERIENCE

Present employer:	Hawaiian Electric Company, Inc. 900 Richards Street Honolulu, HI 96813
Current position:	Financial Vice President
Previous positions:	Director, Corporate and Property Accounting Director, Internal Audit Capital Budgets Administrator
Years of service:	15 years
Other experience:	Audit Manager, KPMG Assistant Controller, Long Distance/USA
Certification:	Certified Public Accountant (not in public practice) State of Hawaii
Education:	University of Hawaii at Manoa Bachelor of Business Administration in Accounting
Previous Testimonies:	Maui Electric Company, Ltd Docket No. 94-0345 – Rate Base Hawaii Electric Light Company, Inc. Docket No. 94-0140 – Rate Base Hawaii Electric Light Company, Inc. Docket No. 05-0315 – Cost of Capital Hawaiian Electric Company, Inc. Docket No. 04-0113 – Depreciation Expense and Accumulated Depreciation; Total Average Number of Employees; King Street Office Building Lease; Prepaid Pension Asset; Gains on Sale of Land and Iolani Court Plaza Lease Premium; Accounting for Computer Software Development Costs; Abandoned Capital Project Costs; Maintaining Financial Integrity

Maui Electric Company, Ltd.

Composite Embedded Cost of Capital
Test Year 2007 Average
($ Thousands)

		(A)	(B) = (A)/Total(A)	(C)	(D) = (B)*(C)
		Capitalization			
	WP Series Reference	Amount	Percent of Total	Earnings Requirement	Weighted Earnings Requirements
Short-Term Debt	WP-1702	$ 4,750	1.27%	5.00%	0.06%
Long-Term Debt	WP-1703	150,585	40.15%	6.11%	2.45%
Hybrid Securities	WP-1704	9,192	2.45%	7.47%	0.18%
Preferred Stock	WP-1705	4,693	1.25%	8.34%	0.10%
Common Equity	WP-1706	205,882	54.89%	11.25%	6.17%
Total Capitalization		$ 375,101	100.00%		8.98%
Estimated 2007 Test Year Composite Cost of Capital					**8.98%**

Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.

Short-Term Borrowings
Test Year 2007 Average
($ Thousands)

	WP Reference	Total	
Short-Term Borrowings as of December 31, 2005	WP-1702, p.1	$ (5,250)	
2006 Estimated Net Change in Short-Term Borrowings	MECO-1707	20,000	
Short-Term Borrowings as of December 31, 2006		14,750	(A)
2007 Estimated Net Change in Short-Term Borrowings	MECO-1707	(20,000)	
Short-Term Borrowings as of December 31, 2007		$ (5,250)	(B)
Test Year 2007 Average = [(A)+(B)]/2		**$ 4,750**	
Earnings Requirement		5.00%	
Annual Debt Requirement		**$ 238**	

Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.

Embedded Cost of Long-Term Debt
Test Year 2007 Average
($ Thousands)

	(A)	(B)	(C) = (A)*(B)	(D) = WP-1703, p.2	(E)	(F) = (C)+(D)+(E)
Long-Term Debt	Rate	Net Proceeds	Annual Interest	Annual Amortization	Annual Insurance Premium	Annual Requirement
Special Purpose Revenue Bonds (Refunded Issue):						
Series 1993	5.45%	$ 30,000	$ 1,635	$ 50		$ 1,685
Series 1996A	6.20%	20,000	1,240	32		1,272
Series 1996B	5 7/8%	35,000	2,056	19	32 [A]	2,107
Series 1997A	5.65%	20,000	1,130	16	18 [B]	1,164
Refunding Series 1998A (1987)	4.95%	7,720	382	35		417
Refunding Series 1999B (1988)	5.75%	9,000	518	35		553
Refunding Series 1999D (1990A)	6.15%	1,000	62	3		65
Refunding Series 2000 (1990B&C)	5.70%	20,000	1,140	73		1,213
Refunding Series 2005A (1995A)	4.80%	2,000	96	7		103
Series 2007 (new issue)	5.50%	10,000 [C]	550	13		563
1992 (Redeemed)		n/a		16		16
		154,720	8,808	300	50	9,158
Unamortized Costs, Revenue Bonds *		(4,068)				
Unamortized Costs, First Mtg Bonds **		(46)		31		31
Unamortized Costs, SCF ***		(21)		6		6
Test Year 2007 Average		**$ 150,585**	**$ 8,808**	**$ 336**	**$ 50**	**$ 9,194**
Effective Rate = Total(F)/Total(B)						**6.11%**

* Issuance costs, redemption costs, issuance discounts, and investment income differentials are included in this amount. Refer to WP-1703, p.1 for detail.

** Unamortized costs relate to MECO's First Mortgage Bonds which were redeemed prior to December 31, 2005. Refer to WP-1703, p.8 for First Mortgage Bonds unamortized costs.

*** Unamortized costs relate to MECO's share of the issuance costs for the Multi-year Syndicated Credit Facility (SCF) pending PUC approval in Docket No. 2006-0360 (filed August 30, 2006). Refer to WP-1703, p. 9 for SCF issuance costs.

[A] Based on 9 basis points annually of outstanding par beginning in 2006.
[B] Based on 9 basis points annually of outstanding par beginning in 2007.
[C] Based on average balance at 12/31/06 of $0 and 12/31/07 of $20,000.

Note: Depending on market factors, MECO may refinance the Series 1996A and 1996B revenue bonds; however, these refinancings are not currently reflected in the long-term debt cost. An application for the approval to refinance the 1996A and 1996B series was filed with the Commission (Docket No. 2006-0383). The Commission issued Decision and Order No. 23100 (December 4, 2006) and Decision and Order No. 23161 (December 27,2006) authorizing the refinancings. If the Company refinances these revenue bonds, the refinancings will be reflected in the cost of capital at the earliest opportunity.

Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.

Embedded Cost of Hybrid Securities
Test Year 2007 Average
($ Thousands)

	(A)	(B)		(C) = (A)*(B)	(D)	(E) = (C)+(D)
Hybrid Security	Rate/ Return	2007 Test Year Average		Interest Expense	Annual Amortization	Annual Requirement
Series 2004	6.50%	$ 10,000	*	$ 650		$ 650
Unamortized Issuance Costs **		(808)			$ 36	36
Test Year 2007 Average		**$ 9,192**		**$ 650**	**$ 36**	**$ 686**
Effective Rate = Total(F)/Total(B)						**7.47%**

* Based on average balance at 12/31/06 of $10,000 and 12/31/07 of $10,000.

** Includes unamortized issuance costs of current and previously redeemed hybrid securities. Refer to MECO-WP-1704, p.1.

Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.

Embedded Cost of Preferred Stock
Test Year 2007 Average
($ Thousands)

	(A)	(B)	(C) = (A)*(B)	(D)	(E) = (C)+(D)
Preferred Stock	Rate	2007 Test Year Average	Annual Dividends	Annual Amortization	Annual Requirement
Perpetual Series *:					
Series H	7 5/8%	5,000	381	-	381
		5,000	381	0	381
Unamortized Costs **		(307)		10	10
Test Year 2007 Average		**$ 4,693**	**$ 381**	**$ 10**	**$ 391**
Effective Rate = Total(E)/Total(C)					**8.34%**

* Represents preferred stock not subject to mandatory redemption. Therefore, issuance costs are not amortized.

** Refer to WP-1705, p.1 for detail.

Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.

Common Equity
2007 Average
($ Thousands)

	WP Reference		BOOK Total	Adjustments for Ratemaking	RATEMAKING Total
Book Common Equity as of December 31, 2005	WP-1706, p.1		$ 194,190		$ 194,190
Restoration	WP-1706 p.2		-	90	90
Common Equity Investment as of December 31, 2005			194,190		194,281
2006 Estimated Net Change in Retained Earnings	MECO-1707		7,632		7,632
2006 Est Net AOCI adj related to Pension, net of tax			(14,521)	14,521	-
2006 Est Net AOCI adj related to OPEB, net of tax			(3,172)	3,172	-
2006 Est Net AOCI adj related to Exec Life, net of tax			169	(169)	-
Common Equity as of December 31, 2006		(A)	184,298		201,913
2007 Estimated Net Change in Retained Earnings	MECO-1707		7,939		7,939
2007 Est Net AOCI adj related to Pension, net of tax			(1,076)	1,076	-
2007 Est Net AOCI adj related to OPEB, net of tax			(68)	68	-
2007 Est Net AOCI adj related to Exec Life, net of tax			54	(54)	-
Common Equity as of December 31, 2007		(B)	$ 191,147		$ 209,852
Test Year 2007 Average = [(A)+(B)]/2					**$ 205,882**
Book 2007 Average = [(A)+(B)]/2			$ 187,723		

Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.

Sources and Applications of Funds
($ Thousands)

	Recorded 2005	Forecast 2006	Forecast 2007
Application of Funds:			
Capital Expenditures	$ 43,804	$ 61,720	$ 36,038
Less: CIAC & Advances	7,437	4,945	5,358
Less: AFUDC	1,291	3,170	1,236
Net Capital Expenditures	$ 35,076	$ 53,605	$ 29,444
Debt Redemption	$ -	$ -	$ -
Hybrid Redemption	-	-	-
Total Applications	$ 35,076	$ 53,605	$ 29,444
Sources of Funds:			
Internal Sources:			
Retained Earnings	$ 4,777	$ 7,632	$ 7,939
Depreciation & Amortization	28,223	30,278	33,118
Deferred Taxes & ITC	4,309	(584)	(1,865)
Other (Misc. Net Changes in Working Capital)	(4,733)	(8,971)	(7,748)
Total Internal Sources	$ 32,576	$ 28,355	$ 31,444
External Sources:			
Increase (Decrease) in Short-Term Borrowings	$ -	$ 20,000	$ (20,000)
Drawdown of Revenue Bond Proceeds	-	-	20,000
Temporary Investments	2,500	5,250	(2,000)
Total External Financing	$ 2,500	$ 25,250	$ (2,000)
Total Sources	$ 35,076	$ 53,605	$ 29,444

Totals may not add exactly due to rounding.

RESEARCH

Key Credit Factors:

Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers

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The methodology that Standard & Poor's Ratings Services uses to rate vertically integrated electric, gas, and combination investor-owned utilities in the U.S. is based on the same precepts that we have used for many years, though the emphasis has changed as the utility industry has evolved. The fundamental methodology encompasses two basic components--business risk and financial risk--and their relationship. Where a utility presents a strong business risk profile, the financial profile can be less robust for any given rating. Likewise, where a utility's business risk profile is weaker, its financial performance must be stronger for any given rating. For combination utilities, the gas operations may have a stabilizing influence on credit quality, but since the electric business is typically significantly larger, it is the major credit driver. (For details on Standard & Poor's analytical approach to gas utilities, see "Key Credit Factors For Natural Gas Distributors" published Feb. 28, 2006.)

Often, an integrated utility is a part of a larger holding company structure that also owns other businesses, frequently unregulated electricity generation. This fact does not alter how we analyze the utility, but it may affect the ultimate rating outcome due to any credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Five Factors Determine The Business Profile

Five basic characteristics define a vertically integrated utility's business profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Standard & Poor's is most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations. While considerable attention has focused in recent years on companies in states that deregulated in the late 1990s and the early part of this decade and the related credit consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

On Standard & Poor's business profile scale (where '1' is excellent and '10' is vulnerable), vertically integrated utilities generally have satisfactory business profiles of '5' or '6'. (See tables 1 and 2 in the Appendix below for business profile benchmarks plus a list of utilities we rate and their business profile scores.) We view a company that owns regulated generation, transmission, and distribution operations, as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management.

Regulation

Regulation is a critical aspect that underlies integrated utilities' creditworthiness. Decisions by state public service commissions can profoundly affect financial performance. Standard & Poor's assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program and incurs substantial deferrals of fuel costs.

Standard & Poor's evaluation encompasses the administrative, judicial, and legislative processes involved in state and federal regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case-by-case with regard to the potential effect on credit quality. As frequently postulated in prior years, our evaluation of regulation focuses on the willingness and ability of regulation to provide cash flow and earnings quality adequate to meet investment needs, earnings stability through timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity. Regulators' authorization of high rates of return is of little value unless returns are realistic and achievable. Allowing high returns based on noncash items does not benefit bondholders. A regulatory jurisdiction that permits incentives whereby utilities are allowed to earn a return based on their ability to sustain rates at competitive levels is viewed favorably. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Also important is the ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses or with fixed-fuel mechanisms, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. Standard & Poor's notes that fuel-adjustment mechanisms have become more common in the industry, but not all are created equal. While some jurisdictions permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions, such as Washington State, impose a deadband in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. In Arizona, Arizona Public Service Co. has a 90/10 sharing mechanism between the company and ratepayers, respectively, for all costs passed through the power supply adjuster. The mechanism is triggered based on a date (once a year in February 2006) and not on a threshold level of deferrals. The annual adjustment is also subject to a lifetime cap of 4 mils per kilowatt-hour, which has led to power deferrals.

In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes significant cash flow drain and reduces the utility's need to issue debt during construction.

Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery. Also supportive of credit quality is the ability of the utility, commission staff,

consumer advocates, and other major interveners to reach a comprehensive settlement before construction of new base load capacity. Certain states, such as Indiana, Texas, Kansas, and Minnesota, have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with environmental compliance equipment without having to file a formal rate case. Creditworthiness can also be enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing storm damage, as in Florida. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, it has shown a willingness to work with utilities to help them recover at least some of these costs on a timely basis and to start replenishing storm reserves. Finally, the greater the percentage of a utility's rates that are recovered through fixed charges rather than volume-based charges, the greater the support for credit quality.

For utilities that own a natural gas business, automatic and timely pass-through of commodity costs provides the strongest level of credit support. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels.

Due to the extreme volatility and high gas prices over the past few heating seasons, more regulators have revised gas adjustment clauses to provide monthly gas adjustments rather than awaiting the end of the heating season to begin reimbursement. This expedited treatment helps the utility to reduce any regulatory lag to recover costs and streamlines working capital needs, which in turn should allow the firm to modestly temper rising gas bills to their customers.

Both regulators and natural gas companies are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and companies are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting the company's bottom line and still allow utilities to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Key success factors include:

- Alternative ratemaking/flexibility,
- Attention to credit quality,
- Timely and consistent rate treatment,
- Support for fuel cost recovery,
- Support for a reasonable cash return on investment, and
- Support for rapid return on investment.

Markets

Assessing market dynamics begins with an economic and demographic evaluation of the service area in which a utility operates. Strength of long-term demand for energy is examined from a macroeconomic perspective, which enables Standard & Poor's to measure the affordability of rates and the staying power of demand. Distribution by classification according to total number of customers, revenues, and margins is closely scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed with some caution because the utility may be exposed to cyclical volatility and face competitive alternatives. A large residential component, on the other hand, produces a more stable and predictable revenue stream. The utility's largest customers are identified to determine their stability and importance to the bottom line because the loss of one large customer could adversely affect the utility's financial position. Moreover, large customers may turn to self-generation, potentially leading to less financial protection for the utility.

Standard & Poor's also analyzes any long-term consumption trends and the reasons behind them. Factors addressed include the market's size and growth rate, the franchise's strength, historical and projected growth rates, income levels and trends in population, employment, and per capita income. A utility with a

healthy economy and customer base, as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment, will be better able to support its operations.

For the gas business, Standard & Poor's also examines customer saturation. Firms that operate in service areas with low growth potential still can expand at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to companies operating in low population growth service areas.

Despite the review of market characteristics, they are clearly a secondary consideration to regulation. In Nevada, for years the country's fastest growing state, Nevada Power Co. and Sierra Pacific Power Co. struggled to recover capital expenditures on a timely basis, and were accordingly rated as low investment-grade credits. In Florida, which has competed with Nevada for years in its pace of growth, the Florida Public Service Commission established polices of quick recovery of capital investments and, on a stand-alone basis, the state's utilities' credit metrics have remained strong.

Critical success factors include:

- A healthy and growing economy,
- Growth in population and number of customers,
- An attractive business environment, and
- An above-average residential base.

Operations

Standard & Poor's focuses on cost, reliability, safety, and quality of service when assessing a utility's operations. Management is always under pressure to optimize the use of resources, and if it is not cost-effective in meeting service standards and reliability, regulatory or competitive pressures are likely to increase. Consequently, Standard & Poor's emphasizes areas that require heightened and ongoing management attention, in the absence of which political, regulatory, or competitive problems are likely to arise.

The status of utility plant investment is reviewed with regard to generating station availability, efficiency, and utilization, as well as for compliance with existing and potential environmental and other regulatory standards. The record of plant outages, system losses, equivalent availability, load factors, heat rates, and capacity factors are examined. Important considerations include the projected capital improvements and plant additions necessary to provide high-quality, reliable service. The general condition of the assets and how well such assets are maintained are also important considerations.

Emphasis is placed on reserve margins, fuel mix, fuel contract terms, purchased-power arrangements, and system operators. Moreover, the quality and concentration of capacity is just as important as the size of reserves. Standard & Poor's recognizes that reserve requirements differ among companies, depending upon individual operating and load characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to switch generating sources to take advantage of cheaper fuels is viewed favorably. Dependence on any single fuel, or asset concentration in one or two large generating stations, can cause significant swings in a company's financial performance. Similarly, utilities that rely on nuclear generation receive an elevated degree of attention due to the scale, technical complexity, and politically sensitive nature of nuclear facilities. Indeed, the sound operation of nuclear units can define a utility's operational risk profile and its ability to achieve projected financial results. Standard & Poor's seeks to distinguish between those operators that have exhibited sound and stable operational performance, and the likelihood that it will continue, and those whose nuclear operations are vulnerable to problems that may impair financial results.

But having a large concentration of capacity based on fossil fuels also imposes certain risks. Coal-fired capacity is burdened with increased environmental costs related to reducing sulfur dioxide, nitrogen oxide,

mercury, and eventually carbon dioxide emissions. Gas-fired capacity presents its own challenges, particularly the extreme volatility and significant increase in gas prices over the past few years. Buying power may be a more appropriate option for a utility than new plant construction because the utility avoids construction costs and the financial risks posed by regulatory lag when seeking recovery of costs. Purchasing power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Despite these benefits, such a strategy does commit the utility to a fixed obligation, which Standard & Poor's captures analytically through certain adjustments to financial statements. We calculate the net present value of future annual capacity payments (discounted at the company's cost of debt) over the life of the contract. Standard & Poor's then applies a risk factor against this value and adds the result to the utility's balance sheet. The risk factor is largely a function of the strength of the regulatory recovery mechanisms established to address procurement costs.

Other operational characteristics that will support an above-average evaluation for vertically integrated companies are assets that are in good physical condition and are well maintained. In addition, capital expenditures for necessary system improvements must be at manageable levels, yet sufficient to provide for constant renewal and refurbishment of the system. Operating performance, reliability statistics (such as outage duration and frequency), and efficiency measures are expected to meet industry and regional averages. Having interconnections that provide access to low-cost and diverse power supply sources is viewed favorably, as is limited environmental exposure.

For a gas company, drawing from a single interstate pipeline or relying on a particular gas basin exposes it to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects the utility from such disruptions. Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. Gas distributors benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Outdated systems requiring extensive maintenance and capital expenditures lower profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, operational efficiencies can be obtained through the use of new technology.

Critical success factors include:

- Well-maintained assets,
- Solid plant performance,
- Fuel diversity,
- Adequate generating reserves, and
- Compliance with environmental standards.

Competitiveness

For vertically integrated utilities, competitive factors include percentage of firm wholesale revenues that are most vulnerable to competition, industrial load, and revenue concentrations, particularly in energy intensive industries; exposure of key customers to alternative suppliers; commercial concentrations; rates charged to various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Electricity competes with other fuels--particularly natural gas--for certain segments of the market like space heating, water heating, and cooking. Thus, high electricity prices, which can be attributed to inefficient operations, are cause for concern if customers have access to alternative energy sources. Self-generation has been a risk, as large commercial and industrial customers may take advantage of cogeneration technologies to reduce their reliance on, and in some cases to disconnect from the system. In the future, technology could pose a greater threat. Bypass risk, too, may grow if distributed generation, microgeneration, and self-generation prove more economically attractive for smaller customers.

Due to their proximity to interstate gas pipelines, some large customers can directly tie into a transmission

line and completely bypass gas distributors' services. Although such pipelines provide key sources of gas supply for these companies, it is important to recognize this bypass risk. Ideally located gas companies have adequate transmission access but have industrial customers far from interstate pipelines.

Critical success factors include:

- Low cost structure,
- Limited bypass risk, and
- Management's commitment to lowering costs.

Management

Evaluating management is of paramount importance to Standard & Poor's analysis because management decisions affect all areas of a company's operations and financial health. Although regulation, the economy, and other outside factors certainly influence results, the quality of management ultimately determines a company's success. Standard & Poor's private meetings with senior management significantly augment the public record in the effort to appraise management. Meetings are very useful for the candid interpretation of recent developments and, importantly, to provide executives with a forum for the presentation of goals, objectives, and strategies.

Management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple--and often incompatible--priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

Standard & Poor's also focuses on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

In addition, a company's accounting and financing practices are critical to Standard & Poor's analysis. For example, proactive management will likely adopt accounting practices that are more appropriate in a competitive environment such as higher depreciation rates for electric generation equipment. Large, growing cost deferrals or regulatory assets are viewed more negatively. Management can enhance its financial condition by taking any number of discretionary actions, such as selling common equity, reducing the common dividend payout, and deleveraging. A utility's management will also be evaluated on cost-cutting ability and creativity in entering into strategic alliances that improve efficiency.

Strong corporate governance, reflected in active, independent board of directors that participate in determining and monitoring corporate controls, help to support management's credibility and corporate financial disclosure. If it is evident that a company's board is passive and does not exercise proper oversight, it weakens the checks and balances of the organization and may detract from credit quality. Included in Standard & Poor's review of corporate governance is the proportion of independent directors on the board, the breadth and depth of the directors' experience, the proportion of independent directors on the board's audit committee, and directors' compensation.

Some vertically integrated utilities have felt compelled to invest outside their traditional businesses to increase earnings, especially as stock prices have underperformed market indices. Participation in higher-risk, unregulated activities such as merchant generation, exploration and development, gathering and processing, or marketing and trading can significantly detract from the consolidated entity's credit profile. In this regard, credit ratings are not based on the regulated business only, but on the qualitative and quantitative fundamentals of the consolidated entity. Standard & Poor's considers the ratings of the regulated businesses as being less vulnerable to the negative credit influence of other affiliates and holding company activities, as relevant, where very strong structural and/or regulatory insulation exists, which tends to be more the exception than the rule.

Critical success factors include:

- Commitment to credit quality,
- Credibility,
- Strong corporate governance, and
- Conservative financial policies, especially regarding nonregulated activities, if relevant.

Effect On Ratings

In summary, Standard & Poor's examines the key business risk drivers for vertically integrated utilities--regulation, markets, operations, competitiveness, and management--in conjunction with financial measures when assigning credit ratings. The credit quality of most vertically integrated utilities is solidly investment grade. This is a primarily a function of the existence of regulation. As discussed above, the factors that further differentiate ratings among this sector include their markets, operational track record, competitive posture, and management's risk appetite. Vertically integrated utilities generally have satisfactory business risk profile scores, with only a few having strong or weak business positions.

Appendix

Table 1

Industry Benchmarks

Business Profile	AA		A		BBB		BB	
Adjusted FFO interest coverage (x)								
1	3.0	2.5	2.5	1.5	1.5	1.0	< 1.0	< 1.0
2	4.0	3.0	3.0	2.0	2.0	1.0	< 1.0	< 1.0
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1.0
4	5.0	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6.0	5.2	5.2	4.2	4.2	3.0	3.0	2.0
7	8.0	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10.0	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9	N/A	N/A	10.0	7.0	7.0	4.0	4.0	2.8
10	N/A	N/A	11.0	8.0	8.0	5.0	5.0	3.0
Adjusted FFO/average total debt (%)								
1	20.0	15.0	15.0	10.0	10.0	5.0	< 5.0	< 5.0
2	25.0	20.0	20.0	12.0	12.0	8.0	< 8.0	< 8.0
3	30.0	25.0	25.0	15.0	15.0	10.0	10.0	5.0
4	35.0	28.0	28.0	20.0	20.0	12.0	12.0	8.0
5	40.0	30.0	30.0	22.0	22.0	15.0	15.0	10.0
6	45.0	35.0	35.0	28.0	28.0	18.0	18.0	12.0
7	55.0	45.0	45.0	30.0	30.0	20.0	20.0	15.0
8	70.0	55.0	55.0	40.0	40.0	25.0	25.0	15.0
9	N/A	N/A	65.0	45.0	45.0	30.0	30.0	20.0
10	N/A	N/A	70.0	55.0	55.0	40.0	40.0	25.0
Adjusted total debt/total capital (%)								
1	48.0	55.0	55.0	60.0	60.0	70.0	> 70.0	> 70.0
2	45.0	52.0	52.0	58.0	58.0	68.0	> 68.0	> 68.0
3	42.0	50.0	50.0	55.0	55.0	65.0	65.0	70.0
4	38.0	45.0	45.0	52.0	52.0	62.0	62.0	68.0
5	35.0	42.0	42.0	50.0	50.0	60.0	60.0	65.0
6	32.0	40.0	40.0	48.0	48.0	58.0	58.0	62.0
7	30.0	38.0	38.0	45.0	45.0	55.0	55.0	60.0
8	25.0	35.0	35.0	42.0	42.0	52.0	52.0	58.0
9	N/A	N/A	32.0	40.0	40.0	50.0	50.0	55.0

10	N/A	N/A	25.0	35.0	35.0	48.0	48.0	52.0

Note: Business profile scores are characterized from '1' (excellent) to '10' (weak). FFO–Funds from operations. N/A–Not applicable.

Table 2

Vertically Integrated Utilities

Company	Corporate credit rating	Business profile score
Aquila Inc.	B/CW-Pos/B-2	8
AGL Resources Inc.	A-/Negative/A-2	4
Alabama Power Co.	A/Stable/A-1	4
ALLETE Inc.	BBB+/Stable/A-2	5
Ameren Corp.	BBB+/CW-Neg/A-2	6
Appalachian Power Co.	BBB/Stable/--	5
Arizona Public Service Co.	BBB-/Stable/A-3	6
Atmos Energy Corp.	BBB/Stable/A-2	4
Black Hills Power Inc.	BBB-/Negative/--	6
Central Illinois Light Co.	BBB+/CW-Neg/--	7
Central Vermont Public Service Corp.	BB+/Stable/--	6
CILCORP Inc.	BBB+/CW-Neg/--	7
Cincinnati Gas & Electric Co.	BBB/Positive/A-2	6
Cleco Power LLC	BBB/Negative/--	6
Cleveland Electric Illuminating Co.	BBB/Stable/--	6
Consolidated Natural Gas Co.	BBB/Stable/A-2	6
Consumers Energy Co.	BB/Stable/--	6
Dayton Power & Light Co.	BB+/Positive/--	5
Detroit Edison Co.	BBB/Stable/A-2	6
Duke Power Co. LLC	BBB/Positive/A-2	4
El Paso Electric Co.	BBB/Stable/--	6
Empire District Electric Co.	BBB-/Stable/A-3	6
Energy East Corp.	BBB+/Negative/A-2	3
Enogex Inc.	BBB+/Stable/--	7
Entergy Arkansas Inc.	BBB/Negative/--	5
Entergy Gulf States Inc.	BBB/Negative/--	6
Entergy Louisiana LLC	BBB/Negative/--	5
Entergy Mississippi Inc.	BBB/Negative/--	6
Entergy New Orleans Inc.	D/--/--	8
Equitable Resources Inc.	A-/CW-Neg/A-2	8
Florida Power & Light Co.	A/CW-Neg/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Green Mountain Power Corp.	BBB/CW-Pos/--	5
Gulf Power Co.	A/Stable/--	4
Hawaiian Electric Co. Inc.	BBB+/Negative/A-2	5
IDACORP Inc.	BBB+/Negative/A-2	5
Idaho Power Co.	BBB+/Negative/A-2	5
Indiana Michigan Power Co.	BBB/Stable/--	6
Indianapolis Power & Light Co.	BB+/Positive/--	4
Interstate Power & Light Co.	BBB+/Stable/A-2	5
IPALCO Enterprises Inc.	BB+/Positive/--	4
Kansas City Power & Light Co.	BBB/Stable/A-2	6
Kansas Gas & Electric Co.	BB+/Positive/--	6
Kentucky Power Co.	BBB/Stable/--	5
Kentucky Utilities Co.	BBB+/Stable/A-2	5
Louisville Gas & Electric Co.	BBB+/Stable/--	5

Madison Gas & Electric Co.	AA-/Stable/A-1+	4
Michigan Consolidated Gas Co.	BBB/Stable/A-2	4
MidAmerican Energy Co.	A-/Stable/A-1	5
Mississippi Power Co.	A/Stable/A-1	4
Monongahela Power Co.	BB+/Positive/--	5
Montana-Dakota Utilities Co.	BBB+/Stable/--	6
National Fuel Gas Co.	BBB+/Stable/A-2	7
Nevada Power Co.	B+/Positive/--	6
New York State Electric & Gas Corp.	BBB+/Negative/A-2	3
NISource	BBB/Stable/--	4
Northern Indiana Public Service Co.	BBB/Stable/--	5
Northern States Power Co.	BBB/Stable/A-2	5
Northern States Power Wisconsin	BBB+/Stable/--	4
Ohio Edison Co.	BBB/Stable/A-2	6
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	5
Pacific Gas & Electric Co.	BBB/Stable/A-2	5
PacifiCorp	A-/Stable/A-1	5
Pennsylvania Power Co.	BBB/Stable/--	6
Pinnacle West Capital Corp.	BBB-/Stable/A-3	6
PNM Resources Inc.	BBB/Negative/A-3	6
Portland General Electric Co.	BBB+/Negative/A-2	5
Progress Energy Carolinas Inc.	BBB/PositiveA-2	5
Progress Energy Florida Inc.	BBB/Positive/A-2	4
PSI Energy Inc.	BBB/Positive/A-2	4
Public Service Co. of Colorado	BBB/Stable/A-2	4
Public Service Co. of New Hampshire	BBB/Stable/--	5
Public Service Co. of New Mexico	BBB/Negative/A-3	6
Public Service Co. of Oklahoma	BBB/Stable/--	5
Puget Energy Inc.	BBB-/Stable/--	4
Puget Sound Energy Inc.	BBB-/Stable/A-3	4
Questar Market Resources Inc.	BBB+/Stable/---	8
Rochester Gas & Electric Corp.	BBB+/Negative/--	3
San Diego Gas & Electric Co.	A/Stable/A-1	5
Savannah Electric & Power Co.	A/Stable/--	4
SCANA Corp.	A-/Stable/--	4
Sierra Pacific Power Co.	B+/Positive/--	6
Sierra Pacific Resources	B+/Positive/B-2	6
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
Southern California Edison Co.	BBB+/Stable/A-2	6
Southern Co.	A/Stable/A-1	4
Southern Indiana Gas & Electric Co.	A-/Stable/--	4
Southwestern Electric Power Co.	BBB/Stable/--	5
Southwestern Public Service Co.	BBB/Stable/A-2	5
System Energy Resources Inc.	BBB-/Negative/--	7
Tampa Electric Co.	BBB-/Stable/A-3	4
Toledo Edison Co.	BBB/Stable/--	6
Tucson Electric Power Co.	BB/Stable/B-2	8
TXU U.S. Holdings Co.	BBB-/Negative/--	8
Union Electric Co.	BBB+/CW-Neg/A-2	5
Union Light Heat & Power Co.	BBB/Positive/--	5
Vectren Utility Holdings Inc.	A-/Stable/A-2	3
Virginia Electric & Power Co.	BBB/Stable/A-2	5

Westar Energy Inc.	BB+/Positive/--	5
Wisconsin Electric Power Co.	A-/Negative/A-2	4
Wisconsin Energy Corp.	BBB+/Negative/A-2	5
Wisconsin Power & Light Co.	A-/Stable/A-2	4
Wisconsin Public Service Corp.	A+/CW-Neg/A-1	4
Xcel Energy Inc.	BBB/Stable/A-2	5

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Forward-Looking Statements

This report and other presentations made by Hawaiian Electric Industries, Inc. (HEI) and Hawaiian Electric Company, Inc. (HECO) and their subsidiaries contain "forward-looking statements," which include statements that are predictive in nature, depend upon or refer to future events or conditions, and usually include words such as "expects," "anticipates," "intends," "plans," "believes," "predicts," "estimates" or similar expressions. In addition, any statements concerning future financial performance, ongoing business strategies or prospects and possible future actions are also forward-looking statements. Forward-looking statements are based on current expectations and projections about future events and are subject to risks, uncertainties and the accuracy of assumptions concerning HEI and its subsidiaries (collectively, the Company), the performance of the industries in which they do business and economic and market factors, among other things. **These forward-looking statements are not guarantees of future performance.**

Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward-looking statements and from historical results include, but are not limited to, the following:

- the effects of international, national and local economic conditions, including the state of the Hawaii tourist and construction industries, the strength or weakness of the Hawaii and continental U.S. real estate markets (including the fair value of collateral underlying loans and mortgage-related securities) and decisions concerning the extent of the presence of the federal government and military in Hawaii;
- the effects of weather and natural disasters, such as hurricanes, earthquakes and tsunamis;
- global developments, including the effects of terrorist acts, the war on terrorism, continuing U.S. presence in Iraq and Afghanistan, potential conflict or crisis with North Korea and in the Middle East, North Korea's and Iran's nuclear activities and potential avian flu pandemic;
- the timing and extent of changes in interest rates and the shape of the yield curve;
- the risks inherent in changes in the value of and market for securities available for sale and pension and other retirement plan assets;
- changes in assumptions used to calculate retirement benefits costs and changes in funding requirements;
- increasing competition in the electric utility and banking industries (e.g., increased self-generation of electricity may have an adverse impact on HECO's revenues and increased price competition for deposits, or an outflow of deposits to alternative investments, may have an adverse impact on American Savings Bank, F.S.B.'s (ASB's) cost of funds);
- capacity and supply constraints or difficulties, especially if generating units (utility-owned or independent power producer (IPP)-owned) fail or measures such as demand-side management (DSM), distributed generation (DG), combined heat and power (CHP) or other firm capacity supply-side resources fall short of achieving their forecasted benefits or are otherwise insufficient to reduce or meet peak demand;
- increased risk to generation reliability as generation reserve margins on Oahu continued to be strained;
- fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses;
- the ability of IPPs to deliver the firm capacity anticipated in their power purchase agreements (PPAs);
- the ability of the electric utilities to negotiate, periodically, favorable fuel supply and collective bargaining agreements;
- new technological developments that could affect the operations and prospects of HEI and its subsidiaries (including HECO and its subsidiaries and ASB and its subsidiaries) or their competitors;
- federal, state and international governmental and regulatory actions, such as changes in laws, rules and regulations applicable to HEI, HECO and their subsidiaries (including changes in taxation, environmental laws and regulations and governmental fees and assessments); decisions by the Public Utilities Commission of the State of Hawaii (PUC) in rate cases and other proceedings and by other agencies and courts on land use, environmental and other permitting issues; required corrective actions, restrictions and penalties (that may arise with respect to environmental conditions, renewable portfolio standards (RPS), capital adequacy and business practices);
- increasing operations and maintenance expenses for the electric utilities and the possibility of more frequent rate cases;
- the risks associated with the geographic concentration of HEI's businesses;
- the effects of changes in accounting principles applicable to HEI, HECO and their subsidiaries, including the adoption of new accounting principles (such as the effects of Statement of Financial Accounting Standards (SFAS) No. 158 regarding employers' accounting for defined benefit pension and other postretirement plans), continued regulatory accounting under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and the possible effects of applying Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R, "Consolidation of Variable Interest Entities," and Emerging Issues Task Force Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease," to power purchase arrangements with independent power producers;
- the effects of changes by securities rating agencies in their ratings of the securities of HEI and HECO and the results of financing efforts;
- faster than expected loan prepayments that can cause an acceleration of the amortization of premiums on loans and investments and the impairment of mortgage servicing rights of ASB;
- changes in ASB's loan portfolio credit profile and asset quality which may increase or decrease the required level of allowance for loan losses;
- changes in ASB's deposit cost or mix which may have an adverse impact on ASB's cost of funds;
- the final outcome of tax positions taken by HEI, HECO and their subsidiaries;
- the ability of consolidated HEI to generate capital gains and utilize capital loss carryforwards on future tax returns;
- the risks of suffering losses and incurring liabilities that are uninsured; and
- other risks or uncertainties described elsewhere in this report and in other periodic reports (e.g., "Item 1A. Risk Factors" in the Company's Annual Report on Form 10-K) previously and subsequently filed by HEI and/or HECO with the Securities and Exchange Commission (SEC).

Forward-looking statements speak only as of the date of the report, presentation or filing in which they are made. Except to the extent required by the federal securities laws, HEI and its subsidiaries undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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RESEARCH

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Industry Report Card:

Few Rating Actions For U.S. Electric, Gas, And Water Utilities In Third Quarter

Publication date: 25-Oct-2006
Primary Credit Analyst: Richard W Cortright, Jr., New York (1) 212-438-7665; richard_cortright@standardandpoors.com

Commentary/Key Trends

The stable credit trend for the U.S. utility industry continued through the third quarter of 2006 as companies generally kept the focus on their core competencies. Standard & Poor's Ratings Services took few rating actions during the quarter, a trend that we expect to continue into the fourth quarter based on the outlook distribution throughout the utility industry. In addition, with a few notable exceptions, better relationships with regulators proved to be sustainable during the quarter.

Rating actions to date in 2006 on electric, gas, pipeline, and water utilities have moved in a very positive direction, with upgrades of 28 companies and downgrades of 14. This contrasts starkly with 2004 and 2005, when rating downgrades outpaced upgrades by about three to two.

Rating activity during the third quarter affected 12 companies, and was evenly divided between upgrades and downgrades. The principal drivers of upside rating actions were enhanced liquidity and overall stronger financial profiles, reduced business risk, and improved regulatory relationships. Negative rating actions (five of the six related to a single entity, PEPCO Holdings Inc.) were attributable to exceptionally difficult political environments, subpar financial parameters, and an increased focus on riskier unregulated ventures. The handful of new CreditWatch listings resulted from merger and acquisition announcements.

Perhaps the most notable events of the quarter were the dissolution of the merger agreement between Exelon Corp. and Public Service Enterprise Group Inc. (PSEG) and political developments in Illinois. The failure of the merger resulted fundamentally from the inability of the companies and New Jersey regulators to reach an accommodation on specific financial benefits to ratepayers. Standard & Poor's subsequently removed the ratings of Exelon and PSEG from CreditWatch with negative implications, but left the CreditWatch negative listing on Exelon unit Commonwealth Edison Co. because of the increasingly uncertain political environment in Illinois. This uncertainty quickly led to downgrades of all the state's electric utilities in early October, reflecting utilities' vulnerability to aggressive political initiatives. At the time of publication, the convening of a special session of the state legislature to consider extending for three years the current long-lived electric rate freeze for all the state's utilities was under serious consideration. Such legislation would result in a serious cash shortfall for the utilities because the costs they would incur to procure power would exceed the rates they are allowed to charge customers for that power. Because no lawmaker has thus far proposed any alternative mechanisms for recovery, the utilities' financial viability would be threatened in relatively short order.

Despite these specific developments, credit quality of the industry continues to be defined by the

emphasis on core competencies, where risks are more familiar, but can still be considerable. These risks include:

- Major pending regulatory decisions;
- The approaching end of lengthy rate freezes and industry transition periods in a few states;
- The need for substantial infrastructure expenditures; and
- Fuel cost recovery in a high-fuel-price environment.

In addition, event risk, specifically merger and acquisition activity, is likely to continue. Despite these challenges, more than one-half the utilities that Standard & Poor's rates carry a stable credit outlook because of the fundamentally sound business model of much of the industry, and reasonably solid financial performance.

The merchant power sector witnessed very limited rating activity in the third quarter. Standard & Poor's raised the ratings on Mission Energy Holding Co. one notch to 'B' and its subsidiaries one notch to 'BB-' to reflect the tighter relationship of the companies' credit quality to that of parent Edison International in light of expected but unspecified capital contributions over time by the parent. Otherwise, the only rating action was the placement of the 'B+' rating of Mirant Corp. and its rated subsidiaries on CreditWatch with negative implications after the company announced that it would sell its Asian and Caribbean assets and use the proceeds to buy back stock. Generally, Standard & Poor's expects that a general consolidation of the merchant sector will result despite the earlier failure of the proposed NRG Energy Inc. and Mirant merger.

Chart 1

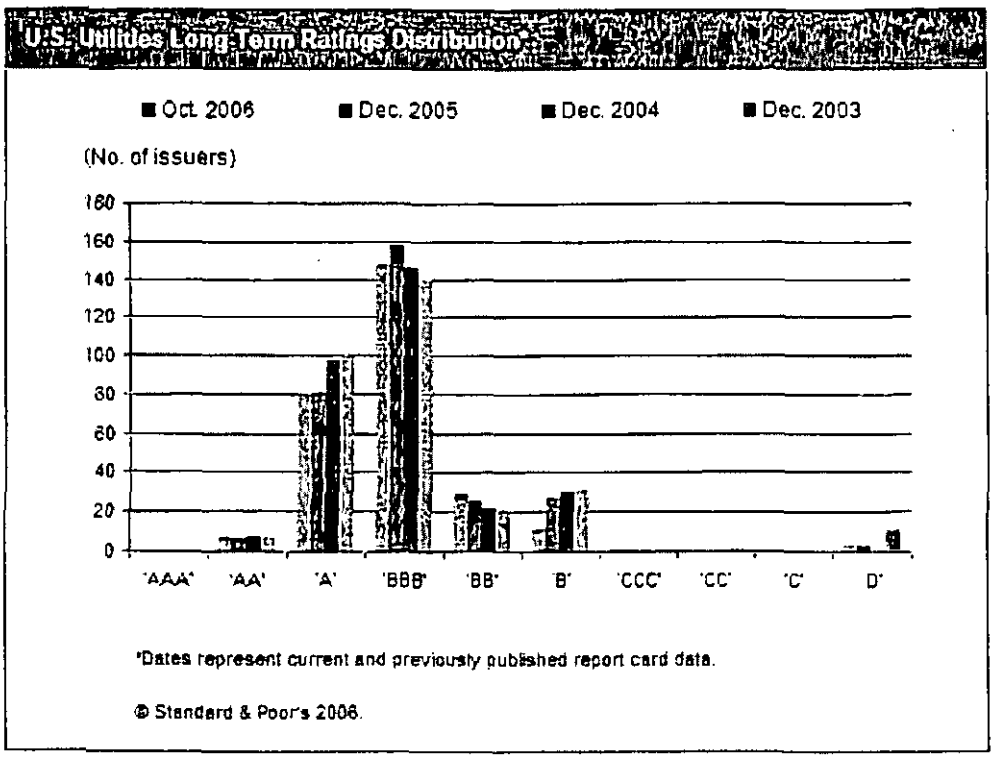
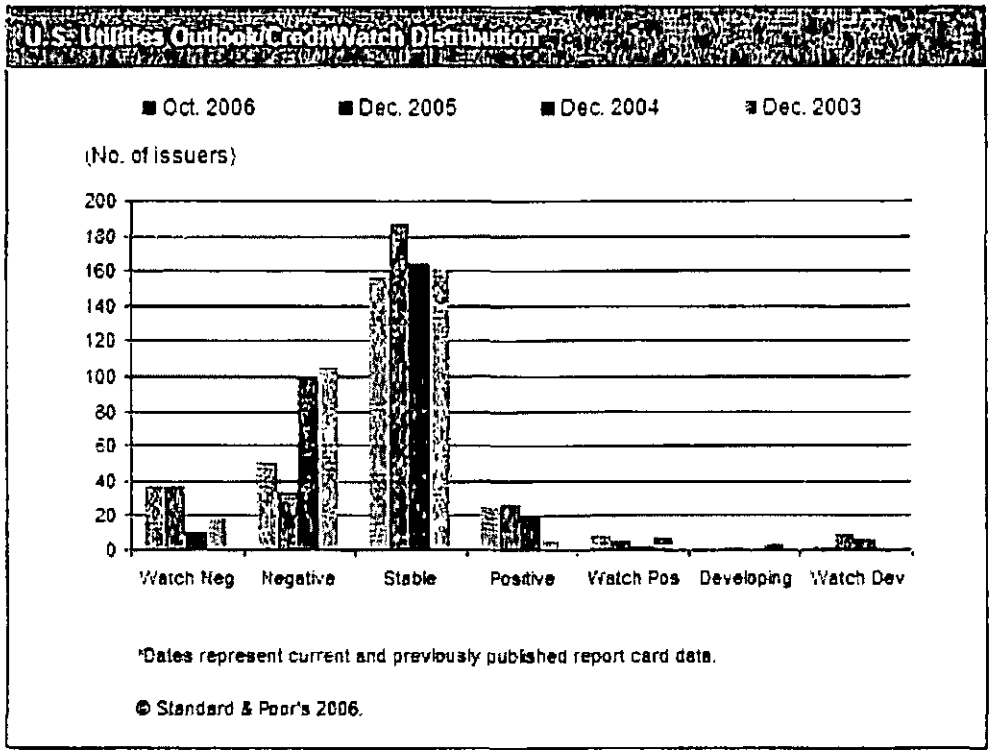


Chart 2



Issuer Review

Table 1

Company/Corporate credit rating*/Comments	Analyst
AEP Texas Central Co. (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
AEP Texas North Co (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
AES Corp. (The) *(BB-/Stable/--)*	
We expect AES to continue to reduce parent-level debt, but also expect that deleveraging pace will slow. Financial metrics improved to 56% by mid-year 2006 and will trend modestly lower by year-end. AES's funding requirements for new projects remains large. We expect continued strong cash flows from the U.S. subsidiaries Indianapolis Power & Light Co. and AES Eastern Energy LLC to fund some projects, but issuing new debt will be needed. Monetization of some existing projects will fund large investments in alternate renewable energy. Liquidity has	Aneesh Prabhu

improved largely because AES Eastern now has its own financing arrangements for hedging purposes and does not rely on parent AES.

AGL Resources Inc. (A-/Negative/A-2)

In August 2006, the Louisiana Department of Natural Resources notified AGL that is was suspending the company's mineral lease at the Jefferson Island Storage & Hub facility site. The suspension stalls and potentially could terminate AGL's planned 12 billion cubic feet expansion of salt dome natural gas storage capacity. Although now the subject of a legal dispute, the mineral lease suspension is credit neutral because it reduces capital spending requirements in 2006 and any incremental cash flow from the expansion would take a few years to realize. As of June 30, 2006, AGL's adjusted funds from operations to interest coverage was about 4x and adjusted FFO to average total debt was about 18x for the prior 12 months.	Michael Messer

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Alabama Gas Corp. (BBB+/Stable/--)

See Energy East Corp.	Todd Shipman

Alabama Power Co. (A/Stable/A-1)

See Southern Co.	Terry Pratt

Allegheny Energy Inc. (BB+/Positive/--)

The company continues to make progress in restoring its financial profile through debt reduction and refinancing. Cash flow in second-half 2006 will improve from higher provider-of-last-resort rates, participation as a generation supplier in auction markets, and from the transition to market-based rates in the deregulated sector of its business, but will be also tempered by higher coal costs. Lingering operational issues remain, including a transformer failure that caused a generation unit outage in the third quarter. A $100 million rate case decision pending in West Virginia is important to credit quality. A significant increase in environmental compliance costs at the Fort Martin and Hatsfield Ferry (a second time) plants will slow deleveraging, but is not expected to pose an immediate challenge.	Aneesh Prabhu

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Allegheny Energy Supply Co. LLC (BB+/Positive/--)

See Allegheny Energy Inc.	Aneesh Prabhu

ALLETE Inc. (BBB+/Stable/A-2)

Cash flow protection measures have rebounded after dipping considerably in 2005 due to a one-time $77 million cash payment related to the transfer of the Kendall County power contract in first-half 2005. At 18%, adjusted FFO to debt for the 12 months ended June 2006 is adequate for the rating. As of June 2006, adjusted leverage was also relatively moderate at 54%.	Jeanny Silva

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Alliant Energy Corp. (BBB+/Stable/A-2)

Alliant continues to shed its international assets, most recently with its decision to sell its interest in Alliant Energy New Zealand Ltd. Once this transaction is complete, Alliant's international activities will be confined to holdings in a handful of Chinese power plants and a small Mexican resort development, positioning the company to focus on its stable core U.S. utility operations, which in the past 12 months have enjoyed stronger earnings and cash flows relative to the same period last year due to electric rate increases, improved recoveries of fuel-	Jeanny Silva

related expenses, and more customers. At June 30, 2006, Alliant's nearly 20% adjusted FFO-to-debt (excluding pension adjustments) was adequate for the current level of business risk, and leverage is modest at about 46%.

Alliant Energy Resources Inc. (BBB+/Stable/A-2)	
See Alliant Energy Corp.	Jeanny Silva
Ameren Corp. (BBB/Watch Neg/A-2)	
Second-quarter results weakened due to higher fuel and transportation costs, decreased plant availability, costs associated with the breach of the Taum Sauk plant reservoir, and milder weather. These factors, coupled with reduced interchange sales, severe storm damage in July, the long-term absence of electric rate relief, and accelerating environmental expenditures will continue to pressure Ameren's financial profile. There is also significant uncertainty about large pending rate requests for the Illinois transmission and distribution subsidiaries and vertically integrated subsidiary Union Electric Co. Union Electric has asked the Missouri Public Service Commission to adopt a fuel-adjustment clause that would allow more timely recovery of fuel and purchased-power costs. Final orders are expected in November 2006 for fuel costs and in June 2007 for purchased power costs. Meanwhile, the Illinois auction has started, and final results are expected shortly.	Barbara Eiseman
AmerenEnergy Generating Co. (BBB/Watch Neg/--)	
See Ameren Corp.	Barbara Eiseman
American Electric Power Co. Inc. (BBB/Stable/A-2)	
AEP faces an almost constant cycle of regulatory proceedings in one or more of the 11 states in which it operates, as well as at the federal level. The Texas Public Utilities Commission's decision to cut stranded-cost recovery was a credit disappointment. The mostly coal-burning company will be spending a lot of money on environmental compliance, a massive undertaking that heightens operating risk and regulatory risk, and threatens AEP's generation cost advantage.	Todd Shipman
American States Water Co. (A-/Stable/--)	
Net income for the six months ended June 30, 2006 was $12.2 million, a 28% increase for the same period in 2005. Increased rates in California and Arizona and rising water consumption have increased earnings. Leverage moderated, and cash flow protection measures are adequate, with FFO coverage of interest at about 4.5x.	Michael Scholder
American Transmission Co. (A+/Stable/A-1)	
As American Transmission continues its extensive transmission building program, we expect that capital spending will not weaken the company's stable financial measures, which as of June 30, 2006, were very strong for the rating. The company's financial measures are expected to remain solid in part due to constructive FERC regulation and reliable operations.	Gerrit Jepsen
American Water Capital Corp. (A-/Watch Neg/--)	
The company's ultimate parent, German multiutility RWE AG (A+/Negative/A-1), is seeking regulatory approval for the planned spin-off and IPO of American Water, which should be finalized during the second half of 2007. The CreditWatch listing is not expected to be resolved until more details are known about the company's ownership structure, capital structure, and business plan following the IPO.	Plana Lee

Appalachian Power Co. (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
Aqua Pennsylvania Inc. (A+/Stable/--)	
Connecticut Water Service Inc.'s earnings should be lower in 2006 due to the sale of the company's Barnstable water operations for $10 million in May 2005. Connecticut Water Co. recently filed for a 30% rate increase, which is the first for the company in 15 years. A decision is expected by January 2007. Adjusted funds from operations to total debt of about 15%, and adjusted FFO interest coverage of 3.4x are weak for the current rating. The company may be pressured to maintain its modest financial risk profile without proper rate relief.	Plana Lee
Aquarion Co. (A/Watch Neg/--)	
Aquarion's pending sale to Macquarie Bank Ltd. awaits regulatory approval in Connecticut, New York, and New Hampshire. Macquarie's intended business strategy for Aquarion and a credit-conducive financing structure could support Aquarion's current rating level. The company's FFO interest coverage was 3.6x for the 12 months ended June 2006. Completion of the regulatory process is expected to occur during fourth-quarter 2006.	Plana Lee
Aquarion Water Co. of Connecticut (A/Watch Neg/--)	
See Aquarion Co.	Plana Lee
Aquila Inc. (B-/Watch Pos/B-3)	
We recently upgraded Aquila to 'B' from 'B-'. The company's ratings remain on CreditWatch with positive implications. Over the past year, Aquila has reduced business risk significantly, achieved material debt reduction, and lowered its ongoing working capital requirements. The *continued CreditWatch listing reflects Aquila's Kansas electric utility being sold and the* company's debt-reduction plan being completed. Adjusted debt-to-capital was about 67% (including pension adjustments) as of June 2006. Also, with the Elwood toll no longer contributing to a $40 million per year cash drain and with higher electric and gas rates in Missouri and Iowa in effect and lower overall interest expense, we expect currently negative adjusted FFO to improve by year end.	Jeanny Silva
Arizona Public Service Co. (BBB-/Stable/A-3)	
See Pinnacle West Capital Corp.	Anne Selting
Atlanta Gas Light Co. (A-/Negative/--)	
See AGL Resources Inc.	Michael Messer
Atlantic City Electric Co. (BBB/Stable/A-2)	
See PEPCO Holdings Inc.	Gerrit Jepsen
Atmos Energy Corp. (BBB/Stable/A-2)	
Financial performance for the first half of 2006 was weaker than expected, as warmer-than-normal weather resulted in lower volumes in its utility operations. However, increased operating income in its natural gas trading and marketing operations tempered the decline in operating income. Consequently, credit measures are somewhat weak for the ratings.	Andrew Watt

Avista Corp. (BB+/Stable/B-1)	
Avista's near-term credit quality is expected to be sustained by stable cash flows that, along with the proceeds from its continuous equity issuance, should be adequate to pay down reasonable debt levels and finance the capital program. Primary operating risks continue to be hydro flows, which have improved so far in 2006 and have slightly improve cash flow coverages. Avista Utilities is seeking electric and gas rate increases in Washington, Oregon, and Idaho, the largest of which is a nearly 9% electric rate request in Washington to become effective by February 2007.	Anne Selting
Baltimore Gas & Electric Co. (BBB+/Watch Pos/A-2)	
See Constellation Energy Group Inc.	Aneesh Prabhu
Baton Rouge Water Works Co. (The) (AA/Stable/--)	
To meet future supply needs in the high-growth Ascension Parrish area and to serve the increase in customers who moved from New Orleans after the 2005 hurricanes, capital expenditures are expected to remain elevated in 2006 and 2007. However, the one-time nature of these construction costs and the company's ability to cover most of them internally should negate any negative effects. Financial performance is expected to remain robust, led by the company's healthy free operating cash flow, its adjusted FFO to total debt ratio of greater than 30%, and its adjusted FFO interest coverage of greater than 5.5x.	Andrew Watt
Bay State Gas Co. (BBB/Stable/--)	
See NiSource Inc.	Barbara Eiseman
Black Hills Corp. (BBB-/Negative/--)	
The company continues to demonstrate weak financial ratios for the heightened level of business risk. For the 12 months ending June 2006, adjusted FFO to average debt (excluding pension adjustments) was 18%. We would expect lowering ratings if the company's business profile does not improve over the next six to 12 months. New and experienced management at the company's E&P division could help reverse the segment's track record of lower-than-expected performance.	Jeanny Silva
Black Hills Power Inc. (BBB-/Negative/--)	
See Black Hills Corp.	Jeanny Silva
Boston Edison Co. (A+/Stable/A-1)	
See NSTAR	Kenneth L. Farer
Boston Gas Co. (A/Watch Neg/--)	
See KeySpan Corp.	Kenneth L. Farer
California Water Service Co. (A+/Stable/--)	
Operating revenues have decreased slightly due to lower customer usage resulting from above-average rainfall through May 2006 and below-average temperatures into June 2006. Cash flow protection measures were adequate, with FFO coverage of interest at about 4x.	Michael Scholder

Calpine Construction Finance Co. L.P. (CCC-/Negative/--)	
On Dec. 21, 2005, Standard & Poor's Rating Services lowered its ratings on Calpine Corp. and some of its subsidiaries to 'D' after the company filed for bankruptcy protection. The ratings on Calpine Construction Finance Co. (CCFC) remains unchanged at 'CCC-', because this entity was excluded from the bankruptcy filing. However, there is a possibility that this entity could be filed in the future, although the likelihood has decreased in the months since the Calpine bankruptcy. A payment default by Calpine Energy Services (CES), under the terms of its gas sale and power purchase agreement with CCFC was an event of default under the terms of debt at CCFC. However, CCFC obtained a permanent waiver from the lenders. The default only pertained to operations during the period November 2005 through January 2006 and CES is currently making all payments due to CCFC.	Swami Venkataraman
Calpine Corp. (D/--/--)	
On Dec. 21, 2005, we lowered the ratings on Calpine and Calpine Generating Co. to 'D' after they filed for Chapter 11 bankruptcy protection.	Swami Venkataraman
Calpine Generating Co. LLC (D/--/--)	
We lowered its ratings on Calpine Corp. and Calpine Generating Co to 'D' after they filed for Chapter 11 bankruptcy protection.	Swami Venkataraman
Cambridge Electric Light Co. (A+/Stable/--)	
See NSTAR	Kenneth L. Farer
Carolina Power & Light Co d/b/a Progress Energy Carolinas Inc. (BBB/Stable/A-2)	
See Progress Energy Inc.	Jodi Hecht
Cascade Natural Gas Corp. (BBB+/Stable/--)	
On Feb. 15, 2006, the company filed with the Washington Utilities and Transportation Commission for its first base rate increase in 10 years. The company also requested approval of a "decoupling" mechanism to address the impact of retail sales volatility on fixed cost recovery. Exposure to gas cost volatility is mitigated by purchased gas cost adjustment mechanisms in Washington and Oregon, although regulatory lag issues can arise due to the build-up of deferred gas costs between adjustment dates. Cash flow coverage remains strong, while debt leverage has declined to favorable levels.	Leo Carrillo
CenterPoint Energy Houston Electric LLC (BBB/Stable/NR)	
During second-quarter 2006, Centerpoint reached settlement agreements regarding the tax treatment of the ZENs securities with the IRS and the rate case for CenterPoint Houston Electric. While these settlements reduce regulatory and tax uncertainty for the company and should allow management to focus on conducting day-to-day operations, the company is still working to resolve the issue of stranded-cost true-up for the Houston transmission and distribution operations. Centerpoint is making progress on its Southeast Supply Header pipeline project by signing FPL as an anchor shipper for 50% of capacity. The pipeline will connect the Perryville Hub to Gulfstream Natural Gas System.	Dimitri Nikas
CenterPoint Energy Inc. (BBB/Stable/--)	
During second-quarter 2006, Centerpoint reached settlement agreements regarding the tax treatment of the ZENs securities with the IRS and the rate case for CenterPoint Houston	Dimitri Nikas

Electric. While these settlements reduce regulatory and tax uncertainty for the company and should allow management to focus on conducting day-to-day operations, the company is still working on resolving the issue of stranded cost true-up for the Houston transmission and distribution operations. Centerpoint is making progress on its Southeast Supply Header pipeline project by signing FPL as an anchor shipper for 50% of capacity. The line will connect the Perryville Hub to Gulfstream Natural Gas System.

CenterPoint Energy Resources Corp. (BBB/Stable/--)

See CenterPoint Energy Inc. — Dimitri Nikas

Central Hudson Gas & Electric Corp. (A/Stable/--)

Parent CH Energy Inc.'s credit ratios (before adjusting for pension and other post-retirement obligations) are somewhat weak for the current rating, with FFO interest coverage of about 5x, FFO to debt of 17%, and debt to capital over 50%. Central Hudson's three-year rate agreement was approved in July 2006 and includes a $54 million increase in electric revenues and $14 million increase in gas revenues, although the authorized ROE of 9.6% is materially lower than the previous 10.3%. The increased revenues are required to cover increased operating costs, particularly pension and OPEBs, and infrastructure improvements. CH Energy has invested $25 million for various energy-related assets as part of its plan to build a portfolio with the proceeds from selling its generating facilities in 2001. — Kenneth L. Farer

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Central Illinois Light Co. (BBB-/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

Central Illinois Public Service Co. (BBB-/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

Central Maine Power Co. (BBB+/Negative/--)

See Energy East Corp. — Andrew Watt

Central Vermont Public Service Corp. (BB+/Stable/--)

Central Vermont's credit measures remain weak, with FFO interest coverage below 2x, FFO to debt below 10%, and debt to capital of over 70%. The company continues to implement its financial restoration plan and was granted a 4% rate increase for 2007. To generate investment-grade financial measures, substantive rate relief is required, given the company's material off-balance-sheet debt and somewhat nondiscretionary investments related to transmission system improvements. — Kenneth L. Farer

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CILCORP Inc. (BBB-/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

Cinergy Corp. (BBB/Positive/A-2)

See Duke Energy Corp. — Dimitri Nikas

Cleco Corp. (BBB/Negative/--)

Cleco recently issued $158 million in common stock to finance part of its 600 MW — Dimitri Nikas

Rodemacher Power Station. The equity issue (along with an interim rate plan approved in July 2006 that will extend through the construction of the plant in late 2009, and ability to recover 75% of the plant's financing costs in rates) should provide some buffer from financial risk. However, we view the project as having considerable financing and strategic risk, which pressures credit quality. The plant will address Cleco Power's shortfall in owned generation, which is currently filled through short-term power purchases and will represent some diversification away from natural gas as a fuel source. At the same time, the utility has been allowed to recover $161 million in 2005 hurricane costs over a lengthy 10 years, at the rate of $23.4 million annually.

Cleco Power LLC (BBB/Negative/--)	
See Cleco Corp.	Dimitri Nikas
Cleveland Electric Illuminating Co. (BBB/Stable/--)	
See FirstEnergy Corp.	Aneesh Prabhu
CMS Energy Corp. (BB/Stable/B-1)	
CMS Energy's significantly improved liquidity position, continued focus on low-risk core utility operations, and significant reduction of parent-level debt over the past few years resulted in an outlook change to stable from negative. CMS has maintained adequate liquidity throughout its travails. We project a leverage reduction to further support the rating profile.	Todd Shipman
Colonial Gas Co. (A/Watch Neg/--)	
See KeySpan Corp.	Kenneth L. Farer
Columbus Southern Power Co. (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
Commonwealth Edison Co. (BBB+/Watch Neg/A-2)	
See Exelon Corp.	Jeanny Silva
Commonwealth Electric Co. (A+/Stable/--)	
See NSTAR	Kenneth L. Farer
Connecticut Light & Power Co. (BBB/Stable/--)	
See Northeast Utilities	Andrew Watt
Connecticut Natural Gas Corp. (BBB+/Negative/--)	
See Energy East Corp.	Andrew Watt
Connecticut Water Co. (The) (A/Stable/--)	
See Connecticut Water Service Inc.	Plana Lee
Connecticut Water Service Inc. (A/Stable/--)	

Connecticut Water Service's earnings should be lower in 2006 due to the sale of its Barnstable water operations for $10 million in May 2005. Connecticut Water Co. recently filed for a 30% rate increase, which is the first rate increase for the company in 15 years. A decision is expected by January 2007. Adjusted FFO to total debt of about 15%, and adjusted FFO interest coverage of 3.4x are weak for the rating. The company may be pressured to maintain its modest financial risk profile without proper rate relief.	Plana Lee
Consolidated Edison Co. of New York Inc. (A/Negative/A-1)	
Con Edison announced a reduction in earnings guidance for 2006 after its 10-day power outage in Queens and smaller, sporadic interruptions in other parts of its New York City service territory. The new earnings target and reduced cash flow, associated with emergency response, permanent repairs, customer claims, and potential penalties, will further depress the company's already weak financial measures. At June 30, 2006, FFO to total debt was about 13%, FFO interest coverage was 3.1x, and debt to capital was 55%. The current ratings factor in the expectation that regulatory rate increases, such as subsidiary Consolidated Edison Co. of New York's rate increase of $220 million in 2007, will continue.	Kenneth L. Farer
Consolidated Edison Inc. (A/Negative/A-1)	
See Consolidated Edison Inc.	Kenneth L. Farer
Consolidated Natural Gas Co. (BBB/Stable/A-2)	
See Dominion Resources Inc.	Aneesh Prabhu
Constellation Energy Group Inc. (BBB+/Watch Pos/A-2)	
A new state law requires subsidiary Baltimore Gas & Electric Co. to defer recovery of power costs, but at the same time allows immediate relief through securitization. A troubling precedent of legislative intervention could still affect the utilty's credit quality if future supply cost increases are also controlled. Repricing of Constellations' power generation fleet is expected to increase cash flow on a consolidated basis. Conolidated financial measures are weak in 2006 after adjusting for debt-like obligations, but the use of proceeds from the proposed sale of 3,800 MW of gas-fired assets for debt reduction will benefit balance-sheet strength.	Aneesh Prabhu
Consumers Energy Co. (BB/Stable/B-1)	
See CMS Energy Corp.	Todd Shipman
Coral Energy Holding L.P. (A-/Stable/-)	
Parent Shell Oil's support for Coral is reflected in the company's revised recapitalization and injection of equity. Coral has a $750 million short-term revolver from a Shell affiliate, and Coral closed on a $1.95 billion five-year term facility in June 2006 that replaced the company's bridge facility with a Shell affiliate. Shell injected $250 million in equity into Coral in first-quarter 2006, an increase of about 55% over year-end 2005. This increase in financial capability reflects expectations of growth in North American markets.	Terry Pratt
Dayton Power & Light Co. (BB+/Positive/--)	
See DPL Inc.	Todd Shipman

Delmarva Power & Light Co. (BBB/Stable/A-2)	
See PEPCO Holdings Inc.	Gerrit Jepsen
Detroit Edison Co. (BBB/Stable/A-2)	
See DTE Energy Co.	Todd Shipman
Dominion Resources Inc. (BBB/Stable/A-2)	
Lower gas prices and mild weather have mitigated fuel-related expenses, which are unrecoverable above a frozen fuel factor through mid-2007. Exploration and production (E&P) volumes have rebounded with new production. Even so, Dominion E&P is feeling some service cost pressures. Recent changes in Virginia legislation obviate the need for E&P to act as a natural hedge for utility fuel costs. As a result, an ongoing asset review will likely determine future strategy. Liquidity concerns have receded with gas prices at a more sustainable level. Leverage is still high but will reduce some from the announced sale of four merchant generation plants. Coverage ratios and leverage will improve modestly by year-end from receipt of insurance payments for last year's hurricanes and the dividend reinvestment program. Free cash flow is expected to stay significantly negative in 2006 and hinders any upward ratings momentum.	Aneesh Prabhu
DPL Inc. (BB+/Positive/--)	
DPL recently hired a new CEO with utility industry experience, and expectations are that the business strategy will focus on the utility. The company has announced its intent to sell three gas peaking plants that have failed to generate positive returns; proceeds could be used to improve the financial profile by reducing debt. DPL's financial profile is slowly being restored, with FFO interest coverage for 2006 is expected to be 3.1x.	Todd Shipman
DTE Energy Co. (BBB/Stable/A-2)	
The implementation of a Michigan Public Service Commission-authorized transition charge has helped to slow sales losses from the customer choice program in first-quarter 2006. However, the commission is considering a rate decrease that could erode the company's financial profile below a level consistent with current ratings. The stable outlook on DTE is based in part in advancing a constructive regulatory agenda. Also, synthetic fuel operations were expected to generate about one third of total cash flow in 2006, but high oil prices could cut into that forecast.	Todd Shipman
Duke Capital LLC (BBB/Positive/A-2)	
See Duke Energy Corp.	Dimitri Nikas
Duke Energy Corp. (BBB/Positive/--)	
Duke's plans to separate the electric and natural gas operations are proceeding on schedule, with a start date of Jan. 1, 2007. We reviewed the company's proposal and revised the outlook on Duke Capital (in essence the core of the new gas company) to positive to reflect that entity's potential for a ratings upgrade of up to 2 notches. At the same time, the ratings on the remaining electric company were affirmed with a positive outlook to reflect the likelihood for a higher rating as well. Duke Energy has followed through with its plan to reduce and mitigate business risk at the regulated operations, most recently completing the sale of Cinergy's trading and marketing operations to Fortis NV of the Netherlands.	Dimitri Nikas
Duke Energy Trading and Marketing LLC (BBB-/Stable/--)	

See Duke Energy Corp.	Dimitri Nikas
Duke Energy Carolinas LLC (BBB/Positive/A-2)	
See Duke Energy Corp.	Dimitri Nikas
Duke Energy Kentucky Inc. (BBB/Positive/--)	
See Duke Energy Corp.	Dimitri Nikas
Duke Energy Ohio Inc. (BBB/Positive/A-2)	
See Duke Energy Corp.	Dimitri Nikas
Duquesne Light Co. (BBB/Watch Neg/--)	
See Duquesne Light Holdings Inc.	Gerrit Jepsen
Duquesne Light Holdings Inc. (BBB/Watch Neg/--)	
The company has multiple issues pending that can affect credit quality. The distribution and transmission rate proceedings could result in strengthened cash flow measures, particularly during the company's currently high capital spending phase. Moreover, rate increases will help maintain cash flow measures as other businesses such as synthetic fuel operations are phased out. Also, credit quality may be affected by the pending acquisition by Macquarie Infrastructure Partners and Diversified Utility and Energy Trusts, a unit of Macquarie Securities Inc., for $3.15 billion. Given the significant amount of debt financing being proposed, which would increas consolidated debt by one-third, financial measures will weaken after closing.	Gerrit Jepsen
Dynegy Holdings Inc. (B/Watch Dev/--)	
See Dynegy Inc.	Swami Venkataraman
Dynegy Inc. (B/Watch Dev/B-2)	
Ratings on Dynegy and its subsidiaries are on CreditWatch developing after the Sept. 15, 2005 announcement that it would acquire LS Power's assets. Since the purchase is financed mainly with Dynegy common stock, we expect to affirm all ratings on Dynegy and Dynegy Holdings if the transaction is consummated as currently expected. A key potential risk include additional operational or market risks to Dynegy that may arise from the future integration of LS Power assets.	Swami Venkataraman
E.ON U.S. LLC (BBB+/Stable/--)	
E.ON U.S.'s two utilities in Kentucky are good performers, with low costs, a reasonable regulatory environment, and high customer satisfaction ratings. Capital spending will be a priority for the next few years as environmental compliance upgrades and the new capacity requirements will burden the utilities with large cash needs. Parent E.ON AG continues to back up its support for LG&E Energy, which is important for ratings stability.	Todd Shipman
Edison International (BBB-/Stable/--)	
Ratings stability is expected in the near term following a recent rating downgrade in response to revised strategic policies that allow capital infusions to be made into unregulated subsidiaries if needed to support growth initiatives and if they are in the shareholders' best interest. The company exhibited steady to gradual improvement in fully adjusted FFO interest	David Bodek

coverage of about 2.9x and in FFO to total debt of about 15% as of June 30, 2006.

Edison Mission Energy (BB-/Positive/--)

The recent ratings upgrade reflects management's revised strategic policies that allow capital infusions to be made from Edison Mission Energy's ultimate parent, Edison International, into its unregulated subsidiaries if needed to support growth opportunities and if in the best interest of shareholders. — David Bodek

Edison Mission Marketing and Trading (BB-/Positive/--)

Edison Mission Marketing and Trading is rated on a consolidated basis with Edison Mission Energy. Trading and marketing activities are largely restricted to hedging activities for coal-fired generation. — David Bodek

El Paso Electric Co. (BBB/Stable/--)

Cash flow trends remain strong at El Paso Electric, but Palo Verde Unit 1, which represents about 200 MW of generation capacity for El Paso Electric, was shut down on Sept. 19, 2006 due to problems with its cooling system. Although expected to be short, the outage is likely to affect off-system sales, most of which occur in the shoulder months. FFO to interest coverage and FFO to debt ratio were a stong 5.7x and 26% respectively for the 12 months ended June 2006. Strong cash flow was driven by retail sales growth, a recovery of previously deferred fuel expense, and decreases in interest expense. — Chinelo Chidozie

Empire District Electric Co. (BBB-/Stable/A-3)

Empire acquired a gas utility for $100 million in July 2006, and steady financial performance will require a successful integration of the new operation. Empire's $30 million electric rate case pending before the Missouri Public Service Commission should be completed by year-end 2006. The case's outcome is important to Empire's creditworthiness given the lack of a permanent energy-cost recovery mechanism and heavy capital spending program. Financial measures have been mixed for the rating, and expected to remain so over the near term until there is more clarity on the pending rate case and energy cost recovery mechanism. — Gerrit Jepsen

Energen Corp. (BBB+/Stable/--)

With oil and gas prices at a cyclical high over the last two years, the company's exploration and production operations have helped boost consolidated cash flows. Energen is looking to increase its capital spending for drilling by $55 million to $75 million in 2007. FFO to total adjusted debt improved to 49.7% for the 12 months ending June 30, 2006. — Todd Shipman

Energy East Corp. (BBB+/Stable/A-2)

The New York State Public Service Commission's decision to approve a one-year rate plan that reduced New York State Electric & Gas's electric delivery rates by $36.2 million annually starting in January 2007 caused us to revise the outlook on Energy East and its subsidiaries to negative from stable on Aug. 25. The company had requested a $58 million increase in delivery rates. The decision will pressure credit measures in 2007, which were already expected to be weak for the ratings. — Andrew Watt

Enogex Inc. (BBB+/Stable/--)

See OGE Energy Corp. — Jeanny Silva

Entergy Arkansas Inc. (BBB/Negative/--)

See Entergy Corp.	Dimitri Nikas
Entergy Corp. (BBB/Negative/--)	
Entergy is pursuing recovery of hurricane-related costs in its service territories, incurred in 2005. While some progress has been made through the implementation of securitization bills in Texas and Louisiana, the timing of the recovery and amounts remain uncertain. Entergy estimates storm damage of $700 million in Louisiana and $390 million in Texas. The consolidated business risk profile reflects some pressure from ongoing regulatory challenges, as well as the company's increasing involvement in nonregulated generation, such as the recent purchase of the Palisades nuclear plant from Consumers Energy Co. Nevertheless, the company's financial profile remains robust with adequate credit protection measures for the 12 months ended June 30, 2006.	Dimitri Nikas
Entergy Gulf States Inc. (BBB/Negative/--)	
See Entergy Corp.	Dimitri Nikas
Entergy Louisiana LLC (BBB/Negative/--)	
See Entergy Corp.	Dimitri Nikas
Entergy Mississippi Inc. (BBB/Negative/--)	
See Entergy Corp.	Dimitri Nikas
Entergy New Orleans Inc. (D/--/--)	
See Entergy Corp.	Dimitri Nikas
Equitable Resources Inc. (A-/Watch Neg/A-2)	
The company is awaiting approval for its $970 million purchase of two Dominion Resources natural gas and midstream subsidiaries. This acquisition will greatly increase customer base and storage capacity, as well as rebalance the company's regulated and nonregulated business mix. The rating outcome is highly dependent on Equitable's ultimate financing plan, which will likely include a combination of equity and debt issuance and possibly hybrid issuance and/or asset sales. FFO interest coverage was 5.9x for the 12 months ending June 30, 2006.	Todd Shipman
Exelon Corp. (BBB+/Watch Neg/A-2)	
Ratings on Exelon and its subsidiaries (PECO Energy, Exelon Generation, and Commonwealth Edison) were affirmed and removed from CreditWatch negative on Sept. 15, 2006 after Exelon's decision to terminate its merger agreement with lower-rated Public Service Enterprise Group Inc. While fully adjusted and including pension adjustments cash flow protection at the consolidated level is moderate-to-weak at roughly 20% for the 12 months ending June 2006, we expect consolidated cash flows to improve. This is because weakened financial performance at ComEd resulting from the recent Illinois Commerce Commission's delivery service tariff rate order should be more than offset by the effect of additional (and higher margin) market sales at ExGen. ComEd's full-requirements contract with ExGen expires at the end of the year.	Jeanny Silva
Exelon Generation Co. LLC (BBB+/Watch Neg/A-2)	
See Exelon Corp.	Jeanny Silva
FirstEnergy Corp. (BBB/Stable/--)	

The company's rate certainity plan in Ohio will lower cash flow in the near term, but is viewed as credit neutral as it preserves the recovery of increased fuel costs after 2008. The company's operating performance has been satisfactory, but doubts remain on the sustainability of nuclear operations. Rate cases in Pennsylvania and the post-2008 market structure in Ohio are other risks. Climbing maintenance expenditures will cut into free cash flow in 2006. Financial metrics and liquidity have improved markedly as substantial debt was paid down in 2005. A share-repurchase program will bruise credit metrics, but they will still be in line with ratings.	Aneesh Prabhu
Florida Power & Light Co. (A/Watch Neg/A-1)	
See FPL Group Inc.	Jodi Hecht
Florida Power Corp d/b/a Progress Energy Florida Inc. (BBB/Stable/A-2)	
See Progress Energy Inc.	Jodi Hecht
Florida Progress Corp. (BBB/Stable/A-2)	
See Progress Energy Inc.	Jodi Hecht
FPL Group Capital Inc. (A/Watch Neg/A-1)	
See FPL Group Inc.	Jodi Hecht
FPL Group Inc. (A/Watch Neg/--)	
FPL Group's consolidated financial performance for the 12 months ended June 30, 2006 was below expectation, driven by the lingering cash flow impact of the 2004-2005 hurricanes and under-recovered fuel costs at the utility.The Creditwatch negative listing reflects the announced merger with Constellation Energy. The combined entity would likely have a higher business risk profile and weaker financial risk profile because it would have a significantly higher percentage of cash flow from higher-risk competitive businesses, with little change in the pro forma balance sheet.	Jodi Hecht
Georgia Power Co. (A/Stable/A-1)	
See Southern Co.	Terry Pratt
Golden State Water Co. (A-/Stable/--)	
See American States Water Co.	Michael Scholder
Great Plains Energy Inc. (BBB/Stable/--)	
Cash flow protection measures are currently adequate, with adjusted FFO to debt at about 25% (including pension adjustments) for the 12 months ending June 2006. That said, subsidiary Kansas City Power & Light's $1.3 billion five-year capital program might pressure the consolidated financial profile over the longer term--especially if regulatory support is not forthcoming. Stipulated agreements between KCPL and the Missouri and Kansas commissions have approved a multi-year plan that recognizes the need for future rate adjustments. In Missouri, KCPL is seeking a $56 million increase in electric revenues, and in Kansas, it is requesting $42 million. Rate case hearings are expected to start in mid-October.	Jeanny Silva
Green Mountain Power Corp. (BBB/Watch Pos/--)	
The ratings on Green Mountain remain on CreditWatch positive after Northern New England Energy Corp. (a Gaz Metro Inc. (A-/Negative/--) subsidiary) announced on June 22, 2006 it	Kenneth L. Farer

would acquire the company. Green Mountain's affiliation with a stronger entity could improve its overall credit profile, resulting in an upgrade. The company has negotiated a 9.6% rate increase (12% was requested) for 2007 to offset current high power and transmission costs. The Vermont Public Service Board must still approve Green Mountain's rate case and alternative regulatory plan. Over the intermediate term, Green Mountain will require additional rate relief to maintain financial measures appropriate for the current ratings, given the anticipated increases in power costs with the expiration of its power supply hedge.

Gulf Power Co. (A/Stable/--)

See Southern Co.	Terry Pratt

Hawaiian Electric Co. Inc. (BBB+/Negative/A-2)

See Hawaiian Electric Industries Inc.	Barbara Eiseman

Hawaiian Electric Industries Inc. (BBB/Negative/A-2)

Key financial metrics are subpar for the ratings, with adjusted FFO to debt at about 18% and total debt of 57%. Second-quarter electric sales were down 2.3% owing to cooler weather, conservation, and higher expenses, offset somewhat by higher earnings at the company's bank. A final rate order from the Hawaii Public Utilities Commission regarding subsidiary Hawaiian Electric's pending rate case is crucial to help lift financial measures to more appropriate levels and eliminating the rating's negative outlook. Also of some concern is Hawaii's Act 162, a new law that appears to confirm the PUC's ability to authorize the utility's fuel-adjustment clause. Although no parties to the case seem to oppose continuation of the clause, a material change to this mechanism would harm the company's financial profile and detract from its satisfactory business position.	Barbara Eiseman

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IDACORP Inc. (BBB+/Negative/A-2)

IDACORP Inc.'s financial ratios are expected to continue to improve to levels commensurate with its 'BBB+' rating mainly due to increased power sales revenues for its primary subsidary, Idaho Power, with the drought's end. Power sales revenues increased by 31% in first-half 2006 compared with 2005 results. Leverage moderated as total debt to EBITDA declined to 4.6x. Cash flow protection measures are adequate, with FFO coverage of interest at about 3.3x.	Michael Scholder

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Idaho Power Co. (BBB+/Negative/A-2)

Seee IDACORP Inc.	Michael Scholder

Illinois Power Co. (BBB-/Watch Neg/--)

See Ameren Corp.	Barbara Eiseman

Indiana Gas Co. Inc. (A-/Stable/--)

See Vectren Corp.	Gerrit Jepsen

Indiana Michigan Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc.	Todd Shipman

Indianapolis Power & Light Co. (BB+/Positive/--)

See IPALCO Enterprises Inc.	Barbara Eiseman
International Transmission Co. (BBB/Positive/--)	
See ITC Holdings Corp.	Gerrit Jepsen
Interstate Power & Light Co. (BBB+/Stable/A-2)	
See Alliant Energy Corp.	Jeanny Silva
IPALCO Enterprises Inc. (BB+/Positive/--)	
IPALCO's rating is capped at 'BBB-' due to its linkage to AES Corp. (BB-/Stable/--). IPALCO's outlook was revised in June 2006 to positive from stable as we expect certain key financial metrics to strengthen over the next couple of years due to somewhat lower-than-expected environmental-related capital outlays; supportive ratemaking treatment for such expenditures, including a return on the investment and recovery of depreciation and O&M expenses through an environmental tracking mechanism; reduced external funding needs; and tight cost controls. Currently strong internal funding of the company's construction program is expected to slip below 65% for 2006, when environmental-related spending peaks, and rebound to over 100% in 2007. Meanwhile, adjusted total debt to capital will hover around an exceptionally high 106% to 110%. The debt ratio reflects the use of pooling accounting associated with the original stock transaction versus the more typical purchase accounting, in which the assets are stepped up to fair market value.	Barbara Eiseman
ITC Holdings Corp. (BBB/Watch Neg/--)	
ITC's recent FERC approval to use a projected test period was positive for credit quality because it should boost operating cash flow and further support credit quality. The financing and integration of the company's acquisition of Michigan Electric Transmission Co. could be crucial to credit quality because the acquisition will be mostly debt-financed. Also, a pending METC rate proceeding could influence overall credit quality after the acquisition closes.	Gerrit Jepsen
Jersey Central Power & Light Co. (BBB/Stable/--)	
See FirstEnergy Corp.	Aneesh Prabhu
Kansas City Power & Light Co. (BBB/Stable/A-2)	
See Great Plains Energy Inc.	Jeanny Silva
Kansas Gas & Electric Co. (BB+/Positive/--)	
See Westar Energy Inc.	Barbara Eiseman
Kentucky Power Co. (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
Kentucky Utilities Co. (BBB+/Stable/A-2)	
See E.ON US	Todd Shipman

KeySpan Corp. (A/Watch Neg/A-1)	
The ratings on diversified energy company KeySpan Corp. and its subsidiaries remain on CreditWatch negative pending the company's sale to National Grid PLC (A/Watch Neg/A-1) for $7.3 billion plus the assumption of $4.5 billion of debt. We anticipate resolving the CreditWatch and lowering the ratings on KeySpan and its subsidiaries by one notch when the acquisition receives regulatory approval and becomes unconditional. Despite the acquisition, we expect additional improvement in KeySpan's cash flow measures and reduced leverage over the intermediate term.	Kenneth L. Farer
KeySpan Energy Delivery Long Island (A+/Watch Neg/--)	
See KeySpan Corp.	Kenneth L. Farer
KeySpan Energy Delivery New York (A+/Watch Neg/--)	
See KeySpan Corp.	Kenneth L. Farer
KeySpan Generation LLC (A/Watch Neg/--)	
See KeySpan Corp.	Kenneth L. Farer
Kinder Morgan Inc. (BBB/Watch Neg/A-2)	
The implementation of a Michigan Public Service Commission-authorized transition charge has helped to slow sales losses from the customer choice program in first-quarter 2006. However, the commission is considering a rate decrease that could erode the company's financial profile below a level consistent with current ratings. The stable outlook on DTE Energy Co. is based in part in advancing a constructive regulatory agenda. Also, synthetic fuel operations were expected to generate about one-third of total cash flow in 2006, but high oil prices could cut into that forecast.	Todd Shipman
Laclede Gas Co. (A/Stable/A-1)	
See Laclede Group Inc.	Barbara Eiseman
Laclede Group Inc. (The) (A/Stable/--)	
Certain key financial measures are somewhat weak for the ratings, with FFO to debt at about 21% and total debt to capital at about 54%. However, full realization of a modest net rate increase of $4 million, weather-mitigation rate design, cost-containment and operational efficiencies, a gas supply incentive plan, the issuance of new shares of stock under LG's dividend reinvestment plan, and expectations for increased profits from the company's unregulated ventures should modestly strengthen the company's financial condition. The company's recent purchase of Reliant Services LLC's Indiana assets was relatively small and funded with cash on hand. Nonetheless, should SM&P Utility Resources Inc. continue to expand its geographic footprint into new markets, consolidated business risk will increase, requiring a stronger consolidated financial profile to maintain the current rating level.	Barbara Eiseman
Louisville Gas & Electric Co. (BBB+/Stable/A-2)	
See E.ON US	Todd Shipman

Madison Gas & Electric Co. (AA-/Stable/A-1+)

The company's financial measures are expected to weaken during a heavy capital spending program and are expected to stabilize at a level in line with the rating in the next several years. We will continue to monitor the construction program and any effects on financial measures.	Gerrit Jepsen

Massachusetts Electric Co. (A/Watch Neg/A-1)

See National Grid USA	Kenneth L. Farer

Metropolitan Edison Co. (BBB/Stable/--)

See FirstEnergy Corp.	Aneesh Prabhu

Michigan Consolidated Gas Co. (BBB/Stable/A-2)

See DTE Energy Co.	Todd Shipman

MidAmerican Energy Co. (A-/Stable/A-1)

We expect continued stable performance from MidAmerican, which had cash flow coverage of interest and debt of 5.3x and 29.8% for the 12 months ended June 30, 2006. The Council Bluffs coal plant should be completed in 2007. MidAmerican has completed 360 MW of wind generation and received approval for another 545 MW in April. The company's rate settlement agreement extends through Dec. 31, 2011. The rate settlement does not incorporate a fuel-adjustment clause, which may be problematic given increasing fuel costs, but this is mitigated by the ability to request a rate increase should the actual earned Iowa jurisdictional ROE falls below 10%.	Swami Venkataraman

MidAmerican Energy Holdings Co. (A-/Stable/--)

While MEHC's credit metrics are improving, ratios are clearly weak for the 'A-' rating, which benefits from Berkshire Hathaway's support. For the 12 months ended June 30, 2006, FFO/interest and debt stood at 2.7x and 10.5%, respectively. Debt to total capital had shown a substantial improvement from 77.4% as of Dec. 31, 2005 to 70.9% as of March 31, 2006, reflecting the equity infusion for the acquisition of PacifiCorp. It further improved marginally to 70.2% as of June 30, 2006. MEHC continues to look for investment opportunities, which would likely be funded in large part by equity from Berkshire Hathaway.	Swami Venkataraman

Middlesex Water Co. (A-/Stable/--)

Middlesex Water Co. has continued heavy capital-spending needs at subsidiary Tidewater Utilities Inc. due to high customer growth. In addition, regulatory treatment for new wastewater operations at Tidewater Environmental Services Inc., which is also expected to be capital-intensive, remains uncertain given recently passed legislation in Delaware concerning regulating wastewater facilities. However, planned equity issuance by the end of 2006 is expected to support the company's credit measures.	Plana Lee

Midwest Independent System Operator Inc. (MISO) (A+/Stable/--)

Louisville Gas & Electric Co.'s withdrawal and Kentucky Utilities Co.'s expected withdrawal from MISO will not affect its rating because the utilities must pay a lump sum exit fee that MISO can use over time to cover the financial obligations related to the utilities' participation in MISO, including interest and principal payments on debt. Nevertheless, a large exodus of	Gerrit Jepsen

higher-load members could introduce financial risk because remaining MISO members would be required to pay for a greater share of costs for operations, financing, and capital expenditures.	
Mirant Americas Generating LLC (B+/Stable/--)	
See Mirant Corp.	Terry Pratt
Mirant Corp. (B+/Stable/--)	
Management recently reaffirmed its interest in a stock buy-back program, funded from cash and expected proceeds from the Asian and Caribbean asset sales, which curently provide about one-half of EBITDA. But Mirant has also stated its goal of maintaining its credit rating by using proceeds to establish a capitalization plan that has sufficient liquidity to meet capital expenditures, supply working capital needs, and support trading operations. Mirant also announced the sale of 3,504 MW of U.S. gas-fired capacity.	Terry Pratt
Mirant Mid-Atlantic LLC (BB/Stable/--)	
See Mirant Corp.	Terry Pratt
Mirant North America LLC (B+/Stable/--)	
See Mirant Corp.	Terry Pratt
Mississippi Power Co. (A/Stable/A-1)	
See Southern Co.	Terry Pratt
Monongahela Power Co. (BB+/Positive/--)	
See Allegheny Energy Inc.	Aneesh Prabhu
MXEnergy Holdings Inc. (B/Stable/--)	
MXEnergy acquired ratings in connection with the $200 million unsecured debt issued to finance the SESCo acquisition. Management's immediate focus will be on integrating SESCo and implementing formal internal controls for accounting and risk management. Continuing to acquire customers at competitive rates is key. MXEnergy's fiscal year ends June 30, 2006, and financial statements are not yet available. The company is not required to file with the SEC. Consolidated FFO coverage of interest is expected to be about 1.8x and 11.5%, respectively, in 2007.	Swami Venkataraman
Narragansett Electric Co. (A/Watch Neg/A-1)	
See National Grid USA	Kenneth L. Farer
National Fuel Gas Co. (BBB+/Stable/A-2)	
National Fuel has submitted a rate case agreement with the Pennsylvania Public Utility Commission to increase annual revenues by $25.9 million. The in-service date for the company's planned expansion of its Empire State Pipeline has been pushed back a year to November 2008. Currently, 150 MDth of the planned 250 MDth/d capacity has been subscribed to. Financially, the company's credit metrics have improved, yet they are still subject to volatile natural gas prices and potential ceiling test writedowns. FFO interest coverage was 6.1x for the 12 months ended June 30, 2006.	Todd Shipman

National Grid USA (A/Watch Neg/A-1)

The ratings on electricity and gas provider National Grid USA and all its subsidiaries remain on CreditWatch with negative implications, following the pending acquisition of KeySpan Corp. by parent National Grid PLC (A/Watch Neg/A-1) for $7.3 billion plus the assumption of $4.5 billion of debt. We anticipate resolving the CreditWatch listing and lowering the ratings on National Grid USA and its subsidiaries by one notch when the acquisition receives regulatory approval and becomes unconditional. Over the intermediate term, the acquisition of KeySpan and significant capital programs will likely weaken consolidated credit ratios, although National Grid USA should maintain stronger credit measures than the consolidated company.	Kenneth L. Farer

Nevada Power Co. (BB-/Stable/--)

See Sierra Pacific Resources	Swami Venkataraman

New England Power Co. (A/Watch Neg/A-1)

See National Grid USA	Kenneth L. Farer

New Jersey Natural Gas Co. (A+/Negative/A-1)

At June 30, 2006, credit measures were appropriate for the current rating, with consolidated debt to capital of about 47%, adjusted funds from operations interest coverage of about 5x, and adjusted FFO to average total debt of 20%. Ratings stability could be achieved through a number of factors, including a greater focus on regulated investments, continued strong credit metrics, and prudently financed growth projects. Conversely, a downgrade could result from a continued increase in the proportion of unregulated activities at parent NJR or liquidity demands from increased commodity prices.	Kenneth L. Farer

New York State Electric & Gas Corp. (BBB+/Stable/A-2)

See Energy East Corp.	Andrew Watt

New York Water Service Corp. (BB/Watch Pos/--)

The ratings on New York Water Service Corp. are on CreditWatch with positive implications due to the May announcement that regulated water utility Aqua America Inc. has reached an agreement with Utilities & Industries Management Corp. to acquire the utility.	Plana Lee

Niagara Mohawk Power Corp. (A/Watch Neg/--)

See National Grid USA	Kenneth L. Farer

Nicor Gas Co. (AA/Negative/A-1+)

See Nicor Inc.	Barbara Eiseman

Nicor Inc. (AA/Negative/A-1+)

Financial metrics continued to slip in the second quarter, with FFO interest coverage and FFO to total debt hovering around 3.3x and 18%, respectively. In June 2006, Nicor reached a tentative agreement with SEC staff for a manageable fine of $10 million of an anticipated civil action relating to an investigation of subsidiary Nicor Gas' accounting for natural gas costs	Barbara Eiseman

pursuant to its performance-based rate (PBR) plan from 2000 through 2002. Of greater concern is the Illinois Commerce Commission's review of the PBR in which various parties have filed for adjustments of $108 million to $190 million. In addition, gas supply costs are open to the risk of hindsight prudence reviews by regulators, with 1999-2005 currently under review.

NiSource Inc. (BBB/Stable/--)

Certain key financial metrics remain subpar for the ratings with adjusted FFO to total debt at 13% and total debt hovering around 59%. Although some modest decline in bondholder protection was expected due to pipeline recontracting at lower rates as well as the requirement to increase sharing of offsystem sales and capacity release proceeds in Ohio, recent lower usage and customer attritionin the natural gas distribution segment may further pressure the company's financial profile. As of the second quarter, the company reported it has concluded the analytic phase of a comprehensive financial and strategic review, and is continuing the process. NiSource expects to report on its conclusions and direction by the end of the year.	Barbara Eiseman

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North Shore Gas Co. (A-/Negative/A-2)

See Peoples Energy Corp.	Jeanny Silva

Northeast Generation Co. (B+/Watch Pos/--)

See Northeast Utilities	Andrew Watt

Northeast Utilities (BBB/Stable/--)

NU's recently announced sale of its generation assets, including Northeast Generation Co., is one further step in divesting its nonregulated businesses. Over time this is expected to improve its business profile. The company expects total net proceeds of between $500 million and $550 million from the generation sales after accounting for taxes, sale expenses, and nonrecourse debt. NU expects to use these funds mainly for regulated business construction costs, as well as system debt reduction. We will continue to incorporate the exposure of these competitive businesses into its overall credit quality assessment until such time as the exit is completed, which we anticipate will be year-end 2006.	Andrew Watt

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Northern Indiana Public Service Co. (BBB/Stable/--)

See NiSource Inc.	Barbara Eiseman

Northern Natural Gas Co. (A/Stable/--)

Northern Natural Gas was upgraded to 'A' from 'A-' on March 16, 2006. Structural ring-fencing provisions allow for a ratings separation from parent MidAmerican Holdings Co. Recontracting risk has been significantly reduced with long-term extensions with Minnesota Gas and Northern States Power - Minnesota. A rate settlement reached in 2005 will provide for rate stability until November 2007 .	Swami Venkataraman

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Northern States Power Co. (BBB/Stable/A-2)

See Xcel Energy Inc.	David Bodek

Northern States Power Wisconsin (BBB+/Stable/--)

See Xcel Energy Inc.	David Bodek

Northwest Natural Gas Co. (AA-/Stable/A-1)

The ratings on Northwest Natural were raised in February 2006 due to strong sustained financial performance and an excellent business risk profile. FFO to interest coverage and FFO to total debt for the 12 months ended June 30, 2006, stood at 4.1x and 19.1%, respectively. The company has a conservative hedging policy, but has increased cash flow exposure by reducing targeted hedge levels below those of prior winter seasons. Additional pipeline investments are being considered. TransCanada's Gas Transmission Northwest system and Northwest Natural are holding an open season for the new 220-mile Palomar Gas Transmission project. The system could be configured to serve liquefied natural gas facilities that have been proposed for the Columbia River.	Michael Scholder
NorthWestern Corp. (BB+/Watch Neg/--)	
NorthWestern Corp.'s CreditWatch listing reflects the pending acquisition of the utility by Babcock & Brown Infrastructure Ltd. (BBI) for $2.2 billion, with $505 million of new debt at an intermediate holding company, a mix of funds from BBI and BBI's assumption of NorthWestern's existing debt. NorthWestern's credit measures, which now adequately support the 'BB+' rating, would weaken after the transaction closes in mid-2007 due to the incremental debt, which could put downward rating pressure on the company. Also, we will monitor the rate review filing that will be filed soon for any cash flow implications to the company.	Gerrit Jepsen
NRG Energy Inc. (B+/Stable/B-2)	
The recent, unexpected announcement of a sharp increase in near-term needs for capital expenditures to meet emissions compliance regulations leaves open the question of the amount of debt financing that will be needed to support the expanded capital program, as well as questions regarding management's oversight of such exposures.	David Bodek
NSTAR (A+/Stable/A-1)	
NSTAR's pursuit of transmission and distribution activities and maintenance of a strong financial profile support the current ratings. Financial performance in 2006 has been below historical levels, in part due to the deferral of transition costs. Over the intermediate term, we expect FFO interest coverage to average more than 5x with FFO to debt to of about 25% (about 3.5x and 20%, respectively, at June 30, 2006). Debt leverage is currently 65%, but should gradually decline because of higher retained earnings and minimal debt maturities.	Kenneth L. Farer
NSTAR Gas Co. (A+/Stable/--)	
See NSTAR	Kenneth L. Farer
OGE Energy Corp. (BBB+/Stable/A-2)	
FFO were up nearly 10% during the 12 months ending June 2006 (as compared with the same period last year) due to higher rates and favorable weather at OG&E and higher gross margins on gathering and processing activities at Enogex. Adjusted credit metrics are adequate for the rating. New plans for increased capital expenditures could pressure ratings over the intermediate term. In July 2006, the company announced plans for OG&E to build a new 950 MW coal unit at its existing Sooner plant for about $1.8 billion. OG&E would own 42% of the plant.	Jeanny Silva
Ohio Edison Co. (BBB/Stable/--)	
See FirstEnergy Corp.	Aneesh Prabhu
Ohio Power Co. (BBB/Stable/--)	

See American Electric Power Co. Inc.	Todd Shipman
Ohio Valley Electric Corp. (BBB-/Stable/--)	
OVEC's owner-customers take virtually all of the generation the company produces. Coal inventories are adequate, but upgrade work at the Kyger Creek plant's coal-handling facilities resulted in availability reductions, and inventory recovery has been slowed due to competing barge traffic. Leverage is high, and cash flow protection measures are very thin, with FFO coverage of interest at about 1.2x.	Michael Scholder
Oklahoma Gas & Electric Co. (BBB+/Stable/A-2)	
See OGE Energy Corp.	Jeanny Silva
Orange and Rockland Utilities Inc. (A/Negative/A-1)	
See Consolidated Edison Inc.	Kenneth L. Farer
Orion Power Holdings Inc. (B/Negative/--)	
See Reliant Energy Inc.	Dimitri Nikas
Otter Tail Corp. (BBB+/Stable/--)	
Credit metrics are adequate for the current rating category, with adjusted FFO to debt (including pension obligations) for the 12 months ending June 2006 at 26% and adjusted debt to capital at about 52%. Construction of Big Stone II, estimated to begin in summer 2007, could pressure the company's intermediate financial profile. Otter Tail has a relatively large $381 million capital plan for electric construction in the intermediate term. A large portion of this is for Big Stone II, a 600 MW coal-fired generation unit that the company will develop and operate for its own use and on behalf of six other regional participant-owners.	Jeanny Silva
Pacific Gas & Electric Co. (BBB/Stable/--)	
Long-term electricity- and fuel-procurement activities are ongoing and will define the utility's operational and financial profile. The California Public Utilities Commission remains committed to providing relief in response to material changes in utility costs, which contributes to rating stability. The company exhibited gradual improvements in cash flow coverage measures at June 30, 2006, with fully adjusted FFO to interest coverage of 3.4x and FFO to total debt of about 18%.	David Bodek
PacifiCorp (A-/Stable/A-2)	
For the 12 months ended June 30, 2006, PacifiCorp's cash flow coverage of interest and debt stood at 3.3x and 16.8%, respectively. Recent Oregon and Utah settlements, while significantly below the original request, are consistent with expectations in our forecast, although Washington continues to be a challenge on cost-allocation issues. The final criteria for the implementation of SB408 should have limited impact on PacifiCorp. We expect substantial equity contributions from MEHC to finance PacifiCorp's $6.4 billion five-year capex program. The company received $73.6 million in second-quarter 2006.	Swami Venkataraman
PanEnergy Corp. (BBB/Positive/--)	
See Duke Energy Corp.	Dimitri Nikas
PECO Energy Co. (BBB+/Watch Neg/A-2)	

See Exelon Corp.	Jeanny Silva
Pennsylvania Electric Co. (BBB/Stable/--)	
See FirstEnergy Corp.	Aneesh Prabhu
Pennsylvania Power Co. (BBB/Stable/--)	
See FirstEnergy Corp.	Aneesh Prabhu
Peoples Energy Corp. (A-/Negative/A-2)	
Peoples announced merger plans with WPS Resources Corp. (A/Watch Neg/A-1). Interim financials are negatively affected by the settlement charge related to gas purchase prudence proceedings that were settled in March 2006 and the write-off of $207 million of bad debt expense.	Jeanny Silva
Peoples Gas Light & Coke Co. (The) (A-/Negative/A-2)	
See Peoples Energy Corp.	Jeanny Silva
PEPCO Holdings Inc. (BBB/Stable/A-2)	
The company's performance through 2007 should remain steady. The outcome of upcoming distribution rate filings in Maryland will be important since supportive regulation would strengthen creditworthiness and financial performance. Creditworthiness would be bolstered by rate relief that would ease strained cash flow measures as a result particularly of power cost deferrals of at least one year from mid-2006.	Gerrit Jepsen
Piedmont Natural Gas Co. Inc. (A/Stable/--)	
Piedmont is waiting the PSCSC's approval of its proposed rate change, which, if okayed, will result in a $6.5 million revenue increase. The company also has a 50% interest in Hardy Storage Co., which intends to build, own, and operate an underground interstate gas storage facility in West Virginia. Piedmont's credit metrics were down slightly over the past 12 months, with FFO interest coverage at 4.2x as of June 30, 2006.	Todd Shipman
Pinnacle West Capital Corp. (BBB-/Stable/A-3)	
Principal subsidiary Arizona Public Service Co. is requesting a 21% increase in retail electric rates, but the commission staff recommended only 9.8%, stating that it may be difficult to improve the company's weakened financial profile. Base rates for fuel and purchased power are benched to 2003 costs, and the company suffers from a relatively weak power supply adjuster that has led to about $175 million as of June 30, 2006, and regulatory lag. Hearings on the rate case begin in October 2006.	Anne Selting
Pivotal Utility Holdings (A-/Negative/--)	
See AGL Resources Inc.	Michael Messer
PNM Resources Inc. (BBB/Negative/A-3)	
Credit ratios remain weak at PNM Resources, but we expect near-term improvement as the company has committed to paying down debt. When this is achieved, the credit quality of the consolidated company will depend on PNM's ability to manage the retail business in New	Chinelo Chidozie

Mexico, the competitive retail business in Texas, and the wholesale business in the Western electric markets.

Portland General Electric Co. (BBB+/Negative/A-2)

Higher operating costs and several forced outages at the 585 MW Boardman coal plant have resulted in weakened financial measures, with FFO/ average total debt falling to a weak 18% for the 12 months ended June 30, 2006, versus 22% for the similar period ending Dec. 31, 2005. The plant returned to service in July 2006, after experiencing its third forced outage since October 2005, resulting in about $52 million in replacement power costs that the company will seek to recover in a separate rate filing. In addition to the general rate case filed with state regulators in March 2006, the company has already filed for deferral of those replacement power costs incurred through Feb. 5, 2006, when Boardman returned to service after the first plant outage. Other factors supporting the negative outlook include weak projected financial metrics, litigation surrounding PGE's right to earn a return on its Trojan investment, and the City of Portland's attempts to investigate PGE's taxes and trading practices.	Leo Carrillo

Potomac Capital Investment Corp. (BBB-/Stable/NR)

See PEPCO Holdings Inc.	Gerrit Jepsen

Potomac Edison Co. (BB+/Positive/--)

See Allegheny Energy Inc.	Aneesh Prabhu

Potomac Electric Power Co. (BBB/Stable/A-2)

See PEPCO Holdings Inc.	Gerrit Jepsen

PPL Corp. (BBB/Stable/--)

In 2006, PPL Corp.'s merchant assets benefit from higher energy prices in the PJM region and the Pacific Northwest. Margins also benefit from a price escalator in its generation rate cap with PPL Electric Utilities. Plant uprates and higher volumes on non-POLR volumes will aid cash flow through 2006. Still, the company needs a sustained period of current price levels to fund projected capital spending needs on pollution-control equipment. To ensure sufficient cash flow, the company has hedged output and coal requirements for 2006, and recently signed a long-term coal contract with Consol Energy through 2018. Liquidity remains adequate with about $2 billion availability under PPL Energy's credit lines, but PPL's debt leverage remains high at about 56%.	Aneesh Prabhu

PPL Electric Utilities Corp. (A-/Stable/A-2)

The utility's financial profile continues to benefit from a $194 million rate increase in 2004, which also provided for recovery of all PJM-related transmission costs. Mild weather in the first half of 2006 affected earnings modestly. A lower court ruling revoked damages from a 2003 storm, but is being appealed. Operations continue to be in the top decile.	Aneesh Prabhu

PPL Energy Supply LLC (BBB/Stable/--)

See PPL Corp.	Aneesh Prabhu

Progress Energy Inc. (BBB/Positive/A-2)

Financial performance for the 12 months ending June 30, 2006 improved slightly as the fuel surcharge for PEF and PEC continue. Adjusted FFO to average debt improved to 15% compared with 14% in the prior year. The short-term focus remains on the execution of the debt reduction plan as the company exits higher-risk businesses.	Jodi Hecht
PSEG Energy Holdings LLC (BB-/Negative/B-2)	
See Public Service Enterprise Group Inc.	Aneesh Prabhu
PSEG Power LLC (BBB/Negative/--)	
See Public Service Enterprise Group Inc.	Aneesh Prabhu
Duke Energy Indiana Inc. (BBB/Positive/A-2)	
See Duke Energy Corp.	Dimitri Nikas
Public Service Co. of Colorado (BBB/Stable/A-2)	
See Public Service Enterprise Group Inc.	Aneesh Prabhu
Public Service Co. of New Hampshire (BBB/Stable/--)	
See Northeast Utilities	Andrew Watt
Public Service Co. of New Mexico (BBB/Negative/A-3)	
See PNM Resources Inc.	Chinelo Chidozie
Public Service Co. of North Carolina Inc. (A-/Stable/A-2)	
See SCANA Corp.	Dimitri Nikas
Public Service Co. of Oklahoma (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
Public Service Electric & Gas Co. (BBB/Negative/A-3)	
See Public Service Enterprise Group Inc.	Aneesh Prabhu
Public Service Enterprise Group Inc. (BBB/Negative/A-3)	
Meaningful debt reduction is contemplated, with the cash distributions from PSEG Energy Holdings after the termination of merger proceedings with Exelon. Cash flow over the next six months will benefit from revenue enhancements associated with the New Jersey Board of Public Utilities' most recent wholesale electricity auction and from operational improvements. Both electric and gas rate cases were delayed due to merger proceedings, but are expected to be filed soon.	Aneesh Prabhu
Puget Energy Inc. (BBB-/Stable/--)	
Regulatory support will be a decisive factor in driving possible rating improvement as the	Leo Carrillo

company implements a $1.4 billion two-year capital program for 2006 and 2007 that includes completion in 2006 of the 220 MW Wild Horse wind project. Puget's current rate case filing requests additional rate relief, a higher allowed ROE and equity ratio, approval of a major power-purchase contract and several major capital additions, and several major improvements to PSE's rate structure, including modification to its power cost adjustment mechanism and the addition of a gas "decoupling" mechanism and depreciation tracker. Balance-sheet measures are adequate, but cash flow measures are weak, with FFO/interest coverage of just 2.4x for the 12 months ended June 30, 2006.

Puget Sound Energy Inc. (BBB-/Stable/A-3)

See Puget Energy Inc.	Leo Carrillo

Questar Corp. (--/--/A-2)

The FERC recently approved Questar-owned pipeline expansion in southwest Wyoming. A binding precedent agreement has already been made for up to 300,000 decatherms per day (Dth/d) of the 500,000 Dth/d expansion. Operating performance of the company's exploration and production unit continues to be strong. Cash flow certainty is high for the remainder of 2006, as the company has hedged about 70% of its anticipated natural gas production with fixed-price swaps. Credit measures are solid for the rating, with FFO interest coverage at 11.4x for the 12 months ending June 30, 2006.	Todd Shipman

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Questar Gas Co. (A-/Stable/--)

See Questar Corp.	Todd Shipman

Questar Market Resources Inc. (BBB+/Stable/--)

See Questar Corp.	Todd Shipman

Questar Pipeline Co. (A-/Stable/--)

See Questar Corp.	Todd Shipman

Reliant Energy Inc. (B/Negative/--)

Reliant has entered into a credit sleeve arrangement with Merrill Lynch for the retail electric operations, under which Merrill Lynch will guarantee Reliant's energy purchases for a fee. The transaction is positive for credit quality because it will release considerable collateral currently held by counterparties. However, the transaction is contingent on Reliant's ability to obtain sufficient consent from existing bondholders. Reliant's credit-protection measures remain weak for the 12 months ended June 30, 2006, but could begin to benefit once the price-to-beat mechanism goes away beginning Jan. 1, 2007.	Dimitri Nikas

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Reliant Energy Mid-Atlantic Power Holdings LLC (B/Negative/--)

See Reliant Energy Inc.	Dimitri Nikas

Rochester Gas & Electric Corp. (BBB+/Stable/A-2)

See Energy East Corp.	Andrew Watt

Rockland Electric Co. (A/Negative/A-1)

See Consolidated Edison Inc.	Kenneth L. Farer
San Diego Gas & Electric Co. (A/Stable/A-1)	
We expect continued stable financial performance from SDG&E and a reduction in dividends to parent Sempra Energy as SDG&E is entering a period of significant rate base growth in generation and transmission and is also in the process of contracting for substantial renewable assets. Cash flow coverages at the utility weakened in the second quarter owing to deferred tax reversals. Cash flow coverage of interest and debt dropped to 3.2x and 14.7%, respectively but are expected to return to historic levels. For 2005, the ratios were 4.9x and 26.7%, respectively, justifying SDG&E's higher rating. Key CPUC decisions expected in 2006 include the participation in the SONGS steam generator replacement project and the advanced metering initiative.	Swami Venkataraman
Savannah Electric & Power Co. (A/Stable/--)	
See Southern Co.	Terry Pratt
SCANA Corp. (A-/Stable/--)	
SCANA is continuing with its efforts to moderate its financial risk profile through ongoing maturity redemptions. The business risk profile remains strong, reflecting that SCE&G continues to contribute more than 90% of net income and 80% of cash flow, supported by a constructive regulatory eniivironment and attractive service territory. Credit protection measures have weakened when compared with the 12 months ended June 30, 2005, but remain adequate for the rating.	Dimitri Nikas
Scottish Power Finance U.S. (A-/Stable/--)	
SPFUS serves as the guarantor for unrated operations of PPM Energy and PPM Energy Canada Ltd., which constitute substantially all of Scottish Power's operations in the U.S. SPFUS's ratings are based wholly on the consolidated credit strength of Scottish Power UK PLC, which has pledged to support SPFUS through an unconditional guarantee and support agreement. SPFUS's guarantees are pari passu with the other senior unsecured obligations of Scottish Power and are rated 'BBB+'. Certain obligations of PHI, the guarantor of PPM, remain with PHI, which is currently unrated.	Swami Venkataraman
SEMCO Energy Inc. (BB-/Stable/--)	
Recent refinancings are expected to help reduce the company's interest expense and should improve some coverage metrics. However, SEMCO will remain challenged to reduce its high level of debt. A pending rate decision with the Michigan Public Service Commission could positively affect cash flow in the future if rate design changes are implemented.	Todd Shipman
Sempra Energy (BBB+/Stable/A-2)	
Consistent and predictable financial performance is expected at the utilities and Sempra Generation. Significant upcoming capital expenditures at the utilities, LNG projects, the Rockies Express pipeline, and perhaps additional nonregulated assets could limit the amount of debt that can be paid down. Under conservative assumptions for Sempra Commodities, ratios are expected to be weak for the rating in 2006 and 2007, with FFO coverage of interest and debt somewhat lower than 4x and 23%, respectively. This is because Sempra invested substantial sums in its LNG and pipelines businesses without any cash flows. For the 12 months ended June 30, 2006, these ratios stood at 4.1x and 22.8%, respectively. Ratios will improve significantly from 2008 onward, even under conservative assumptions for SC.	Swami Venkataraman

Sierra Pacific Power Co. (BB-/Stable/--)	
See Sierra Pacific Resources	Swami Venkataraman
Sierra Pacific Resources (BB-/Stable/B-2)	
On Sept. 22, 2006, Standard & Poor's raised its corporate credit rating on Sierra Pacific Resources and its subsidiaries to 'BB-' from 'B+', reflecting the cumulative effect of improved business and financial risk profiles. The business risk score improved to '5' from '6' owing to a substantially improved and sustained regulatory relationship and asset acquisitions that have significantly reduced the utilities' short capacity and energy position. Prospects for future upgrades will be challenged by the substantial capital expenditures at the utilities that will limit the ability to pay down debt. For the 12 months ended June 30, 2006, FFO coverage of interest and debt stood at 2.5x and 10.2%, respectively, adequate for the rating. We forecast similar ratios in the next few years, but expect them to weaken during the construction of the Ely Center project.	Swami Venkataraman
South Carolina Electric & Gas Co. (A-/Stable/A-2)	
See SCANA Corp.	Dimitri Nikas
South Jersey Gas Co. (BBB+/Stable/--)	
At June 30, 2006, credit measures were appropriate for the current rating, with adjusted debt to capital of about 55%, FFO interest coverage of about 3.5x, and adjusted FFO to total debt of 14%. Over the near term, financial ratios should remain appropriate for the current ratings, with continued ratings stability dependent on a moderate proportion of capital spending on unregulated pursuits, prudent financing of growth strategies, and a greater portion of consolidated cash flow from the regulated gas utility.	Kenneth L. Farer
Southern California Edison Co. (BBB+/Stable/A-2)	
This utility's rating will continue to reflect the interplay between its affiliation with weaker, unregulated, competitive energy companies and the strong regulatory and statutory protections that limit the extent to which the regulated utility can be called upon to provide capital contributions to unregulated affiliates. The California Public Utilities Commission remains committed to providing relief in response to material changes in utility costs, which contributes to rating stability. The company's stand-alone adjusted cash flow coverage ratios were strong at June 30, 2006, with FFO interest coverage of 5.5x and FFO to total debt of 27% .	David Bodek
Southern California Gas Co. (A/Stable/A-1)	
The company continues to generate solid and predictable earnings and cash flows. FFO coverage of interest and debt stood at a very strong 6.4x and 32.1%, respectively, for the 12 months ended June 30, 2006. Credit concerns are minimal, with the utility in the midst of a $100 million to $200 million capex plan to build gas storage, compression, and transmission. Dividends to parent Sempra are expected to continue at the historical average.	Swami Venkataraman
Southern Co. (A/Stable/A-1)	
Retail kilowatt sales were up 2.5% for the first half of 2006 compared with first-half 2005, mostly from customer growth and weather-related factors. Customer growth was 1.3% for the year ended June 2006. Mississippi Power continues to evaluate several options to recover the costs to repair Hurricane Katrina damage, and federal grants could form part of the funding package. Adjusted funds from operations (FFO) interest coverage was 4.8x for the year ended	Terry Pratt

June 30, 2006, and should be around 5x through 2008.

Southern Connecticut Gas Co. (BBB+/Negative/--)	
See Energy East Corp.	Andrew Watt
Southern Electric Generating Co. (A/Stable/A-1)	
See Southern Co.	Terry Pratt
Southern Indiana Gas & Electric Co. (A-/Stable/--)	
See Vectren Corp.	Gerrit Jepsen
Southern Power Co. (BBB+/Stable/A-2)	
Southern Power's business risk profile has increased due to power plants in Florida and North Carolina that are not fully contracted and the initiation of construction activities for new assets. Favorable to credit are new long-term supply agreements in North Carolina and Florida, and success in securing replacement PPAs for capacity coming off of contract. For 2006 to 2008, FFO to interest coverage averages 3.6x, FFO to average total debt averages 19%, and leverage will remain slightly below 60%--assuming current acquisitions and contracts agreements close as planned. For the year ended June 30, 2006, FFO/interest coverage was 3.6x.	Terry Pratt
Southwest Gas Corp. (BBB-/Stable/--)	
Credit measures are solid for the rating, and as expected, have showed signs of improvement in 2006 with increased rate relief in Arizona. Southwest Gas' financial metrics showed *marked improvement for the first half of 2006, as the operating margin contribution of* continued customer growth and rate relief in Arizona offset the effects of another mild winter. On Feb. 15, 2006, the Arizona Corporation Commission authorized a $49.3 million rate increase, which was below management's request and implied an ROE of only 9.5%. Improving regulatory treatment in Nevada, where the company currently has a pending request for a weather-normalization adjustment mechanism, could further improve the company's regulatory profile.	Leo Carrillo
Southwestern Electric Power Co. (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
Southwestern Public Service Co. (BBB/Stable/A-2)	
See Xcel Energy Inc.	David Bodek
System Energy Resources Inc. (BBB-/Watch Neg/--)	
See Entergy Corp.	Dimitri Nikas
Tampa Electric Co. (BBB-/Stable/A-3)	
Tampa Electric Co.'s cash flow should benefit from deferred fuel cost recovery, partially funding elevated capital spending for environmental compliance and incremental peaking capacity. The utility's ratings are supported by strong customer growth, minimal reliance on industrial load, a strong regulated local gas distribution unit, and a supportive regulatory environment.	Jodi Hecht

TECO Energy Inc. (BB/Stable/B-1)	
TECO Energy Inc. has completed selling substanially all its merchant power assets and is refocusing on its core regulated business. Its utility, Tampa Electric, is concentrating on meeting the strong demand growth of its market. The company intends to build cash and refinance opportunistically ahead of sizable 2007 maturities. The idling of the synthetic fuel operations, which make up a substantial component of consolidated cash flow, reduced excess cash flow and slowed the pace of debt reduction. Debt incurred to pursue a merchant strategy continues to drag on financial measures and credit quality.	Jodi Hecht
Texas-New Mexico Power Co. (BBB/Negative/--)	
See PNM Resources Inc.	Chinelo Chidozie
Thermal North America Inc. (BB-/Stable/--)	
TNA continues to plan modifications to its credit agreement to manage a slight default in a leverage test, which occurred mainy due to exceptionally warm weather in early 2006. We continue to expect that overall cash flow will be reasonably stable with modest growth. Cash flow in second-quarter 2006 was also below forecasts due to adjustments to prior period results and lower earnings at Grey's Ferry. FFO to interest expenses was about 2.4x for the year ended June 30, 2006 (which includes operations before financial closure in October 2005).	Terry Pratt
Toledo Edison Co. (BBB/Stable/--)	
See FirstEnergy Corp.	Aneesh Prabhu
Tucson Electric Power Co. (BB/Stable/B-1)	
Strong cash flows are an important credit attribute of this very leveraged company, with parent UniSource expecting to fund rising capital expenditures internally and slowly work toward paying down Tucson Electric Power Co. debt and capital lease balances. Due to a rate cap in place through December 2008, TEP remains vulnerable to unplanned outages at its coal plants, but the units' strong performance this year so far, which are assisting a significant improvement in cash flow measures, is expected to continue through 2006. The Arizona Corporation Commission has initiated a proceeding to determine how TEP's rates will be set after the rate cap expires in 2008. Hearings are scheduled for January 2007.	Anne Selting
TXU Corp. (BBB-/Negative/--)	
The negative outlook continues to reflect the potential for a lower rating once the financial effects of TXU's planned $10 billion program to build 11 coal-fired power plants is factored into the consolidated rating. Retail customer counts continue to decline. For the 12 months ended June 30, 2006, adjusted FFO to interest was 5.1x and adjusted FFO to average total debt was 27.4x. However, leverage remains high compared with peers, as measured by an average total debt to total capital ratio of about 96%.	Terry Pratt
TXU Electric Delivery Co. (BBB-/Negative/--)	
See TXU Corp.	Terry Pratt
TXU Energy Co. LLC (BBB-/Negative/--)	
See TXU Corp.	Terry Pratt

TXU U.S. Holdings Co. (BBB-/Negative/--)	
See TXU Corp.	Terry Pratt
Union Electric Co. d/b/a AmerenUE (BBB-/Watch Neg/A-2)	
See Ameren Corp.	Barbara Eiseman
United Water New Jersey (A-/Watch Pos/--)	
See United Waterworks	Plana Lee
United Waterworks (A-/Watch Pos/--)	
If the combined entity were to spin off the United Water assets, United Water New Jersey's and United Waterworks' stand-alone credit quality could be in the 'BBB' rating category, particularly if intermediate parent United Water Inc. retains its riskier contract-management segment. The company's FFO interest coverage was 3.6x for the 12 months ending June 2006.	Plana Lee
Vectren Corp. (A-/Stable/--)	
Warmer-than-normal weather had a better impact on margins. Revenues have increased for all three utilities based on rate increases achieved during 2005. Unregulated activities continue to provide positive income at an arm's length and mostly support regulated operations. Interim financial ratios are in line with expectations and rating level.	Gerrit Jepsen
Vectren Utility Holdings Inc. (A-/Stable/A-2)	
See Vectren Corp.	Gerrit Jepsen
Virginia Electric & Power Co. (BBB/Stable/A-2)	
See Dominion Resources Inc	Aneesh Prabhu
Washington Gas Light Co. (AA-/Negative/A-1)	
See WGL Holdings Inc.	Jeanny Silva
West Penn Power Co. (BB+/Positive/--)	
See Allegheny Energy Inc.	Aneesh Prabhu
Westar Energy Inc. (BB+/Positive/--)	
Second-quarter results improved due to increased retail electric sales, higher rates, and lower interest expense. Key financial metrics also strengthened and are marginally commensurate with investment grade levels. The Kansas Court of Appeals' rejection in July 2006 of parts of the Kansas Corporation Commission's (KCC) December 2005 rate order could lead to a material rate reduction or customer refund, thereby affecting Westar's steady financial improvement. Westar has filed a petition for review with the Kansas Supreme Court. If the Supreme Court does not grant petitions for review or affirms the decision of the lower court, the case will go back to the KCC.	Barbara Eiseman
Western Massachusetts Electric Co. (BBB/Stable/--)	

See Northeast Utilities	Andrew Watt
WGL Holdings Inc. (AA-/Negative/A-1)	
We could lower ratings if WGL fails to implement a regulatory mechanism for reducing weather- and conservation-related volatility in Virginia, if capital spending for the pipeline rehabilitation project increases substantially over current estimates, or if the company's consolidated financial performance and liquidity position do not adequately offset the risk associated with retail energy marketing. During the 12 months ended June 2006, adjusted FFO to total debt (excluding pension adjustments) was 26%. Adjusted debt to capital (excluding pension adjustments) was 44%.	Jeanny Silva
Wisconsin Electric Power Co. (A-/Negative/A-2)	
See Wisconsin Energy Corp.	Gerrit Jepsen
Wisconsin Energy Corp. (BBB+/Negative/A-2)	
Wisconsin Energy's financial measures have been mixed for the rating during a heavy construction program, but there has been some improvement in cash flow protection measures following the last rate increase. Maintaining this improvement will depend highly on supportive rate treatment and prudent execution of the capital spending program.	Gerrit Jepsen
Wisconsin Gas LLC (A-/Negative/A-2)	
See Wisconsin Energy Corp.	Gerrit Jepsen
Wisconsin Power & Light Co. (A-/Stable/A-2)	
See Alliant Energy Corp.	Jeanny Silva
Wisconsin Public Service Corp. (A/Watch Neg/A-1)	
See WPS Resources Corp.	Jeanny Silva
WPS Resources Corp. (A/Watch Neg/A-1)	
WPS was placed on Watch negative after announcing it planned to merge with lower-rated Peoples Energy Corp. The potential stock-for-stock merger presents the following concerns: higher regulatory risk (Peoples operates in the currently politically volatile Illinois market), the potential for additional energy marketing activities, exposure to oil and gas exploration and production activities, and additional integration risk. High leverage at Peoples Energy, and WPS' commitment to increase the dividend paid to current WPS shareholders by 16.8% also pressure ratings. WPS's adjusted credit metrics are currently very weak for the rating (reflecting high levels of short-term leverage), with adjusted FFO to total debt for the 12 months ended June 2006 at about 10% (including pension adjustments).	Jeanny Silva
Xcel Energy Inc. (BBB/Stable/A-2)	
Xcel Energy's several subsidiaries are engaged in numerous rate proceedings that will be important determinants of future credit quality. The consolidated cash flow coverages remain very steady as of June 30, 2006, with FFO interest coverage of 3.4x and FFO to total debt of about 16%.	David Bodek
Yankee Gas Services Co. (BBB/Stable/--)	
See Northeast Utilities	Andrew Watt

York Water Co. (The) (A-/Stable/--)

The company continues to grow organically and through small acquisitions. The use of proceeds from the expected issuance of equity and long-term debt later in 2006 to repay short-term debt should strengthen credit metrics. However, upward rating potential in the near term is unlikely, given the company's lack of free cash flow and substantial capital expenditures expected in 2006. The company's FFO interest coverage was 3.2x for the 12 months ending June 2006. Plana Lee

*Ratings are as of Oct. 25, 2006.

Quarterly Rating Activity

Table 2

Recent Rating/Outlook/CreditWatch Actions

Issuer	To	From	Date	Reason
Ameren Corp.	BBB/Watch Neg/A-3	BBB+/Watch Neg/A-2	Oct. 5, 2006	The rating action on CIPS, CILCORP, CILCO, and IPC (the Illinois utilities) reflects serious concern over the financial health of these companies that possible legislation mandating an electric rate freeze extension of up to three years has raised. Lower ratings on Ameren, UE, and AEGC reflect deterioration in the consolidated business profile and financial metrics, which were somewhat subpar for the previous rating level, compounded by the stress of near-term weakening of the Illinois utilities, which account for roughly 30% of Ameren's funds from operations and operating income. Also of concern is the credit exposure of power suppliers to the Illinois utilities. Under Illinois' restructuring law, generators are unable to require collateral postings from the utilities as credit quality deteriorates. Therefore, in the event of a utility insolvency, AEGC could face a liquidity crunch.
AmerenEnergy Generating Co.	BBB-/Watch Neg/--	BBB+/Watch Neg/--	Oct. 5, 2006	See Ameren Corp.
Aquila Inc.	B/Watch Pos/B-2	B-/Watch Pos/B-3	Sept. 1, 2006	The upgrade reflects the company's improved business risk profile, significant debt reduction and plans for further deleveraging, expected cash-flow improvement, and lower ongoing working capital requirements.
Atlantic City Electric Co.	BBB/Stable/A-2	BBB+/Watch Neg/A-2	Aug. 7, 2006	See PEPCO Holdings Inc.

Baltimore Gas & Electric Co.	BBB+/Watch Pos/A-2	BBB+/Watch Dev/A-2	Sept. 14, 2006	See Constellation Energy Group Inc.
Carolina Power & Light Co d/b/a Progress Energy Carolinas Inc	BBB/Positive/A-2	BBB/Stable/A-2	July 25, 2006	See Progress Energy Inc.
Central Illinois Light Co.	BBB-/Watch Neg/--	BBB+/Watch Neg/--	Oct. 5, 2006	See Ameren Corp.
Central Illinois Public Service Co.	BBB-/Watch Neg/--	BBB+/Watch Neg/--	Oct. 5, 2006	See Ameren Corp.
CILCORP Inc.	BBB-/Watch Neg/--	BBB+/Watch Neg/--	Oct. 5, 2006	See Ameren Corp.
Commonwealth Edison Co.	BBB-/Watch Neg/A-3	BBB+/Watch Neg/A-2	Oct. 5, 2006	See Ameren Corp.
Constellation Energy Group Inc.	BBB+/Watch Pos/A-2	BBB+/Watch Dev/A-2	Sept. 14, 2006	The CreditWatch implications revision followed the completion of our annual review of the company and its conclusion that the company's current credit profile is 'BBB+' and is not likely to fall in the near term. The revision is not based on our expectation of a successful merger with the FPL Group; however, if consummated, this merger could result in higher ratings, thus the positive CreditWatch.
Dayton Power & Light Co.	BB+/Positive/--	BB/Positive/--	Aug. 1, 2006	See DPL Inc.
Delmarva Power & Light Co.	BBB/Stable/A-2	BBB+/Watch Neg/A-2	Aug. 7, 2006	See PEPCO Holdings Inc.
DPL Inc.	BB+/Positive/--	BB/Positive/--	Aug. 1, 2006	The rating action incorporates the company's continued improvement in its financial profile with the reduction of about $450 million of debt and improved cash flow generation from its its core utility operations as well as its focus on improving its internal control and past corporate governance issues.
Duke Capital LLC	BBB/Positive/A-2	BBB/Developing/A-2	Sept. 13, 2006	The rating action on Duke Energy and Duke Capital reflects the assessment of Duke Energy's proposed separation of the natural gas transmission, distribution, and processing operations into a separate

				entity through a tax-free spin-off effective Jan. 1, 2007, which could result in higher ratings of up to two notches from current levels for the newly created gas company. When the new gas company is created, it is expected that the senior unsecured debt rating on Duke Capital will be one notch below the final corporate credit rating.
Dynegy Holdings Inc.	B/Watch Dev/--	B/Stable/--	Sept. 18, 2006	See Dynegy Holdings Inc.
Dynegy Inc.	B/Watch Dev/B-2	B/Stable/B-2	Sept. 18, 2006	The CreditWatch placement follows Dynegy's announcement that it will acquire the assets of LS Power Group, a privately held power plant investor, developer, and manager and acquire a 50% interest in a project development joint venture with LS Power. Under the terms of the transaction, LS Power will receive 340 million shares of Dynegy common stock plus $100 million in cash and a $275 million Dynegy junior subordinated note. The combined entity will also assume about $1.8 billion in net debt from LS Power.
Edison International	BBB-/Stable/--	BBB/Stable/--	Sept. 29, 2006	The rating on Rosemead, Calif.-based holding company Edison International was lowered to reflect the company's strategic shift, whereby management has revised the company's objectives to __ _ facilitate the pursuit of growth opportunities available to the unregulated members of the Edison family of companies and to benefit shareholders. The first evidence of the implementation of this strategic shift can be found in Edison Capital's April 2006 contribution to Mission Energy Holding Co. of its ownership interests in wind projects and a biomass project with an aggregate book value of about $76 million.
Edison Mission Energy	BB-/Positive/--	B+/Positive/--	Sept. 29, 2006	The upgrades reflect the movement of the affected companies' credit quality toward the consolidated Edison International companies' credit quality. The rating upgrades coincide with the downgrade of Edison International to 'BBB-' from 'BBB'. The rating action on Edison International also reflects the movement toward a consolidated credit profile of the parent and its unregulated subsidiaries.
Edison Mission	BB-/Positive/--	B+/Positive/--	Sept.	See Edison Mission Energy

Energy Funding Corp.			29, 2006	
Edison Mission Marketing and Trading	*BB-/Positive/--*	*B+/Positive/--*	*Sept. 29, 2006*	*See Edison Mission Energy*
Entergy Arkansas Inc.	BBB/Negative/--	BBB/Watch Neg/--	July 20, 2006	See Entergy Corp.
Entergy Corp.	BBB/Negative/--	BBB/Watch Neg/--	July 20, 2006	The ratings affirmation recognizes the increased probability that Entergy will recover a substantial portion of hurricane-related storm costs incurred in 2005. Still, uncertainty exists regarding the ultimate level and timing of the recovery, which is reflected in the negative outlook. The negative outlook also reflects increasing pressure on the consolidated company's business profile from regulatory challenges in several jurisdictions combined and a larger portion of assets being involved in nonregulated ventures such as the firm's recent announcement to purchase the Palisades nuclear plant from Consumers Energy Co.
Entergy Gulf States Inc.	BBB/Negative/--	BBB/Watch Neg/--	July 20, 2006	See Entergy Corp.
Entergy Louisiana Capital I	BBB/Negative/--	BBB/Watch Neg/--	July 20, 2006	See Entergy Corp.
Entergy Louisiana Holdings Inc.	BBB/Negative/--	BBB/Watch Neg/--	July 20, 2006	See Entergy Corp.
Entergy Louisiana LLC	BBB/Negative/--	BBB/Watch Neg/--	July 20, 2006	See Entergy Corp.
Entergy Mississippi Inc.	BBB/Negative/--	BBB/Watch Neg/--	July 20, 2006	See Entergy Corp.
Exelon Corp.	BBB+/Stable/A-2	BBB+/Watch Neg/A-2	Sept. 15, 2006	The CreditWatch resolution follows Exelon's announcement that it has terminated its merger agreement with lower-rated Public Service Enterprise Group Inc.
Florida Power Corp d/b/a Progress Energy Florida Inc	BBB/Positive/A-2	BBB/Stable/A-2	July 25, 2006	See Progress Energy Inc.
Florida	BBB/Positive/A-2	BBB/Stable/A-2	July	See Progress Energy Inc.

Progress Corp.			25, 2006	
Illinois Power Co.	BBB-/Watch Neg/--	BBB+/Watch Neg/--	Oct. 5, 2006	See Ameren Corp.
Midwest Generation LLC	BB-/Positive/--	B+/Positive/--	Sept. 29, 2006	See Edison Mission Energy
Mirant Americas Generating LLC	B+/Watch Neg	B+/Stable/--	July 11, 2006	See Mirant Corp.
Mirant Corp.	B+/Watch Neg	B+/Stable/--	July 11, 2006	The CreditWatch listing followed Mirant's announcement that they will buy back up to 43 million common shares with cash on hand and cash to be freed up from a near-term recapitalization of its Philippines business. Mirant also announced that its Philippines and Caribbean businesses will be sold through an auction process. The use of cash to buy back the company's common stock will reduce Mirant's liquidity position to levels below those established when the company emerged from bankruptcy in late 2005.
Mirant Mid-Atlantic LLC	B+/Watch Neg	B+/Stable/--	July 11, 2006	See Mirant Corp.
Mirant North America LLC	B+/Watch Neg	B+/Stable/--	July 11, 2006	See Mirant Corp.
Mission Energy Holding Co.	B/Positive/--	B-/Positive/--	Sept. 29, 2006	See Edison Mission Energy
Nevada Power Co.	BB-/Stable/--	B+/Stable/--	Sept. 22, 2006	See Sierra Pacific Resources
PEPCO Holdings Inc.	BBB/Stable/A-2	BBB+/Watch Neg/A-2	Aug. 7, 2006	The downgrade reflects our view that regulatory risk is increasing, and that financial measures that have historically been weak for the rating level are not expected to improve to levels commensurate with a 'BBB+' rating in the near term.
Potomac Capital Investment Corp.	BBB-/Stable/--	BBB/Watch Neg/--	Aug. 7, 2006	See PEPCO Holdings Inc.
Potomac	BBB/Stable/A-2	BBB+/Watch Neg/A-2	Aug.	See PEPCO Holdings Inc.

Electric Power Co.			7, 2006	
Progress Energy Inc.	BBB/Positive/A-2	BBB/Stable/A-2	July 25, 2006	The outlook revision reflects the company's progress in reducing debt levels at the holding company and expects future financial performance to achieve 'BBB+' financial benchmarks.
PSE&G Capital Trust I	BBB/Negative/--	BBB/Watch Dev/--	Sept. 15, 2006	See Public Service Enterprise Group
PSEG Power LLC	BBB/Negative/--	BBB/Watch Dev/--	Sept. 15, 2006	See Public Service Enterprise Group
Public Service Electric & Gas Co.	BBB/Negative/--	BBB/Watch Dev/--	Sept. 15, 2006	See Public Service Enterprise Group
Public Service Enterprise Group Inc.	BBB/Negative/--	BBB/Watch Dev/--	Sept. 15, 2006	We affirmed our 'BBB' corporate credit rating on diversified energy company Public Service Enterprise Group and its units, PSEG Power and Public Service Electric & Gas Co. following the termination of its merger agreement with Exelon Corp.
Sierra Pacific Power Capital I	BB-/Stable/--	B+/Stable/--	Sept. 22, 2006	See Sierra Pacific Resources
Sierra Pacific Power Co.	BB-/Stable/--	B+/Stable/--	Sept. 22, 2006	See Sierra Pacific Resources
Sierra Pacific Resources	BB-/Stable/--	B+/Stable/--	Sept. 22, 2006	The raised rating reflects the cumulative impact of a substantially improved regulatory relationship with the Public Utilities Commission of Nevada (PUCN), improved liquidity, asset acquisitions that have significantly reduced the utilities' short capacity and energy position, and financial restructuring that included conversion of more than $500 million of hybrid securities into equity in 2005, the recent issue of $280 million in new equity, and the pushing out of debt maturities into later years. Standard & Poor's also viewed favorably, and factored into the rating, the expected recovery of $180 million in deferred costs that were disallowed in 2002.
System Energy Resources Inc.	BBB/Negative/--	BBB/Watch Neg/--	July 20, 2006	See Entergy Corp.
Union Electric	BBB/Watch Neg/A-3	BBB+/Watch Neg/A-2	Oct.	See Ameren Corp.

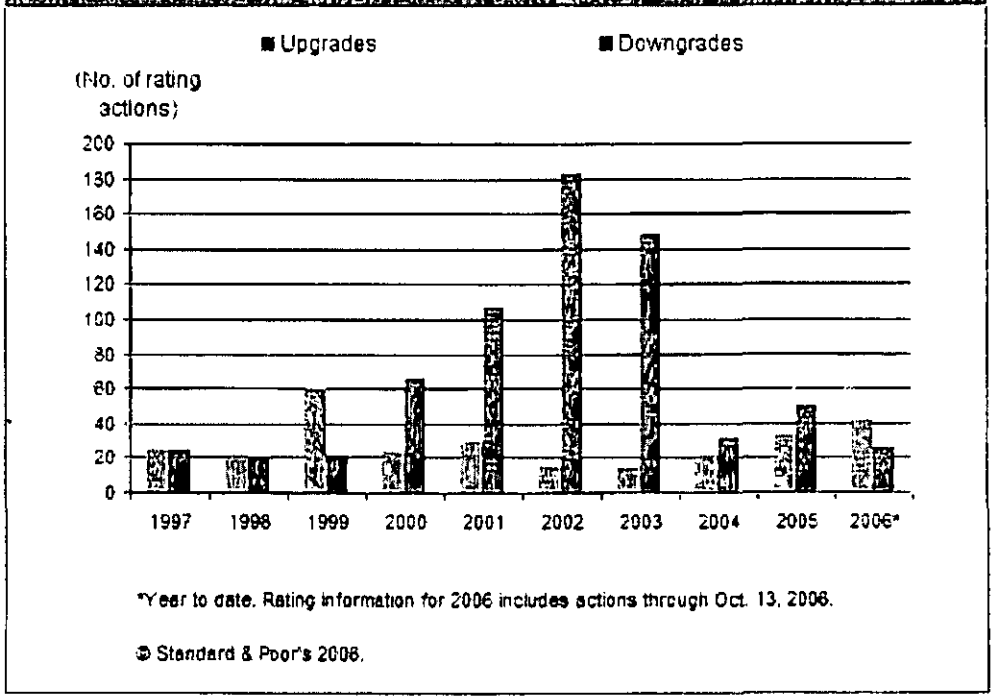
Co. d/b/a AmerenUE			5, 2006	
Wisconsin Public Service Corp.	A/Watch Neg/A-1	A/Negative/A-1	July 10, 2006	See WPS Resources Corp.
WPS Resources Corp.	A/Watch Neg/A-1	A/Negative/A-1	July 10, 2006	The rating action was in response to the announced stock-for-stock merger between WPS Resources and lower-rated diversified energy company Peoples Energy Corp. The CreditWatch listing on WPS reflects concerns that the company's credit profile will be pressured by the following post-merger factors: introduction to the challenging Illinois regulatory environment, heightened exposure to energy marketing activities, exposure to the volatile oil and gas exploration and production sector, high leverage at Peoples Energy, and a commitment to increase the dividend paid to current WPS shareholders by 16.8%.

*Dates represent the period from July 10, 2006 through Oct. 25, covered by this report card.

Ratings Trends

Chart 3

U.S. Utility Upgrades Versus Downgrades



Selected Articles

Table 3

Previously Published Electric/Gas/Water Utilities Articles

Article title	Published date
Credit FAQ: Could Power Outages At Consolidated Edison Dim Its Ratings?	Aug. 22, 2006
Credit FAQ: Missouri's New Power Cost Recovery Rules Should Bolster Utilities' Credit Quality	Sept. 29, 2006
Credit FAQ: S&P Introduces Reconciliation Tables To Show Analytical Adjustments To Global Utilities' Financial Statements	Oct. 11, 2006
Credit FAQ: What Assets Sales And A Stock Buy-Back Mean For Mirant Corp.'s Ratings	Aug. 31, 2006
Criteria: S&P Updates U.S. Merchant Power Rating Methodology And Power Price Assumptions	Aug. 24, 2006
Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers	Sept. 14, 2006
Key Rating Factors For Water Companies Around The World	July 17, 2006
Proposed New Long-Term Capacity Markets In The Eastern U.S. Are Favorable For Electric	Sept. 15,

Generators	2006
Recovery Report: Regency Gas Services' Proposed $850 Million Senior Secured Credit Facility	July 13, 2006
Right-Way Risk Can Enhance Hedging Capabilities Of Higher-Risk U.S. Energy Companies	Sept. 11, 2006
Tucson Electric Power's Risks Of Meeting Summer Peaks Offset By Its Coal Fleet	July 13, 2006
U.S. Public Power Utilities' Self-Governance Bolsters Credit Quality	July 19, 2006

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Table 4

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Comments and ratings reflect available public data as of Oct. 25, 2006.

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Moody's Investors Service

Global Credit Research
Credit Opinion
21 DEC 2006

Credit Opinion: Hawaiian Electric Company, Inc.

Hawaiian Electric Company, Inc.

Honolulu, Hawaii, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
Preferred Stock	Baa3
Bkd Commercial Paper	P-2
Parent: Hawaiian Electric Industries, Inc.	
Outlook	Stable
Senior Unsecured	Baa2
Bkd Commercial Paper	P-2
HECO Capital Trust III	
Outlook	Stable
Bkd Preferred Stock	Baa2

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William L. Hess/New York	

Key Indicators

Hawaiian Electric Company, Inc.

	Q306LTM	2005	2004	2003	2002
(CFO Pre-W/C + Interest) / Interest	4.4	4.7	4.6	4.5	4.4
(CFO Pre-W/C) / Debt	19.5%	19.5%	20.2%	22.0%	21.2%
(CFO Pre-W/C - Dvidends) / Debt	15.0%	14.5%	18.9%	14.5%	15.5%
(CFO Pre-W/C - Dvidends) / Capex	73.2%	68.7%	87.2%	88.1%	124.7%
Debt / Book Capitalization	49.2%	49.6%	47.1%	47.6%	49.6%
EBITDA Margin	8.2%	8.8%	10.6%	12.9%	16.4%

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Company Profile

Hawaiian Electric Company, Inc. (HECO) and its operating subsidiaries, Maui Electric Company, Limited (MECO) and Hawaii Electric Light Company, Inc. (HELCO) are regulated electric public utilities that provide electricity to 95% of the state's 1.2 million residents on the islands of Oahu, Maui, Hawaii, Lanai and Molokai. HECO serves the island of Oahu; MECO serves the islands of Maui, Molokai, and Lanai; and HELCO serves the island of Hawaii. HECO is a wholly-owned subsidiary of Hawaiian Electric Industries, Inc.

Rating Rationale

HECO's Baa1 Issuer Rating reflects the relative earnings and cash flow stability of this vertically integrated utility, the relatively strong service territory growth that continues at HECO and its subsidiaries, the company's conservative financial management, including its back-to-basics business strategy, and the historically strong financial metrics that have resulted for this medium size utility. The rating also considers the increasing size of the company's capital programs, the need for timely regulatory support to help finance capital investment and to

maintain credit quality, and the associated challenges to implement rate increases in a state where retail electric rates are high.

Key Credit Factors

1. Historically, HECO has produced relatively stable credit metrics.

HECO has historically been a stable producer of earnings and cash flow due to its position as a vertically integrated utility that serves 95% of the state, a growing service territory, and the receipt of incremental rate relief, including the September 2005 interim rate decision from the Hawaii Public Utilities Commission (Hawaii PUC). For the past three years, HECO's ratio of cash flow to adjusted debt has averaged around 20% and the ratio of cash flow to adjusted interest has averaged around 4.5 times over the same period. These financial measures, which incorporate Moody's standard adjustments, are consistent with a high Baa rated vertically-integrated utility and are in accordance with the guidelines in Moody's rating methodology for electric utilities in the mid-range of the medium global risk category.

2. Relatively strong service territory growth that continues to diversify

During 2005, the state's economy grew by 4.0% and it is expected to grow at around 3.3% for 2006. Economic growth continues to be fueled by strength in the tourism sector and from growth by the federal government. 2005 was a record year for tourism in Hawaii, with visitor days exceeding the 2004 record by 7.7%. For the first eight months of 2006, visitor days were relatively flat compared to the same period for 2005, but expenditures were up 4.5%. In recent years, the growth of federal government spending, principally military spending, has caused the Hawaiian economy to become less dependent upon tourism as a principal source of economic expansion. For example, total federal government expenditures in Hawaii, including military expenditures, were $12.2 billion in fiscal year 2004, an increase of 8% over fiscal year 2003. Military spending, which is 39% of federal expenditures in Hawaii, increased 6% in fiscal year 2004 compared to fiscal year 2003.

3. Regulatory Support Remains Critical to Maintenance of Credit Quality

As noted in Moody's Rating Methodology for Global Regulated Electric Utilities, the supportiveness of the regulatory framework under which a utility operates is a critical rating factor. While regulatory decisions rendered by the Hawaii PUC have generally resulted in supportive outcomes, Moody's notes an increasing degree of regulatory lag that exists in reaching final decisions in Hawaii. For example, HECO is still operating under an interim order reached in September 2005 and along with subsidiaries, MECO and HELCO, have either filed or intend to file additional rate requests in the near future due to the need to recover higher operating expenses. Additionally, supply and reliability related issues have surfaced throughout the state due to the growth in the economy and the age and inefficiency of some of the existing resources in the state. Given the increasing need for additional generation and reliability related resources, timely and supportive regulatory decisions remain key to the maintenance of HECO's credit quality.

4. Capital Programs for Utility Infrastructure Has Increased.

Capital expenditures for 2004 and 2005 exceeded $200 million annually and capital expenditures for 2006 are expected to be in a similar range. Most of the capital investment has been associated with transmission and distribution investments as well as new generation resources, all intended to meet growing demand and to improve reliability and supply options that exist on an aging electric system. HECO has also invested heavily in demand side management programs that are intended to reduce consumption and head off the need for additional peak time resources. Reflective of this capital investment requirement has been HECO's increase in operation and maintenance expense associated with their need to operate older, less efficient generation more frequently in order to satisfy higher demand requirements. HECO and its subsidiaries' ability to obtain timely and supportive regulatory treatment for its capital investment program remains an important rating consideration.

Rating Outlook

HECO's stable rating outlook reflects an expectation that the company will continue to manage its growth in a conservative fashion, that timely regulatory support for the company's sizeable capital program will occur, and that management will remain focused around its current back-to-basics business strategy.

What Could Change the Rating - Up

In light of the sizeable capital investment programs and the uncertainty that surrounds associated rate case decisions and rate requests contemplated by HECO and its subsidiaries, limited near-term prospects exist for the rating to be upgraded.

What Could Change the Rating - Down

The rating could be downgraded should weaker than expected regulatory support emerge, including the

continuation of regulatory lag, which ultimately causes earnings and sustainable cash flow to suffer.

Rating Factors

Hawaiian Electric Company, Inc.

Select Key Ratios for Global Regulated Electric Utilities

Rating	Aa	Aa	A	A	Baa	Baa	Ba	Ba
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**
CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-70	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

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STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Summary:

Hawaiian Electric Company, Inc.

Publication date: 22-Nov-2006
Primary Credit Analyst: Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com

Credit Rating: BBB+/Negative/A-2

Rationale

The ratings on Hawaiian Electric Co. Inc. are based on the consolidated credit profile of Hawaiian Electric Industries, Inc. (HEI), which includes Hawaiian Electric's utility operations and its two subsidiaries Hawaiian Electric Light Co. (HELCO) and Maui Electric Co. (82% of core revenues and 61% of operating income as of Dec. 31, 2005), and the riskier financial services operations of American Savings Bank FSB, (18% of core revenues and 39% of operating income). Standard & Poor's Ratings Services does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI.

HEI's consolidated financial condition remains somewhat weak for the rating despite the strong Hawaiian economy and the company's efforts in recent years to strengthen its capital structure. On a stand-alone basis, Hawaiian Electric has a healthier financial profile owing to a lower debt burden. Financial metrics have been pressured owing to rising operating and maintenance expenses, increasing capital outlays, the prolonged lack of rate relief, and recently, lower electricity sales caused by cooler less humid weather and customer conservation. Absent a responsive final rate order in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.

HEI and Hawaiian Electric have satisfactory business profiles of '6' and '5', respectively, (business profiles are ranked from '1' (excellent) to '10' (vulnerable)) and somewhat weak financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, a currently excellent fuel clause, and relatively steady banking operations. The bank's decent earnings are driven by net interest income from its low-risk earning-asset base, funded largely by a good deposit franchise. These strengths are tempered by Hawaii's economic dependence on a limited number of industries, reliance on fuel oil, significant purchased power obligations, and support of the somewhat riskier banking business. Hawaiian Electric's business profile is slightly stronger than that of the parent due to the absence of nonutility operations.

A responsive final rate order from the Hawaii Public Utilities Commission (PUC) with regard to Hawaiian Electric's pending rate case is crucial to help lift key financial measures to more appropriate levels for the ratings. In September 2005, the PUC issued an interim net rate hike of $41.1 million (3.3%) that is marginally supportive of current ratings. If the amount collected under the interim increase exceeds the amount of the increase ultimately approved in the PUC's final decision and order, the company must refund the excess to its ratepayers with interest. A final order that closely mirrors the interim ruling appears to be sufficient to lift key financial metrics to levels that are marginally suitable for Standard & Poor's guideposts for the 'BBB' rating category. There are no time restrictions in which the PUC must issue a final order. Furthermore, pending before the PUC is HELCO's request for a $29.9 million (9.2%) rate increase. An interim decision is expected in the second quarter of 2007.

Of some concern is Hawaii's Act 162, a new law which appears to confirm, in light of the state legislature's interest in promoting renewable energy, the PUC's ability to authorize the utility's fuel adjustment clause. Although no parties to the rate case seem to oppose the continuation of the clause, a material change to fuel-adjustment mechanism would harm the company's financial condition and detract from its currently

satisfactory business profile.

Hawaii's economy grew by about 3.4% in 2005 and is expected to grow by 2.7% in 2006. Military and federal government spending remains strong as the U.S. Department of Defense has moved military assets to Hawaii. Tourism is also a significant component of the Hawaii economy, with visitor days and visitor expenditures up 7.7% and 9.6%, respectively in 2005. Continued growth is expected in 2006, with projected increases of 2.8% in visitor days and 7.1% in visitor expenditures. Although the housing market appears to be stabilizing, the construction industry continues to be healthy. However, future growth in residential construction may slow with rising interest rates. Hawaii's economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending, yet remains vulnerable to uncertainties in the world's geopolitical environment.

Hawaiian Electric's projected $912 million capital outlays over the next five years will focus predominantly on additions and improvements to transmission and distribution facilities (approximately 51%) and on generation projects (approximately 41%). The balance is for general plant, energy solutions, and customer-choice technologies. Although the bulk of construction expenditures will continue to be funded internally, the company's larger investment in reliability projects will result in increased reliance on outside capital.

HEI has certain bondholder protection metrics that are subpar for the current ratings. In this regard, total debt to capital (adjusted for off-balance-sheet obligations, such as purchased-power contracts and trust-originated preferred securities) and funds from operations (FFO) to total debt are somewhat weak at about 57% and 17%, respectively. Adjusted FFO interest coverage remains healthy at roughly 3.8. Accordingly, a supportive final rate order, tight cost controls, improved earnings, and credit supportive actions by management will be required to lift the company's overall financial profile to more suitable levels.

Short-term credit factors

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2', incorporating solid liquidity, a manageable maturity ladder, and the ability to internally fund a large portion of dividends and capital expenditures in nearby years.

HEI maintains a $100 million unsecured revolving credit facility that expires on March 31, 2011. The covenants require HEI to maintain a nonconsolidated capitalization ratio of 50% or less and consolidated net worth of $850 million. The company is comfortably in compliance with these covenants. HEI used the aforementioned facility to support the issuance of commercial paper to refinance its $100 million of medium-term notes which matured on April 10, 2006. In August 2006, HEI permanently funded the maturity with medium-term notes and terminated a $75 million unsecured bilateral revolver. Effective April 3, 2006, Hawaiian Electric entered into a $175 million revolver that expires on March 29, 2007, but will automatically extend to five years if the longer-term agreement is approved by the PUC. Pursuant to the agreement, the company must maintain a consolidated common stock equity to capitalization ratio of at least 35%, with which the company is in compliance.

Both HEI's and Hawaiian Electric's facilities support the issuance of commercial paper, but may also be drawn for general corporate purposes. Hawaiian Electric's facility may also be drawn for capital expenditures. The facilities do not contain interest coverage ratio requirements, material adverse change clauses, nor rating triggers. As of Oct. 31, 2006, both HEI's and Hawaiian Electric's credit facilities were undrawn.

HEI has a manageable maturity ladder, with just $10 million due in 2007. Hawaiian Electric has no maturing long-term debt until 2012. As of Sept. 30, 2006, HEI had $6.8 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents).

Standard & Poor's expects about three-quarters of Hawaiian Electric's 2006 construction program to be internally funded. Accelerating capital expenditures may necessitate a somewhat higher reliance on outside capital in 2007. In order to strengthen its balance sheet and support its capital program, Hawaiian Electric is not paying dividends to HEI in the second half of 2006. Importantly, ongoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows. The decrease in

Hawaiian Electric's dividend to HEI is expected to be partly offset by the increase in the bank's dividend. In the third quarter of 2006 the bank began, and plans to continue, to pay nearly all of its earnings as dividends to HEI while maintaining its target core capital ratio of 7.5% and still supporting its own business growth.

HEI has $50 million of debt capacity remaining under a Rule 415 shelf registration and $96 million remains on an omnibus shelf registration.

Outlook

The negative outlook on Hawaiian Electric mirrors that of parent HEI and reflects a subpar consolidated financial condition relative to the rating level. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaiian economy, a punitive final rate order, and, although not expected, a major erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit-supportive actions by the company as well as responsive rate treatment would lead to ratings stability.

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RESEARCH

Return to Regular Format

Industry Report Card:

Despite Demands For Increased Capital Spending, U.S. Utility Ratings Should Remain Stable

Publication date: 12-Jan-2007
Primary Credit Analyst: Richard W Cortright, Jr., New York (1) 212-438-7665; richard_cortright@standardandpoors.com

Key Credit Trends

The U.S. utility industry demonstrated stable credit quality in the fourth quarter of 2006, and should continue to do so in 2007 despite increasing capital spending needs related to reliability enhancements and environmental requirements. A general refocus by the industry in recent years on restoring balance sheet health and selling noncore business operations has enhanced its ability to withstand the pressure that substantial capital spending will bring.

A critical element during this coming growth phase, however, will be fair and equitable treatment by state regulators as utilities seek to recover the capital expenditures they will incur to address declining reserve margins, aging and increasingly fragile infrastructure, and environmental mandates. Standard & Poor's Ratings Services expects that most utilities will seek pre-approval from regulators of any substantial spending program, or at least a broad understanding of the principles that regulators will apply in granting recovery. Of comparable significance to supporting credit quality is regulatory approval for timely recovery of fuel costs, especially in an environment of elevated commodity prices.

With 57% of the industry carrying a stable outlook, we expect rating changes to remain low in 2007. What could cause this assessment to change would be event risk, specifically, an acceleration of merger and acquisition activity despite the collapse in 2006 of two high profile combinations between Exelon Corp. (BBB+/Watch Neg/A-2) and Public Service Enterprise Group Inc. (BBB/Negative/A-3) and between Constellation Energy Group Inc. (BBB+/Negative/A-2) and FPL Group Inc. (A/Stable/--). M&A could ultimately have a significant but uncertain impact on rating movements, which will depend on how the transactions are financed and the credit quality of the respective parties prior to the merger. Long-term private equity and financial buyers could be major influences in this respect, though it is too early to determine whether a trend has been established by the deals between Macquarie Infrastructure Partners and Duquesne Light Holdings Inc. (BBB/Watch Neg/--), Babcock & Brown Infrastructure Ltd. and NorthWestern Corp. (BB+/Watch Neg/--), and Berkshire Hathaway Inc. (AAA/Stable/A-1+) and PacifiCorp (A-Stable/A-1) that were announced or closed in 2006.

Despite earlier fireworks, 2006 ends with a fizzle

Since we published our last utility report card on Oct. 25, 2006, Standard & Poor's has made no rating upgrades or downgrades among electric, gas, and water utilities. The entire year had 21 upgrades and 20 downgrades.

Following the third quarter's very notable events, specifically, the dissolution of the merger agreement between Exelon and Public Service Enterprise Group and political developments regarding the end of the

rate freeze in Illinois, and the many rating actions that followed, the fourth quarter was in all respects very quiet.

In late November, the Illinois state legislature's special session to consider extending for three years the current long-lived electric rate freeze for all the state's utilities failed to garner the necessary votes. Passage of such an extension would have resulted in a serious cash shortfall for the utilities because the costs they would incur to procure power would exceed the rates they would be allowed to charge customers for that power. Because no lawmaker has thus far proposed any alternative mechanisms to recover these costs, an extension would threaten the utilities' financial viability in relatively short order. In a follow-up special session in early January 2007, the legislature again failed to pass rate freeze legislation.

Merger attempts and legal battles also marked the U.S. merchant power industry in 2006
As with the utility sector, we have not changed any ratings in the merchant power sector since our last report card. What could change this in 2007 and beyond is a general consolidation among merchant generators, which we expect will occur despite the failure of Mirant Corp.'s (B+/Watch Neg/--) proposed hostile takeover of NRG Energy Inc. (B+/Stable/B-2) earlier in 2006.

Also, late in the fourth quarter, the U.S. 9th Circuit Court of Appeals gave new life to California's claims of price gouging by power suppliers that entered into energy contracts with the state at the height of the 2000-2001 energy crisis. In its decision, the court found that FERC did not apply appropriate legal standards in assessing the reasonableness of the contracts. The 9th Circuit remanded the case to FERC for further review of the contracts. If California prevails, it could have meaningful implications for some of the generation companies, such as Sempra Energy (BBB+/Stable/A-2), that entered into contracts with California Department of Water Resources. However, many of the suppliers have already reached settlements with California and have made refund payments to the state. Those companies should be shielded from further liability because California provided releases to the generators as part of the settlements.

Chart 1

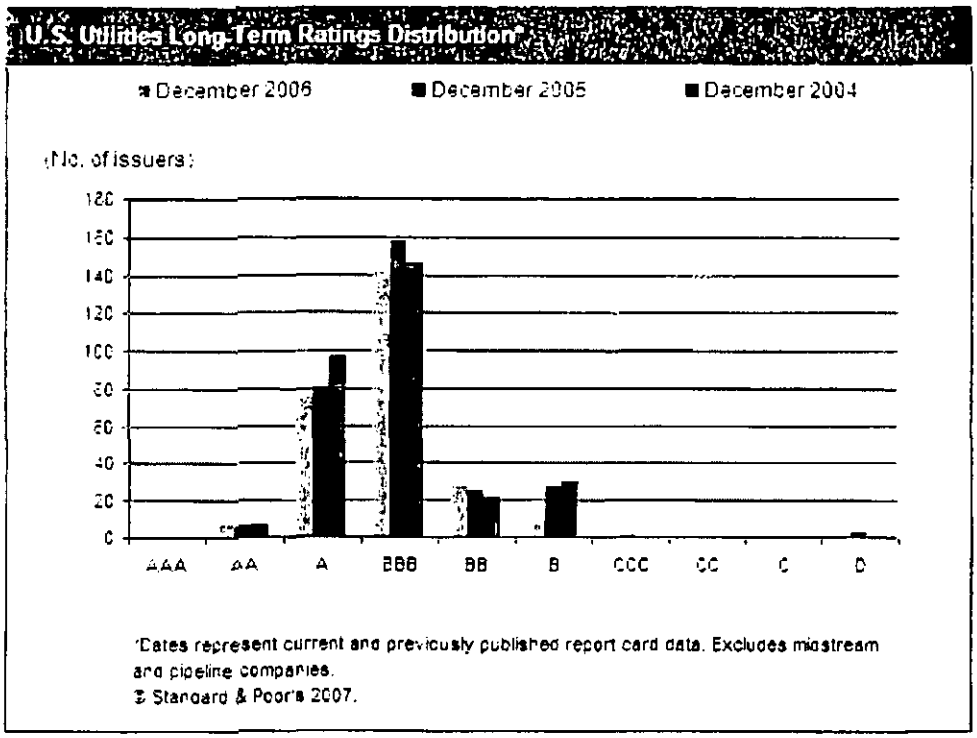
U.S. Utilities Long-Term Ratings Distribution*
December 2006
December 2005
December 2004
(No. of issuers)
180
160
140
120
100
80
60
40
20
0
AAA
AA
A
BBB
BB
B
CCC
CC
C
D
*Dates represent current and previously published report card data. Excludes midstream and pipeline companies.
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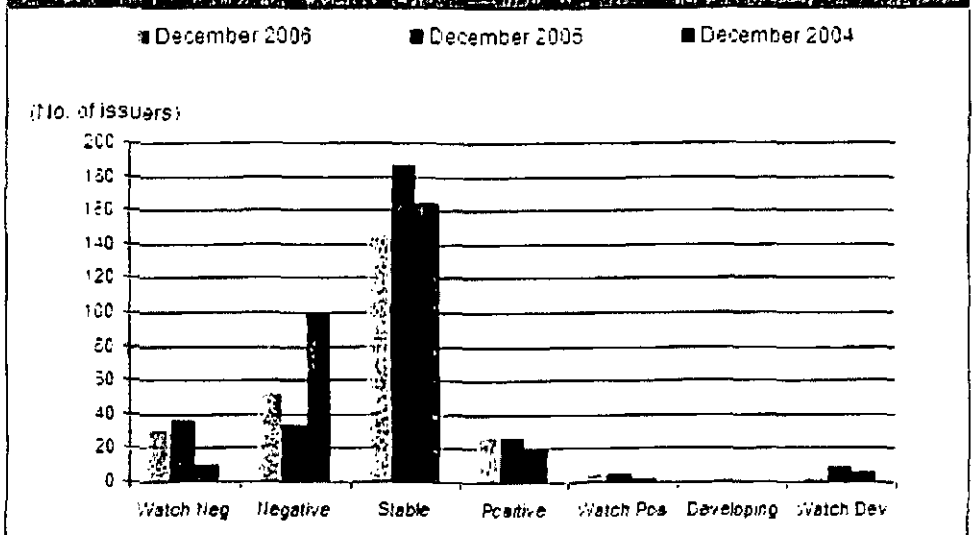
Chart 2

U.S. Utilities Outlook/CreditWatch Distribution*



*Dates represent current and previously published report card data. Excludes midstream and pipeline companies.

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Issuer Review

Table 1

Company/Corporate credit rating*/Comments	Analyst
AEP Texas Central Co. (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
AEP Texas North Co (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
AES Corp. (The) (BB-/Stable/--)	
We expect AES to continue to reduce parent-level debt, but also that deleveraging pace will slow. Parent-level debt to capital improved to 50% for the 12 months ended September 2006. Parent-level cash flow to debt and cash flow to interest also continued to trend positively, to 16% and 1.9x. AES' funding requirements for new projects remains large. We expect continued strong cash flows from the U.S. subsidiaries Indianapolis Power & Light Co. and AES Eastern Energy LLC to fund some projects, but issuing new debt will be needed. Monetization of some existing projects will fund large investments in alternate renewable energy. Liquidity has improved largely because AES Eastern now has its own financing arrangements for hedging purposes and does not rely on parent AES.	Aneesh Prabhu
AGL Resources Inc. (A-/Negative/A-2)	
On Dec. 7, 2006, AGL Resources announced the development of an additional 12 billion cubic feet of salt dome storage capacity in Beaumont, Texas. The $180 million project is expected to be partially financed with debt, but should not have any impact on ratings until 2010 when the facility is expected to come on line. Increased activity in the storage sector could pressure ratings if AGL were unable to contract the capacity to third parties and increased the seasonal arbitrage activities at its wholesale marketing subsidiary, Sequent Energy Management LP.	Michael Messer

Alabama Gas Corp. (BBB+/Stable/--)

See Energy East Corp. — Ralf DeCesare

Alabama Power Co. (A/Stable/A-1)

See Southern Co. — Terry Pratt

Allegheny Energy Inc. (BB+/Positive/--)

The company continues to make progress in restoring its financial profile through debt reduction and refinancing. Funds from operations (FFO) to debt and FFO to interest as of Sept. 30, 2006 were 15.0% and 2.2 x, respectively. Cash flow is improving as a result of higher provider-of-last-resort rates, participation as a generation supplier in auction markets, and from the transition to market-based rates in the deregulated sector of its business, but will be also tempered by higher coal costs. Lingering operational issues remain. A $100 million rate case decision pending in West Virginia is important to credit quality. A significant increase in environmental compliance costs at the Fort Martin and Hatsfield Ferry plants will slow deleveraging, but is not expected to pose an immediate challenge. — Aneesh Prabhu

Allegheny Energy Supply Co. LLC (BB+/Positive/--)

See Allegheny Energy Inc. — Aneesh Prabhu

ALLETE Inc. (BBB+/Stable/A-2)

Cash flow protection metrics have rebounded after dipping considerably in 2005 due to a one-time $77 million cash payment (including closing costs), which was related to the transfer of the Kendall County power contract in the first half of 2005. The power purchase agreement's (PPA) termination was favorable for credit quality as it reduced the company's after-tax losses by $8 million annually. ALLETE's merchant generation assets are now limited to its 200 MW Taconite Harbor facility, which is fully contracted through 2010. Fully adjusted (including pensions) FFO to debt for the 12 months ended September 2006 was about 27%. Adjusted FFO for the 12 months ended September 2006 excludes nonrecurring Kendall-related federal tax benefits of $24.3 million (due to a capital loss carryback refund) which were realized in the third quarter of 2006. — Jeanny Silva

Alliant Energy Corp. (BBB+/Stable/A-2)

Sale of Alliant Energy New Zealand Ltd. is expected to close by the end of the year. Once this transaction is complete, Alliant Energy's international activates will be confined to holdings in a handful of Chinese power plants and a small Mexican resort development. With the sale of most of its nonregulated and international assets, the company is better positioned to focus on rate cases and generation investments at its core U.S. utility subsidiaries. WP&L is seeking $105 million electric and gas rate increases (effective in 2007) in Wisconsin. At nearly 18%, fully adjusted FFO to debt (including pension adjustments) is adequate given the current level of business risk. — Jeanny Silva

Alliant Energy Resources Inc. (BBB+/Stable/A-2)

See Alliant Energy Corp. — Jeanny Silva

Ameren Corp. (BBB/Watch Neg/A-2)

The immediate credit concern for Ameren is possible legislation mandating an electric rate freeze extension beyond year-end, which would quickly lead to the insolvency of the company's Illinois utility subsidiaries, or an unfavorable mandatory rate deferral plan. Although Illinois legislators failed to pass rate freeze legislation in this fall's veto session, Standard & Poor's remains concerned that rate freeze legislation could resurface in the January veto session. The ratings effect of any mandatory rate phase-in plan will ultimately depend on the magnitude of implied deferrals and the legislation's provisions for securitization. Meanwhile, the September 2006 supply auction rates are scheduled to go into effect Jan. 2, 2007. — Barbara Eiseman

AmerenEnergy Generating Co. (BBB/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

American Electric Power Co. Inc. (BBB/Stable/A-2)

American Electric Power Co. Inc. (AEP) faces an almost constant cycle of regulatory proceedings in one or more of the 11 states in which it operates, as well as at the federal level. The Texas Public Utilities Commission's decision to cut stranded-cost recovery was a credit disappointment. The mostly coal-burning company will be spending a lot of money on environmental compliance, a massive undertaking that heightens operating risk and regulatory risk, and threatens — Todd Shipman

AEP's generation cost advantage.

American States Water Co. (A-/Stable/--)

Net income for the nine months ended Sept. 30, 2006 was $ 22.8 million, a 7% decrease for the same period in 2005. Earnings remained strong but decreased slightly due primarily to the net effect of a number of one time adjustments for various items. Cash flow protection measures are adequate, with FFO coverage of interest of about 3.8x. Liquidity is acceptable with $2.7 million in cash and almost $49 million available under a $85 million revolver. — *Michael Scholder*

American Transmission Co. (A+/Stable/A-1)

As ATC continues its extensive transmission building program, we expect that capital spending will not substantially weaken the company's stable financial measures, which as of Sept. 30, 2006, were very strong for the rating with FFO interest coverage of 4.3x, FFO to total debt of 18.7%, and total debt to total capital of 51.3%. The company's financial measures are expected to remain solid in the intermediate term in part due to constructive FERC regulation and reliable operations. — Gerrit Jepsen

American Water Capital Corp. (A-/Watch Neg/--)

See American Water Works Co. — Kenneth L. Farer

American Water Works Co. Inc. (A-/Watch Neg/A-2)

Historical earnings and margins are stable, supported by healthy markets and regulatory recovery, although recovery can lag actual spending levels. For the past five years, FFO to total debt has been about 10% and FFO interest coverage was in the 1.5x to 2.5x area. These cash flow metrics are somewhat weak for the 'A-' rating. We will reassess the financial risk profile when additional information is available concerning the company's post-IPO business plan and capital structure — Kenneth L. Farer

Appalachian Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Aqua Pennsylvania Inc. (A+/Stable/--)

Parent Aqua America Inc. continues to acquire water and wastewater systems throughout its service territory to maintain its above-average growth rate, and has completed about 17 acquisitions to date in 2006. The company uses a mix of debt and equity to fund its cash flow shortfall in order to maintain debt leverage within the rating category. Consolidated financial performance is expected to remain strong, with adjusted funds from operations to total debt greater than 18% and adjusted FFO interest coverage above 4x. In addition, more than half of the rate increases projected by the company for 2007 have been approved to date, and could generate substantial cash flows next year. — Plana Lee

Aquarion Co. (A/Watch Neg/--)

Aquarion's pending sale to Macquarie Bank Ltd. has been approved by regulators in Connecticut and New Hampshire, and awaits approval in New York. Macquarie's intended business strategy for Aquarion and a credit-conducive financing structure could support Aquarion's current rating level. The company's FFO interest coverage was 3.7x for the 12 months ended June 2006. Completion of the regulatory process is expected to occur in early 2007. — Plana Lee

Aquarion Water Co. of Connecticut (A/Watch Neg/--)

See Aquarion Co. — Plana Lee

Aquila Inc. (B/Watch Pos/B-3)

Aquila has reduced business risk significantly, achieved material debt reduction, and lowered its ongoing working capital requirements. Aquila's rating will likely be raised to 'B+' once the company sells its Kansas electric utility ($250 million) and completes its debt reduction plan. Of particular interest will be how Aquila plans to address its 14.875% $500 million long-term debt. Improvements in cash flow protection will hinge on addressing this issue, eliminating operating costs related to utility divisions that have been sold or will be sold, and obtaining favorable regulatory decisions regarding capital recovery and fuel adjustment. Adjusted debt to capital was about 61% (including pension adjustments) as of September 2006. The company's decision on Dec. 5, 2006 to cancel its plans to acquire the Aries Power Plant from Calpine Corp for $158.5 million makes additional funds available for debt reduction. — *Jeanny Silva*

Arizona Public Service Co. (BBB-/Stable/A-3)

See Pinnacle West Capital Corp. — Anne Selting

Atlanta Gas Light Co. (A-/Negative/--)

See AGL Resources Inc. — Michael Messer

Atlantic City Electric Co. (BBB/Stable/A-2)

See PEPCO Holdings Inc. — Gerrit Jepsen

Atmos Energy Corp. (BBB/Stable/A-2)

For the fiscal year ended Sept. 30 2006, funds from operations (FFO) to debt was 21.6% and FFO interest coverage was 3.6x, consistent with the rating category, but the debt to capital ratio at 68% was weak. Performance was primarily driven by strong results from nonutility gas marketing operations, which offset effects of warmer-than-normal weather. — Chinelo Chidozie

Avista Corp. (BB+/Stable/B-1)

An electric fuel and purchased power recovery mechanism in Washington that has had a sizable $9 million deadband before any sharing is applied has contributed to deferral balances that stood at $112 million as of Sept. 30, 2006. Although a recent favorable revision to lower the deadband to $4 million should assist future utility cash flows, funds from operations to total debt in recent years has been weak for the rating, as has leverage. The ability of the company to improve consolidated metrics will continue to be significantly driven by hydro conditions as well as by the performance of Avista Energy, the company's trading and marketing company, whose earnings and cash flows are volatile. — Anne Selting

Baltimore Gas & Electric Co. (BBB+/Negative/A-2)

See Constellation Energy Group Inc. — Aneesh Prabhu

Baton Rouge Water Works Co. (The) (AA/Stable/--)

Capital expenditures should remain elevated in 2006 and 2007 to meet supply needs in the high-growth Ascension Parrish area and to serve the increase in customers who moved from New Orleans after the 2005 hurricanes. However, the one-time nature of these construction costs and the company's ability to cover most of them internally should obviate any negative effects. Financial performance should remain robust, led by the company's healthy free operating cash flow, its adjusted FFO to total debt ratio of greater than 30%, and its adjusted FFO interest coverage of greater than 5.5x. — Michael Scholder

Bay State Gas Co. (BBB/Stable/--)

See NiSource Inc. — Barbara Eiseman

Black Hills Corp. (BBB-/Negative/--)

Adjusted FFO to total debt (excluding pensions) was 24% during the 12 months ended September 2006, up from about 18% during in the previous period due largely to improved operations at regulated and nonregulated power plants and higher energy marketing margins. Lack of operational difficulties at the company's unregulated generation segment and the recent rate settlement with the South Dakota Public Utilities Commission enhance credit quality. The settlement calls for various adjustment mechanisms that protect the company from unforeseen changes in the cost of fuel, purchased power, and transmission. Black Hills' oil and gas segment reported additional production issues due to an outage and regulatory delays in bringing new wells on-line which will cause a 10% decline in the growth target for oil and gas production in 2006. — Jeanny Silva

Black Hills Power Inc. (BBB-/Negative/--)

See Black Hills Corp. — Jeanny Silva

Boston Edison Co. (A+/Stable/A-1)

See NSTAR — Kenneth L. Farer

Boston Gas Co. (A/Watch Neg/--)

See KeySpan Corp. — Kenneth L. Farer

California Water Service Co. (A+/Stable/--)

Financial results remain healthy despite a modest decline in comparable year to date results due to higher wholesale water prices and increased costs associated with employee health and welfare plans. Cash flow protection measures were adequate, with FFO coverage of interest of about .4x. As of Sept. 30, 2006, liquidity was satisfactory, with $4 million in cash and a $45 million credit line at the operating company level plus $10 million at the parent, with a combined total undrawn capacity of $43 million.	Michael Scholder
Calpine Construction Finance Co. L.P. (CCC-/Negative/--)	
The 'CCC-' rating continues to reflect the possibility that Calpine Construction (CCFC) could be consolidated into the Calpine bankruptcy, although the likelihood has decreased in the months since the Calpine bankruptcy. Calpine Energy Services continues to perform in accordance with the terms of its gas sale and power purchase agreement with CCFC.	Swami Venkataraman
Calpine Corp. (D/--/--)	
The company remains in bankruptcy and has not yet filed a plan of reorganization.	Swami Venkataraman
Calpine Generating Co. LLC (D/--/--)	
The company remains in bankruptcy and has not yet filed a plan of reorganization.	Swami Venkataraman
Cambridge Electric Light Co. (A+/Stable/--)	
See NSTAR	Kenneth L. Farer
Carolina Power & Light Co d/b/a Progress Energy Carolinas Inc. (BBB/Stable/A-2)	
See Progress Energy Inc.	Jodi Hecht
Cascade Natural Gas Corp. (BBB+/Stable/--)	
On Feb. 15, 2006, the company filed with the Washington Utilities and Transportation Commission for its first base rate increase in 10 years. In addition, the company requested that the commission approve a "decoupling" mechanism to address the impact of retail sales volatility on fixed cost recovery. Exposure to gas cost volatility is mitigated by purchased gas cost adjustment mechanisms in both Washington and Oregon, although regulatory lag issues can arise due to the build-up of deferred gas costs between adjustment dates. Cash flow coverage remains strong, while debt leverage has declined to favorable levels. The company is expected to be acquired by MDU Resources Inc.	Leo Carrillo
CenterPoint Energy Houston Electric LLC (BBB/Stable/NR)	
See CenterPoint Energy Inc.	Dimitri Nikas
CenterPoint Energy Inc. (BBB/Stable/--)	
While the settlement agreement with IRS regarding the tax treatment of the ZEN securities and the rate case settlement with the Public Utility Commission of Texas reduces the tax and regulatory uncertainty, the company is still working on resolving the issue of stranded cost true-up for the Houston transmission and distribution operations and working through some regulatory challenges in Minnesota to recover previously incurred gas costs. CenterPoint continues to be highly leveraged and its financial risk profile may be affected by how it chooses to finance CERC's large capital expansion needs. CenterPoint mitigates the risk of the new projects in part by signing long-term agreements with anchor shippers.	Dimitri Nikas
CenterPoint Energy Resources Corp. (BBB/Stable/--)	
See CenterPoint Energy Inc.	Dimitri Nikas
Central Hudson Gas & Electric Corp. (A/Stable/--)	
Parent CH Energy's credit ratios are somewhat weak for the current rating with FFO interest coverage of about 5x, FFO to debt of 17%, and debt to capital over 50%. Central Hudson's three-year rate agreement was approved in July 2006 and includes a $54 million increase in electric revenues and $14 million increase in gas revenues, although the authorized ROE of 9.6% is materially lower than the previous 10.3%. The increased revenues are required to cover increased operating costs, particularly pension and other postemployment benefits, and infrastructure improvements. CH Energy has invested $25 million for various energy related assets as part of its plan to build a portfolio with the proceeds from the sale of its generating facilities in 2001.	Kenneth L. Farer
Central Illinois Light Co. (BBB-/Watch Neg/--)	

See Ameren Corp.	Barbara Eiseman
Central Illinois Public Service Co. (BBB-/Watch Neg/--)	
See Ameren Corp.	Barbara Eiseman
Central Maine Power Co. (BBB+/Negative/--)	
See Energy East Corp.	Ralph DeCesare
Central Vermont Public Service Corp. (BB+/Stable/--)	
Central Vermont's credit measures remain weak, with FFO interest coverage below 2x, FFO to debt below 10%, and debt to capital of over 70%. The company continues to implement its financial restoration plan and received a 4.07% rate increase, effective Jan. 1, 2007. Management has stated that its rate cases through 2012 will mainly address alternative regulation and rate increases to offset the inflationary effects of labor, benefits, and other non-energy price costs. However, to generate investment-grade financial measures, substantive rate relief is required, given the company's material off-balance-sheet debt and somewhat nondiscretionary investments related to transmission system improvements.	Kenneth L. Farer
CILCORP Inc. (BBB-/Watch Neg/--)	
See Ameren Corp.	Barbara Eiseman
Cinergy Corp. (BBB/Positive/A-2)	
See Duke Energy Corp.	Dimitri Nikas
Cleco Corp. (BBB/Negative/--)	
Cleco's credit profile is dominated by the construction of the $1 billion Rodemacher 3,600 MW generation facility and by the residual aspects of the company's merchant generation growth strategy. Cleco issued $158 million of equity to finance part of Rodemacher. An interim regulatory rate plan allows recovery of 75% of the financing costs in rates. The plant will address Cleco Power's shortfall in owned generation, currently filled through short-term power purchases, and will provide some diversification away from natural gas.	Dimitri Nikas
Cleco Power LLC (BBB/Negative/--)	
See Cleco Corp.	Dimitri Nikas
Cleveland Electric Illuminating Co. (BBB/Stable/--)	
See FirstEnergy Corp.	Todd Shipman
CMS Energy Corp. (BB/Stable/B-1)	
Excess leverage from poor legacy investments limits ratings upside potential. Utilizing a regulatory "out" provision in the utility's power purchase arrangement with MCV in 2007 will likely require sourcing replacement power. The sale of the Palisades nuclear plant will lower business risk. Adjusted debt to capital of greater than 70% and FFO to total debt of 10% remain stretched for the rating. The company has adequate bank lines available, but liquidity remains an issue. Expiring rate caps at Consumers will support financial performance.	Ralph DeCesare
Colonial Gas Co. (A/Watch Neg/--)	
See KeySpan Corp.	Kenneth L. Farer
Columbus Southern Power Co. (BBB/Stable/--)	
See American Electric Power Co. Inc.	Todd Shipman
Commonwealth Edison Co. (BBB-/Watch Neg/A-2)	
The CreditWatch listing reflects the potential for Illinois to extend the company's current rate freeze for another three years. While Illinois legislators have failed twice to pass rate-freeze legislation, Standard & Poor's remains concerned	Jeanny Silva

that such legislation could resurface in the coming months and that Senate opposition could erode once customers begin to feel the impact of higher rates. If a rate freeze passes, we would lower Commonwealth Edison's ratings to the 'B' category. Absent a rate freeze, an immediate downgrade of the company is unlikely.

Commonwealth Electric Co. (A+/Stable/–)

See NSTAR — Kenneth L. Farer

Connecticut Light & Power Co. (BBB/Stable/--)

See Northeast Utilities — Ralph DeCesare

Connecticut Natural Gas Corp. (BBB+/Negative/--)

See Energy East Corp. — Ralph DeCesare

Connecticut Water Co. (The) (A/Stable/--)

See Connecticut Water Service Inc. — Plana Lee

Connecticut Water Service Inc. (A/Stable/–)

Connecticut Water Service Inc.'s earnings should be lower in 2006 due to the sale of the company's Barnstable water operations in May 2005 and increase in operating costs. A decision for the 30% rate increase filed in July 2006 is expected by January 2007. Adjusted funds from operations to total debt of 13.5% and adjusted FFO interest coverage of 3.2x are weak for the current rating. The company may be pressured to maintain its modest financial risk profile without proper rate relief. — Plana Lee

Consolidated Edison Co. of New York Inc. (A/Negative/A-1)

See Consolidated Edison Inc. — Kenneth L. Farer

Consolidated Edison Inc. (A/Negative/A-1)

Financial ratios have deteriorated in 2006 due to a regulatory lag associated with the company's capital program, higher levels of debt, and spending related to the outages incurred in the summer of 2006. We expect financial measures to improve, given subsidiary Consolidated Edison Co. of New York's rate increase of $220 million in 2007. Implicit in the current rating is the expectation that rate increases through 2008 will be sufficient to improve FFO to debt to 16% and FFO interest above 3.5x. However, a downgrade could occur if these ratios do not appear achievable, which could occur if debt levels increase significantly to fund higher-than-expected outage-related costs, if the 2008 rate agreement is significantly lower than anticipated, or Con Edison undertakes a higher-risk strategy or increases its leverage. — Kenneth L. Farer

Consolidated Natural Gas Co. (BBB/Positive/A-2)

See Dominion Resources Inc. — Aneesh Prabhu

Constellation Energy Group Inc. (BBB+/Negative/A-2)

A new state law requires subsidiary Baltimore Gas & Electric Co. to defer recovery of power costs, but at the same time allows immediate relief through securitization. A troubling precedent of legislative intervention could still affect the utility's credit quality if future supply cost increases are also controlled. Repricing of Constellation's power generation fleet should increase cash flow on a consolidated basis. Consolidated financial measures of funds from operations (FFO) to debt at about 18% and FFO to interest of about 3.7x after adjusting for debt-like obligations are weak, but the use of proceeds from the proposed sale of 3,150 MW of gas-fired assets for debt reduction will benefit balance-sheet strength. — Aneesh Prabhu

Consumers Energy Co. (BB/Stable/B-1)

See CMS Energy Corp. — Ralph DeCesare

Coral Energy Holding L.P. *(A-/Stable/-)*

Coral's rating continues to reflect the rating of parent Shell Oil, and Coral's importance to Shell Oil for marketing Shell Oil's products into North American markets. Coral continues to be exposed to negative margin tolling contracts in North — Terry Pratt

American markets, but losses are more than offset by positive margins in the core business.

Dayton Power & Light Co. (BB+/Positive/--)

See DPL Inc. — Todd Shipman

Delmarva Power & Light Co. (BBB/Stable/A-2)

See PEPCO Holdings Inc. — Gerrit Jepsen

Detroit Edison Co. (BBB/Stable/A-2)

See DTE Energy Co. — Ralph DeCesare

Dominion Resources Inc. (BBB/Positive/A-2)

Lower gas prices and mild weather have mitigated fuel-related expenses, which are unrecoverable above levels established by a frozen fuel factor through mid-2007. The company decided to sell most of its exploration and production assets, especially since changes in Virginia legislation obviate the need for exploration and production to act as a natural hedge for utility fuel costs. Proceeds from the sale will be first used to achieve targeted financial measures of above 4x FFO to interest, 20% FFO to debt, and about 50% debt to capital, which is credit supportive. The sale would also support an overall lower business risk. Liquidity concerns have receded with gas prices at a more sustainable level. — Aneesh Prabhu

DPL Inc. (BB+/Positive/--)

DPL recently hired a new CEO with utility industry experience, and expectations are that the business strategy will focus on the utility. The company has announced its intent to sell three gas peaking plants that have failed to generate positive returns; proceeds could be used to improve the financial profile by reducing debt. DPL's financial profile is slowly being restored, with FFO interest coverage for 2006 is expected to be 3.1x. — Todd Shipman

DTE Energy Co. (BBB/Stable/A-2)

DTE is considering selling various nonregulated assets, but has not made any commitments, nor expressed balance sheet targets. They have commenced a one million share buyback program prior in anticipation of receipt of asset sale proceeds. The tax-driven synfuels business has had another good year, but is expected to terminate shortly. Detroit Edison received some regulatory relief in the form of an uncollectibles tracker and an enhanced rate design that should enable it to compete more effectively for industrial and commercial customers. FFO to total debt of 17% is weak for the rating. — Ralph DeCesare

Duke Capital LLC (BBB/Positive/A-2)

See Duke Energy Corp. — Dimitri Nikas

Duke Energy Carolinas LLC (BBB/Positive/A-2)

See Duke Energy Corp. — Dimitri Nikas

Duke Energy Corp. (BBB/Positive/--)

Duke Energy's separation of its electric and natural gas operations are scheduled to occur Jan. 1, 2007. Standard & Poor's revised the outlook on Duke Capital (in essence the core of the new gas company) to positive to reflect the entity's potential for a ratings upgrade of up to two notches. At the same time, the ratings on the remaining electric company were affirmed with a positive outlook to reflect the likelihood for a higher rating as well. Duke Energy is mitigating business risk at the regulated operations, most recently completing the sale of Cinergy's trading and marketing operations. — Dimitri Nikas

Duke Energy Indiana Inc. (BBB/Positive/A-2)

See Duke Energy Corp. — Dimitri Nikas

Duke Energy Kentucky Inc. (BBB/Positive/--)

See Duke Energy Corp. — Dimitri Nikas

Duke Energy Ohio Inc. (BBB/Positive/A-2)

See Duke Energy Corp. — Dimitri Nikas

Duke Energy Trading and Marketing LLC (BBB-/Stable/--)

See Duke Energy Corp. — Dimitri Nikas

Duquesne Light Co. (BBB/Watch Neg/--)

See Duquesne Light Holdings Inc. — Gerrit Jepsen

Duquesne Light Holdings Inc. (BBB/Watch Neg/--)

Credit quality can be affected by multiple pending issues. Distribution and transmission rate proceedings could result in strengthened cash flow measures, particularly during the company's currently high capital spending phase. Moreover, rate increases will help bolster cash flow measures as other businesses such as synthetic fuel operations are phased out. Also, the pending acquisition by Macquarie Infrastructure Partners and Diversified Utility and Energy Trusts for $3.15 billion could affect credit quality because of the significant amount of debt financing being proposed. Increasing consolidated debt by one-third will weaken financial measures after the acquisition closes. — Gerrit Jepsen

Dynegy Holdings Inc. (B/Watch Dev/--)

See Dynegy Inc. — Swami Venkataraman

Dynegy Inc. (B/Watch Dev/B-2)

The ratings on Dynegy and its subsidiaries are on CreditWatch with developing implications following the acquisition of LS Power's assets that was announced on Sept. 15, 2005. Since the purchase is financed primarily with Dynegy common stock, we expect to affirm all our ratings on Dynegy and Dynegy Holdings if the transaction is consummated as currently expected. We expect Dynegy to operate all assets as one portfolio, although project financings at the LS Power entities are expected to be largely untouched. The acquisition improves the geographic and dispatch diversity of the portfolio and provides for near term cash flow certainty since LS Power's fleet is substantially contracted. — Swami Venkataraman

E.ON U.S. LLC (BBB+/Stable/--)

E.ON U.S.'s two utilities in Kentucky are good performers, with low costs, a reasonable regulatory environment, and high customer satisfaction ratings. Capital spending on environmental compliance upgrades has been mostly completed. Parent E.ON AG continues to back up its support for E.ON U.S., which is important for ratings stability. — Todd Shipman

Edison International (BBB-/Stable/--)

Ratings stability is expected in the near term following a recent rating downgrade. The rating action came in response to revised strategic policies that allow capital infusions to be made into unregulated subsidiaries if needed to support growth initiatives. As compared with 2005, the company exhibited continued improvement in fully adjusted FFO interest coverage which exceeded 3.0x for the adjusted the 12 months ended Sept. 30, 2006. For the same period, FFO to total debt strengthened to 18%. — David Bodek

Edison Mission Energy (BB-/Stable/--)

The recent ratings upgrade reflects management's revised strategic policies that allow capital infusions to be made from Edison Mission Energy's ultimate parent, Edison International, into its unregulated subsidiaries if needed to support growth opportunities and if in the best interest of shareholders. Adjusted financial metrics for the 12 months ended Sept. 30, 2006, remained largely in line with metrics for the fiscal year ended Dec. 31, 2006, including FFO interest coverage of about 2.1x and a slight reduced FFO debt coverage of about 8.5x. Following the upgrade, the rating outlook was restored to stable from positive to reflect the financial pressures that will likely result from capital expenditures needed to implement emissions reductions. — David Bodek

Edison Mission Marketing and Trading (BB-/Stable/--)

Edison Mission Marketing and Trading is rated on a consolidated basis with Edison Mission Energy. Trading and marketing activities are largely restricted to hedging activities for coal-fired generation. — David Bodek

El Paso Electric Co. (BBB/Stable/--)

Cash flow trends remain strong, and issues at the Palo Verde nuclear power station appear to have been resolved. Palo Verde unit 2 returned to full operations after a planned refueling outage in November. Funds from operations (FFO) interest coverage and FFO to debt ratio was a strong 6x and 25%, respectively, for the 12-month period ended September 2006. Strong cash flow was driven by a combination of retail sales growth, off-system sales, and recovery of previously deferred fuel expenses. — Chinelo Chidozie

Empire District Electric Co. (BBB-/Stable/A-3)

Integration of the acquired gas utility, now Empire Gas, is a key influence on the company's financial performance. Empire's $30 million electric rate case pending before the Missouri Public Service Commission should be completed shortly. The outcome is important to Empire's creditworthiness given the lack of a permanent energy-cost recovery mechanism and heavy capital spending program. Financial measures have been mixed for the rating, and are expected to remain so over the near term.	Gerrit Jepsen
Energen Corp. (BBB+/Stable/--)	
Energen continues to benefit from higher oil and gas prices, as exploration and production operations continue to boost consolidated cash flows. The announced joint venture with CHK to develop Alabama Shale should assuage concerns about escalating capital expenditures at the E&P unit. The rating is stable due to the strength of the Alabama Gas utility business. FFO to total adjusted debt improved to 54% for the 12 months ending Sept. 30, 2006.	Charles Laporta
Energy East Corp. (BBB+/Stable/A-2)	
Financial parameters are weak due to an unfavorable regulatory ruling at largest subsidiary New York State Electric & Gas Corp. (NYSEG). NYSEG requested a $58 million rate hike (11% ROE) but received a $36 million rate cut (9.55% ROE) ruling. The ruling also requires the utility to utilize a variable rate supply option, which can make earnings more volatile. Formerly solid funds from operations (FFO) to interest coverage of 3.1x and FFO to debt of 16.4% are likely to weaken in 2007.	Ralph DeCesare
Enogex Inc. (BBB+/Stable/--)	
See OGE Energy Corp.	Jeanny Silva
Entergy Arkansas Inc. (BBB/Negative/--)	
See Entergy Corp.	Dimitri Nikas
Entergy Corp. (BBB/Negative/--)	
Entergy continues to recover storm costs throughout its jurisdictions. All subsidiaries are authorized to create storm reserve accounts. Entergy's ongoing challenges include the dispute surrounding the system agreement for Arkansas and the potential for separation of Entergy Gulf States into a Texas and Louisiana based companies. The company's financial profile remains robust with adequate credit protection measures for the 12 months ended Sept. 30, 2006.	Dimitri Nikas
Entergy Gulf States Inc. (BBB/Negative/--)	
See Entergy Corp.	Dimitri Nikas
Entergy Louisiana LLC (BBB/Negative/--)	
See Entergy Corp.	Dimitri Nikas
Entergy Mississippi Inc. (BBB/Negative/--)	
See Entergy Corp.	Dimitri Nikas
Entergy New Orleans Inc. (D/--/--)	
See Entergy Corp.	Dimitri Nikas
Equitable Resources Inc. (A-/Watch Neg/A-2)	
The total purchase price of Dominion Resources' natural gas distribution and midstream businesses is expected to be about $970 million, and it is not certain what mix of debt, equity and/or asset sales management will use to fund the purchase. While the lower business risk distribution business will make up about one-quarter of operating income after the acquisition (up from about 13% prior), the uncertainty about the ultimate capital structure, as well as the planned formation of a holding company, keep the ratings under review.	Ralph DeCesare
Exelon Corp. (BBB+/Watch Neg/A-2)	
The ratings on Exelon, Exelon Generation (ExGen), and PECO Energy remain on CreditWatch with negative implications due to the potential for legislators in Illinois to extend subsidiary Commonwealth Edison's (ComEd) current rate freeze for another three years. Despite having taken steps to insulate itself from a bankruptcy filing at ComEd, if rate freeze legislation is signed into law, the ratings on Exelon and ExGen would likely decline due to heightened counterparty credit risk at ExGen (ComEd and Ameren Corp.'s utilities will be customers of ExGen after 2006) and the potential for permanent loss of dividend income from ComEd to Exelon. Fully adjusted FFO to debt (22%) for the 12 month period	Jeanny Silva

ending September 2006 is moderate to weak for the rating. Absent a rate freeze extension, consolidated financial metrics should improve with additional (and higher margin) market.

Exelon Generation Co. LLC (BBB+/Watch Neg/A-2)

See Exelon Corp. — Jeanny Silva

FirstEnergy Corp. (BBB/Stable/--)

The company's rate certainty plan in Ohio will lower cash flow in the near term, but is viewed as credit neutral, as it preserves the recovery of increased fuel costs after 2008. The company's operating performance has been satisfactory, but doubts remain on the sustainability of nuclear operations. Rate cases in Pennsylvania and the post-2008 market structure in Ohio are other risks. Climbing maintenance expenditures will cut into free cash flow in 2006. Financial metrics and liquidity have improved markedly, as substantial debt was paid down in 2005. A share-repurchase program will bruise credit metrics, but they will remain consistent with ratings. — Todd Shipman

Florida Power & Light Co. (A/Stable/A-1)

See FPL Group Inc. — Jodi Hecht

Florida Power Corp d/b/a Progress Energy Florida Inc. (BBB/Stable/A-2)

See Progress Energy Inc. — Jodi Hecht

Florida Progress Corp. (BBB/Stable/A-2)

See Progress Energy Inc. — Jodi Hecht

FPL Group Capital Inc. (A/Stable/A-1)

See FPL Group Inc. — Jodi Hecht

FPL Group Inc. (A/Stable/--)

FPL Group's consolidated financial performance for the 12 months ended Sept. 30, 2006 reflected improved cash flow from the collection of the fuel surcharge at the utility. FFO to interest coverage has improved to over 4x compared to 2.7x for the twelve months trailing Sept. 30, 2005 and FFO to average debt grew to over 19.5x as of Sept. 30, 2006 compared with over 13.5% in the previous year. The debt to capital ratio, which was over 55% at Sept. 30, 2006, is expected to decline when the utility uses the proceeds from the storm securitization to reduce consolidated debt. — Jodi Hecht

Georgia Power Co. (A/Stable/A-1)

See Southern Co. — Terry Pratt

Golden State Water Co. (A-/Stable/--)

See American States Water Co. — Michael Scholder

Great Plains Energy Inc. (BBB/Stable/--)

Fully adjusted (including pensions) cash flow protection measures remain adequate for the rating, with adjusted FFO to debt at about 22% for the twelve months ending Sept 2006. At 57% adjusted leverage is moderate. Although Kansas City Power & Light's (KCPL) capital requirements are high, access to a regulatory accelerated amortization mechanism is a mitigating factor. In December 2006, KCP&L received a favorable regulatory order in Missouri approving roughly $51 million increase in annual revenues, reflecting an ROE of 11.25% and an equity ratio of 53.7%. About $22 million of the increase reflects additional amortization to help maintain cash flow levels. In Kansas, KCPL recently agreed to a settlement equal to $29 million. — Jeanny Silva

Green Mountain Power Corp. (BBB/Watch Pos/--)

The ratings on electric power utility Green Mountain Power Corp. remain on CreditWatch with positive implications, following the acquisition announcement on June 22, 2006, by Northern New England Energy Corp., a subsidiary of Gaz Metro Inc. (A-/Negative/--). The company has negotiated a 9.6% rate increase for 2007 to offset current high power and transmission costs. The Vermont Public Service Board must still approve the utility's rate case and alternative regulatory plan. Over the intermediate term, Green Mountain Power will require additional rate relief to maintain financial measures appropriate for the current ratings, given the anticipated increases in power costs with the expiration of its power supply hedge. — Kenneth L. Farer

Gulf Power Co. (A/Stable/--)

See Southern Co. — Terry Pratt

Hawaiian Electric Co. Inc. (BBB+/Negative/A-2)

See Hawaiian Electric Industries Inc. — Barbara Eiseman

Hawaiian Electric Industries Inc. (BBB/Negative/A-2)

Third quarter results were down mainly due to lower investment gains. Higher operations and maintenance expenses largely offset revenues from interim rate relief granted in the fall of 2005. Electric sales were essentially flat owing to cooler, less humid weather and conservation. The bank subsidiary's earnings continued to be challenged by margin compression and rising interest costs, causing lower third quarter bank earnings. Accelerating construction expenditures will necessitate an increased reliance on outside capital. A final rate order regarding subsidiary Hawaiian Electric's pending rate case is crucial to help lift financial measures to more appropriate levels and eliminate the rating's negative outlook. Also of some concern is Hawaii's Act 162, a new law which appears to confirm the public utility commission's ability to authorize the utility's fuel adjustment clause. A material change to this mechanism would harm the company's financial profile and detract from its satisfactory business position. — Barbara Eiseman

IDACORP Inc. (BBB+/Negative/A-2)

With the drought's end and the rebounding power sales revenues for its primary subsidiary, Idaho Power, financial ratios for IDACORP are expected to continue to improve to levels commensurate with its 'BBB+' rating. Operating income increased by almost 30% through the first three quarters of 2006. Leverage moderated as total debt as well. Cash flow protection measures are adequate, with FFO coverage of interest of about 4.0x. Liquidity is satisfactory as well. — Michael Scholder

Idaho Power Co. (BBB+/Negative/A-2)

See IDACORP Inc. — Michael Scholder

Illinois Power Co. (BBB-/Watch Neg/--)

See Ameren Corp. — Barbara Eiseman

Indiana Gas Co. Inc. (A-/Stable/--)

See Vectren Corp. — Gerrit Jepsen

Indiana Michigan Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Indianapolis Power & Light Co. (BB+/Positive/--)

See IPALCO Enterprises Inc. — Barbara Eiseman

International Transmission Co. (BBB/Positive/--)

See ITC Holdings Corp. — Gerrit Jepsen

Interstate Power & Light Co. (BBB+/Stable/A-2)

See Alliant Energy Corp. — Jeanny Silva

IPALCO Enterprises Inc. (BB+/Positive/--)

The outlook on IPALCO was revised in mid-2006 to positive from stable as we expect certain key financial metrics to strengthen over the next couple of years due to somewhat lower-than-expected environmental-related capital outlays, supportive ratemaking treatment for such expenditures, reduced external funding needs, and cost controls. Currently strong internal funding of the company's construction program is expected to slip below 75% for 2006 when environmental-related spending peaks, and rebound to over 100% in 2007. Meanwhile, consolidated adjusted total debt to capital will hover around an exceptionally high 108% to 110%. — Barbara Eiseman

ITC Holdings Corp. (BBB/Positive/--)

The integration of recently acquired Michigan Electric Transmission Co. (METC) will be reviewed over the next several months along with any changes in the methodology used to set rates at METC. Cash flow measures are expected to decline to levels more consistent with benchmarks, while leverage is expected to remain about 70%. — Gerrit Jepsen

Jersey Central Power & Light Co. (BBB/Stable/--)

See FirstEnergy Corp. — *Todd Shipman*

Kansas City Power & Light Co. (BBB/Stable/A-2)

See Great Plains Energy Inc. — Jeanny Silva

Kansas Gas & Electric Co. (BB+/Positive/--)

See Westar Energy Inc. — Barbara Eiseman

Kentucky Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Kentucky Utilities Co. (BBB+/Stable/A-2)

See E.ON US — Todd Shipman

KeySpan Corp. (A/Watch Neg/A-1)

Ratings on KeySpan Corp. remain on CreditWatch with negative implications, given the pending sale of the company to National Grid PLC (A/Watch Neg/A-1) for $7.3 billion (£4.2 billion) plus assumed debt of $4.5 billion (£2.6 billion). We anticipate resolving the CreditWatch listing and lowering the ratings on KeySpan and its subsidiaries by one notch when the acquisition receives regulatory approval and becomes unconditional. This is expected in mid-2007, following approval from New York and New Hampshire state public utility regulatory commissions. Despite the acquisition, we expect additional improvement in KeySpan's cash flow measures and reduced leverage over the intermediate term. — Kenneth L. Farer

KeySpan Energy Delivery Long Island (A+/Watch Neg/--)

See KeySpan Corp. — Kenneth L. Farer

KeySpan Energy Delivery New York (A+/Watch Neg/--)

See KeySpan Corp. — Kenneth L. Farer

KeySpan Generation LLC (A/Watch Neg/--)

See KeySpan Corp. — Kenneth L. Farer

Kinder Morgan Inc. (BBB/Watch Neg/A-2)

The implementation of a Michigan Public Service Commission-authorized transition charge has helped to slow sales losses from the customer choice program in the first quarter of 2006. However, the commission is considering a rate decrease that could erode the company's financial profile below a level consistent with current ratings. The stable outlook on DTE Energy Co. is based in part in advancing a constructive regulatory agenda. In addition, synthetic fuel operations were expected to generate about one-third of total cash flow in 2006, but high oil prices could cut into that forecast. — Todd Shipman

Laclede Gas Co. (A/Stable/A-1)

See Laclede Group Inc. — Barbara Eiseman

Laclede Group Inc. (The) (A/Stable/--)

Funds from operations (FFO) to debt of below 18% and total debt to capital of above 60% are somewhat weak for the ratings. Weather-mitigation rate design, a gas supply incentive plan, a dividend reinvestment plan, and possible — Barbara Eiseman

increased profits from the company's unregulated ventures should modestly strengthen the company's financial condition. Laclede's recent purchase of Reliant Services LLC's Indiana assets was relatively small and funded with cash on hand.

Louisville Gas & Electric Co. (BBB+/Stable/A-2)

See E.ON US — Todd Shipman

Madison Gas & Electric Co. (AA-/Stable/A-1+)

Madison Gas & Electric's (MG&E) ratings were recently affirmed due to strong cash flow measures, all up from year-end 2005, and lower debt to capital. The company's construction program will continue to be monitored for any significant cost increases and the effect of the program on the utility's financial measures. We expect ongoing supportive regulation. — Gerrit Jepsen

Massachusetts Electric Co. (A/Watch Neg/A-1)

See National Grid USA — Kenneth L. Farer

Metropolitan Edison Co. (BBB/Stable/--)

See FirstEnergy Corp. — Todd Shipman

Michigan Consolidated Gas Co. (BBB/Stable/A-2)

See DTE Energy Co. — Ralph DeCesare

Michigan Electric Transmission Co. (BBB/Positive/--)

See ITC Holdings Corp. — Gerrit Jepsen

MidAmerican Energy Co. (A-/Stable/A-1)

MidAmerican Energy (MEC) continues its stable financial performance. FFO coverage of interest and debt for the 12 months ended Sept. 30, 2006 were 5.7x and 28%, respectively. Construction of the Council Bluffs coal plant is proceeding on schedule and should be completed in the summer of 2007. MEC has completed 360 MW of wind generation and received approval for another 545 MW in April 2006, which was partly financed through a first mortgage bond issue in October 2006. The company's rate settlement in Iowa extends through Dec. 31, 2011. The rate settlement does not incorporate a fuel adjustment clause, which may be problematic given increasing fuel costs, but this is mitigated by a largely stable coal-fired asset base and the ability to request a rate increase should the actual earned Iowa jurisdictional ROE falls below 10%. — Swami Venkataraman

MidAmerican Energy Holdings Co. (A-/Stable/--)

While MidAmerican Energy Holdings' (MEHC) credit metrics are improving, ratios are clearly weak for the 'A-' rating. The rating benefits from Berkshire Hathaway's support. For the 12 months ended Sept. 30, 2006, FFO to interest and debt stood at 3.3x and 10.9%, respectively. Debt to total capital had shown a substantial improvement from 77.8% as of Dec. 31, 2005 to 69.8% as of Sept 30, 2006, mainly reflecting the equity infusion for the acquisition of PacifiCorp. MEHC continues to look for investment opportunities, which would likely be funded in large part by equity from Berkshire Hathaway. — Swami Venkataraman

Middlesex Water Co. (A-/Stable/--)

Capital spending requirements continue to be high at subsidiaries Tidewater Utilities Inc. and Tidewater Environmental Services Inc. (TESI). In addition, regulatory treatment for new wastewater operations at TESI continues to be uncertain. Although, the company's FFO interest coverage remained stable at 3.6x for the 12 months ending September 2006, debt leverage was high at 58%.However, repayment of short-term debt from proceeds of the recently completed equity issuance is expected to support the company's credit measures. — Plana Lee

Midwest Independent System Operator Inc. (MISO) (A+/Stable/--)

Initially Louisville Gas & Electric's (LG&E) and Kentucky Utilities' withdrawals from the Midwest Independent Transmission System Operator Inc. (MISO) appeared to be unsupportive of credit quality, but the withdrawal did not weaken MISO's financial profile since the utilities paid an exit fee of about $33 million to MISO that may be used to cover the financial obligations that were related to the utilities' participation in MISO, including interest and principal payments on debt. However, any large exodus of higher-load members could introduce financial risk because remaining MISO's members would be required to pay for a greater share of costs for operations, financing, and capital expenditures. — Gerrit Jepsen

Mirant Americas Generating LLC (B+/Stable/--)

See Mirant Corp. — Terry Pratt

Mirant Corp. (B+/Stable/--)

Mirant completed a $1.23 billion stock repurchase in the third quarter of 2006 with cash, and expects to repurchase an *additional $100 million in stock, also from cash. Mirant recently reached an agreement to sell its Asian assets, which will* provide about $2.77 billion after paying down asset level debt. Mirant continues the bidding process for Caribbean and 3,504 MW of U.S. gas-fired power plant assets. Mirant expects to complete all asset sales by mid-2007. The credit effect of the sale of the assets, which provide about one-half of EBITDA, will depend on the company's capitalization plan and its liquidity strength to meet capital expenditures, supply working capital needs, and support trading operations. — Terry Pratt

Mirant Mid-Atlantic LLC (BB/watch Neg/--)

See Mirant Corp. — Terry Pratt

Mirant North America LLC (B+/Stable/--)

See Mirant Corp. — Terry Pratt

Mississippi Power Co. (A/Stable/A-1)

See Southern Co. — Terry Pratt

Monongahela Power Co. (BB+/Positive/--)

See Allegheny Energy Inc. — Aneesh Prabhu

MXEnergy Holdings Inc. (B/Stable/--)

The SESCo acquisition was successfully closed on Aug 1, 2006. Financial and operational performance for the fiscal year ended June 30, 2006 is in line with expectations. FFO coverage of interest and debt stood at 4.7x and 744%, respectively, while debt to capital was 2.6%, reflecting the virtual absence of debt prior to the SESCo acquisition. Management's focus over the next couple of years will be on integrating the SESCo acquisition and implementing formal internal controls for both accounting and risk management. Continuing to acquire customers at competitive rates is key. Funds from operations coverage of interest and debt is expected to be about 1.8x and 11.5% respectively in 2007, and improving over the next few years. — Swami Venkataraman

Narragansett Electric Co. (A/Watch Neg/A-1)

See National Grid USA — Kenneth L. Farer

National Fuel Gas Co. (BBB+/Stable/A-2)

National Fuel has submitted a rate case agreement with the Pennsylvania Public Utility Commission to increase annual revenues by $25.9 million. The in-service date for the company's planned expansion of its Empire State Pipeline has been pushed back a year to November 2008. Credit metrics continue to improve, but may prove volatile due to weak assets in the E&P unit, which have resulted in continuing ceiling test write-downs. FFO interest coverage was 8.9X for the year ending Sept. 30, 2006. — Charles Laporta

National Grid USA (A/Watch Neg/A-1)

The ratings remain on CreditWatch with negative implications, following the pending acquisition of KeySpan Corp. by parent-National Grid PLC (A/Watch Neg/A-1) for $7.3 billion (£4.2 billion) plus assumed debt of $4.5 billion (£2.6 billion). *We anticipate resolving the CreditWatch listing and lowering the ratings on National Grid USA and its subsidiaries by one* notch when the acquisition receives regulatory approval and becomes unconditional. Over the intermediate term, the acquisition of KeySpan and significant capital programs will likely weaken consolidated credit ratios, although National Grid USA should maintain stronger credit measures than the consolidated company. — Kenneth L. Farer

Nevada Power Co. (BB-/Stable/--)

See Sierra Pacific Resources — Swami Venkataraman

New England Power Co. (A/Watch Neg/A-1)

See National Grid USA	Kenneth L. Farer
New Jersey Natural Gas Co. (A+/Negative/A-1)	
The company continues to benefit from its attractive service area, above-average customer growth, and favorable regulation by the New Jersey Board of Public Utilities. These strengths are moderated by the greater risk of unregulated activities at its parent (New Jersey Resources Corp.). At Sept. 30, 2006, credit measures were appropriate for the current rating. However, New Jersey Natural Gas needs to demonstrate sustained performance and prudently financed growth projects in order for the outlook to return to stable.	Kenneth L. Farer
New York State Electric & Gas Corp. (BBB+/Stable/A-2)	
See Energy East Corp.	Ralph DeCesare
Niagara Mohawk Power Corp. (A/Watch Neg/--)	
See National Grid USA	Kenneth L. Farer
Nicor Gas Co. (AA/Negative/A-1+)	
See Nicor Inc.	Barbara Eiseman
Nicor Inc. (AA/Negative/A-1+)	
The financial trend has been declining from historically strong levels. However, due to lower debt levels and higher operating results in all of Nicor's business segments, certain financial metrics improved. In this regard, total debt to capital and funds from operations to total debt are hovering around 48% and 24%, respectively. Of credit concern is the Illinois Commerce Commission's review of the Nicor Gas' performance based rate plan in which various parties have filed for adjustments ranging from $108 million to $190 million. In addition, gas supply costs are open to the risk of hindsight prudence reviews by regulators, with 1999-2005 currently under review.	Barbara Eiseman
NiSource Inc. (BBB/Stable/--)	
Third quarter results improved due to lower interest expense, strong demand in the electric business, and improved gas distribution margins resulting from lower operating expenses. Certain key financial metrics remain subpar for the rating, with adjusted FFO to total debt at near 13% and total debt hovering around 60%. Reduced usage and customer attrition in the natural gas distribution segment may further pressure the company's financial profile.	Barbara Eiseman
North Shore Gas Co. (A-/Negative/A-2)	
See Peoples Energy Corp.	Jeanny Silva
Northeast Utilities (BBB/Stable/--)	
Northeast Utilities (NU) recently completed the sale of its competitive generation businesses, thereby improving the business profile. Capital spending levels are expected to be heavy in the next several years as NU builds out its transmission infrastructure in Connecticut and Southern New England. Access to capital market financing will likely be needed, despite $1 billion in asset sale proceeds. NU sees no need to raise equity in next two years and may increase debt leverage. NU's financial profile is slightly weak for the rating and is dependent on favorable regulatory actions over the next several years.	Ralph DeCesare
Northern Indiana Public Service Co. (BBB/Stable/--)	
See NiSource Inc.	Barbara Eiseman
Northern Natural Gas Co. (A/Stable/--)	
Structural ring-fencing provisions allow for a ratings separation from parent MidAmerican Holdings Co. Northern Natural Gas' stand-alone financials support the higher rating and Standard & Poor's expects continued solid stand-alone credit metrics. For the 12 months ended Sept 30, 2006, FFO coverage of interest and debt stood at 5.5x and 28%, respectively, while debt to capital was 43%. A rate settlement reached in 2005 will provide for rate stability until November 2007 .	Swami Venkataraman
Northern States Power Co. (BBB/Stable/A-2)	

See Xcel Energy Inc. — David Bodek

Northern States Power Wisconsin (BBB+/Stable/--)

The rating of this subsidiary of Xcel Energy Inc. reflects affiliation with the Xcel family of companies and the benefits of regulatory insulation. See Xcel Energy Inc. — David Bodek

Northwest Natural Gas Co. *(AA-/Stable/A-1)*

FFO interest coverage and FFO to total debt for the 12 months ended Sept. 30, 2006, stood at 4.4x and 19.8%, respectively. The company has a conservative hedging policy, but has increased cash flow exposure by reducing targeted hedge levels below those of prior winter seasons. Additional pipeline investments are being considered. TransCanada's Gas Transmission Northwest system and Northwest Natural are holding an open season for the new 220-mile Palomar Gas Transmission project, which could make gas purchases more competitive in the Northwest. The system could be configured to serve liquefied natural gas facilities that have been proposed for the Columbia River. — Michael Scholder

NorthWestern Corp. *(BB+/Watch Neg/--)*

Babcock & Brown Infrastructure Ltd. (BBI) is buying NorthWestern for $2.2 billion that will be financed with $505 million of new debt at an intermediate holding company, a mix of funds from BBI, and the assumption of NorthWestern's existing debt. NorthWestern's credit measures that are strong for the 'BB+' rating would weaken after the transaction closes in mid-2007 due to the incremental debt, which could put downward rating pressure on the company. Also, NorthWestern's pending Montana regulatory filings regarding a rate review and the acquisition may have cash flow implications. — Gerrit Jepsen

NRG Energy Inc. (B+/Stable/B-2)

The recent announcement of a sharp increase in near-term needs for capital expenditures to meet emissions compliance regulations leaves open the question of the amount of debt financing that will be needed to support the expanded capital program, as well as questions regarding management's oversight of such exposures. The ratings were affirmed upon the $1 billion-plus financing that enabled the company to reset its hedges to firm up the revenue stream over a longer horizon. Merchant exposure remains at the end of the hedge arrangements, which represents a key credit risk underlying the 'B+' rating. — David Bodek

NSTAR (A+/Stable/A-1)

NSTAR's pursuit of transmission and distribution activities and maintenance of a strong financial profile support the current ratings. Leverage remains weak with adjusted debt to capital of 67%, but should gradually decline because of higher retained earnings and minimal debt maturities. However, cash flow measures are acceptable at the current rating. — Kenneth L. Farer

NSTAR Gas Co. (A+/Stable/--)

See NSTAR — Kenneth L. Farer

OGE Energy Corp. *(BBB+/Stable/A-2)*

Funds from operations were up nearly 12% during the nine months ending September 2006 due to higher rates and favorable weather at OG&E and higher gross margins in every business line at Enogex. Adjusted credit metrics are adequate for the rating, with fully adjusted FFO to total debt at 28% for the 12 months ended September 2006 and adjusted debt to capital of 53%. New plans for increased capital expenditures could pressure ratings over the intermediate term. However, most of these expenditures are for regulated projects for which the company is expected to seek pre-approval. In July 2006, the company announced plans for OG&E to be a 42% partner in a new 950 megawatt coal unit at OG&E's existing Sooner plant expected to be cost approximately $1.8 billion. Should the project proceed, ratings stability would depend on the appropriate management of costs and on the level of regulatory support for the project. — Jeanny Silva

Ohio Edison Co. (BBB/Stable/--)

See FirstEnergy Corp. — *Todd Shipman*

Ohio Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Ohio Valley Electric Corp. (BBB-/Stable/--)

Operating trends are consistent but weak since Ohio Valley Electric (OVEC) operates on a cost recovery basis to serve power to its owner-customers, which are obligated to pay demand charges regardless of output as well as associated energy costs. Currently, its owner-customers are taking virtually all of the generation and pricing remains competitive at — Michael Scholder

about $32.5 per megawatt-hour for 2006. Coal inventories are adequate, despite upgrade work at the coal handling facilities for the Kyger Creek plant and slow inventory recovery due to competing barge traffic. Cash flow protection measures are very thin, with FFO coverage of interest of about 1.9x. Liquidity is acceptable, with $73.2 million in cash and a $200 million credit facility.

Oklahoma Gas & Electric Co. (BBB+/Stable/A-2)

See OGE Energy Corp. — Jeanny Silva

Orange and Rockland Utilities Inc. (A/Negative/A-1)

See Consolidated Edison Inc. — Kenneth L. Farer

Orion Power Holdings Inc. (B/Stable/--)

See Reliant Energy Inc. — Dimitri Nikas

Otter Tail Corp. (BBB+/Stable/--)

Credit metrics are adequate for the current rating category, with adjusted FFO to debt (including pension obligations) for the 12 months ending Sept 2006 at 26% and adjusted debt to capital (including pension obligations) at about 51%. Construction of Big Stone II (estimated to begin in summer 2007) could pressure the company's intermediate financial profile. Otter Tail currently estimates that during the 2006-10 period it will invest about $381 million in electric construction, including $247 million for Big Stone II, a 600MW coal-fired generation unit that the company will develop and operate for its own use and on behalf of six other regional participant-owners. — Jeanny Silva

Pacific Gas & Electric Co. (BBB/Stable/--)

Long-term electricity- and fuel-procurement activities are ongoing and will define the utility's operational and financial profile. The California Public Utilities Commission remains committed to providing relief in response to material changes in utility costs, which contributes to rating stability. The company exhibited gradual improvements in adjusted 12-month cash flow coverage measures as of Sept. 30, 2006 of 3.7x and FFO to debt of 24%, as compared with June 30, 2006 fully adjusted FFO interest coverage of 3.4x and FFO to total debt of about 18%. — David Bodek

PacifiCorp (A-/Stable/A-2)

Management remains focused on integrating PacifiCorp's six state operations into MidAmerican Energy Holdings (MEHC) and improving return on equity through improved regulatory relationships and cost reductions. For the 12 months ended Sept. 30, 2006, PacifiCorp's cash flow coverage of interest and debt stood at 3.3x and 16.6%, respectively, although ratings are driven by the consolidated credit quality of parent MEHC. Recent settlements in Utah and Oregon, while significantly below the original request, is consistent with expectations in our forecast. Rate proceedings are underway in Washington, which continues to be a challenge on cost allocation issues. We expect continued equity contributions from MEHC to finance PacifiCorp's $6.4 billion 5-year capex program. PacifiCorp has received $215 mill to date since the March 2006 acquisition. — Swami Venkataraman

PECO Energy Co. (BBB+/Watch Neg/A-2)

See Exelon Corp. — Jeanny Silva

Pennsylvania Electric Co. (BBB/Stable/--)

See FirstEnergy Corp. — Todd Shipman

Pennsylvania Power Co. (BBB/Stable/--)

See FirstEnergy Corp. — Todd Shipman

Peoples Energy Corp. (A-/Negative/A-2)

Peoples announced merger plans with WPS Resources Corp. (A/Watch Neg/A-1). Interim financials are negatively affected by the settlement charge related to gas purchase prudence proceedings that were settled in March 2006 and the write-off of $207 million of bad debt expense. Due to the outcome of the settlement agreement, the company had $107.3 million of expenses during the first nine months of fiscal year 2006 (which ends in September), and its financial measures deteriorated. The company's FFO interest coverage ratio dropped to 3.1x for the year ended June 30 2006, which is weak for the rating level. Leverage ratios, such as FFO to total debt of 12.2% and total debt to capital of 56.8% (increased short-term borrowing and the write-off from equity had negative effects), are also below benchmark levels. However, these charges are one-time occurrences and the merger of Peoples Energy and WPS should restore its — Jeanny Silva

balance sheet.

Peoples Gas Light & Coke Co. (The) (A-/Negative/A-2)

See Peoples Energy Corp. — Jeanny Silva

PEPCO Holdings Inc. *(BBB/Stable/A-2)*

The company's performance through 2007 should remain steady. The outcome of pending distribution rate filings in Maryland will be important since supportive regulation through rate increases would strengthen financial performance, easing strained cash flow measures due in part to power cost deferrals that began in mid-2006. — Gerrit Jepsen

Piedmont Natural Gas Co. Inc. (A/Stable/--)

Piedmont's financial performance remains appropriate for the rating, with FFO interest coverage in excess of 4x and FFO to total debt above 20%. The company has a 50% interest in Hardy Storage Co., which intends to build, own, and operate an underground interstate gas storage facility in West Virginia. — Todd Shipman

Pinnacle West Capital Corp. (BBB-/Stable/A-3)

Regulatory relationships continue to be a notable challenge for Pinnacle West Capital (PWCC) and its largest subsidiary, Arizona Public Service, with the utility's rate case expected to be a focus of 2006 and the first half of 2007. The company is requesting a 21% increase in retail electric rates. Recent staff recommendations of 9.8% suggest it may be difficult to restore the company's financial profile, which has been lagging, despite recent supportive efforts by the Arizona Corporation Commission to increase rates through a variety of temporary surcharges. Factors that are tempering financial performance include a base rate for fuel and purchased power benched to 2003 costs, a relatively weak power supply adjuster that has led to deferrals, and regulatory lag. Power cost deferral balances totaled about $209 million as of Sept. 30, 2006. — Anne Selting

Pivotal Utility Holdings (A-/Negative/--)

See AGL Resources Inc. — Michael Messer

PNM Resources Inc. (BBB/Negative/A-3)

Standard & Poor's expects near-term improvement to the credit metrics at PNM Resources, with proceeds of a recent equity issuance likely to go towards debt reduction, and PNM's announced joint venture with Cascade Investments, which is expected to be credit positive, if dividends from the venture are used to reduce balance sheet debt. Currently, key financial ratios at PNM Resources are stretched for the rating level; management has, however, communicated commitment to improve these ratios in the near term. — Chinelo Chidozie

Portland General Electric Co. (BBB+/Negative/A-2)

Higher operating costs and several forced outages at the 585 MW Boardman coal plant have resulted in weakened financial measures, with FFO to average total debt falling to a somewhat weak 18% for the 12 months ending Sept. 30, 2006, versus 22% for the similar period ending Dec. 31, 2005. The company will seek to recover related costs. In addition to the general rate case filed with the Oregon Public Utilities Commission in March 2006, the company has already filed for deferral of replacement power costs incurred through Feb. 5, 2006. Additional factors supporting the negative outlook include weak projected financial metrics, litigation surrounding the company's right to earn a return on its Trojan investment and the City of Portland's ongoing attempts to investigate its taxes and trading practices. — Leo Carrillo

Potomac Capital Investment Corp. (BBB-/Stable/NR)

See PEPCO Holdings Inc. — Gerrit Jepsen

Potomac Edison Co. (BB+/Positive/--)

See Allegheny Energy Inc. — Aneesh Prabhu

Potomac Electric Power Co. (BBB/Stable/A-2)

See PEPCO Holdings Inc. — Gerrit Jepsen

PPL Corp. (BBB/Stable/--)

In 2006, PPL Corp.'s merchant assets benefit from higher energy prices in the PJM region and the Pacific Northwest. Margins also benefit from a price escalator in its generation rate cap with PPL Electric Utilities. Adjusted debt to capital of — Aneesh Prabhu

55%, and FFO to debt of over 22% as of September 2006 were strong for the rating. Plant uprates and higher volumes on non-provider of last resort volumes will aid cash flow through 2007. Still, the company needs a sustained period of current price levels to fund projected capital spending needs on pollution-control equipment. To ensure sufficient cash flow, the company has signed a long-term coal contract with Consol Energy through 2018. Liquidity remains adequate with about $2 billion availability under PPL Energy's credit lines.

PPL Electric Utilities Corp. (A-/Stable/A-2)

The utility's financial profile continues to benefit from the last rate increase in 2004, which also provided for recovery of all PJM-related transmission costs and have resulted in FFO to debt at 20% and debt to capital of 53%, which are strong for the rating. Mild weather in the first half of 2006 affected earnings modestly. A lower court ruling revoked damages from a 2003 storm, but is being appealed. Operations continue to be in the top decile. — Aneesh Prabhu

PPL Energy Supply LLC (BBB/Stable/--)

See PPL Corp. — Aneesh Prabhu

Progress Energy Inc. (BBB/Positive/A-2)

Financial performance for the 12 months ending Sept. 30, 2006 improved as the fuel surcharge for PEF and PEC continue. Adjusted FFO to average debt improved to 15.5% compared with 14% in the prior year and the adjusted debt to capital is down to 60%. We expect this trend to continue as the company completes it debt reduction plan. — Jodi Hecht

PSEG Energy Holdings LLC (BB-/Negative/B-2)

Monetization of assets continues with the sale of generating facilities in Poland and RGE in Brazil. Tax deductions flowing from leasing transactions continue to be an important component of the company's cash flow, but spark spreads in Texas contributed meaningfully to revenues. We believe that Public Service Enterprise Group Inc. will not deploy cash generated at Public Service Electric & Gas Co. and PSEG Power LLC to infuse capital into PSEG Energy Holdings, which has experienced several failed investments. The outcome of an IRS investigation into tax deductions related to the company's lease portfolio represents a sizable contingent exposure. — Aneesh Prabhu

PSEG Power LLC (BBB/Negative/--)

See Public Service Enterprise Group Inc. — Aneesh Prabhu

Public Service Co. of Colorado (BBB/Stable/A-2)

See Public Service Enterprise Group Inc. — Aneesh Prabhu

Public Service Co. of New Hampshire (BBB/Stable/--)

See Northeast Utilities — Ralph DeCesare

Public Service Co. of New Mexico (BBB/Negative/A-3)

See PNM Resources Inc. — Chinelo Chidozie

Public Service Co. of North Carolina Inc. (A-/Stable/A-2)

See SCANA Corp. — Dimitri Nikas

Public Service Co. of Oklahoma (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Public Service Electric & Gas Co. (BBB/Negative/A-3)

See Public Service Enterprise Group Inc. — Aneesh Prabhu

Public Service Enterprise Group Inc. (BBB/Negative/A-3)

Meaningful debt reduction is contemplated, particularly with cash distributions from PSEG Energy Holdings. Adjusted — Aneesh

debt to capital, FFO to debt and FFO to interest of 60%, 16.3%, and 3.6x, respectively, as of Sept. 30, 2006 are weak for the rating, but cash flow over the next six months will benefit from revenue enhancements associated with the New Jersey Board of Public Utilities' latest wholesale electricity auction and from operational improvements. Electric and gas rate cases were approved at expected levels but the utility has agreed to avoid rate filings for three years, exposing it to cost increases in the interim. Merger proceedings with Exelon were terminated.	Prabhu
Puget Energy Inc. (BBB-/Stable/--)	
Regulatory support will be a decisive factor in driving possible rating improvement as the company implements a large $1.4 billion two-year capital program for 2006 and 2007, including construction of a major wind project by Dec. 2006 as well as the purchase of the operating 277 MW combined cycle Goldendale Energy Center. Balance sheet measures are adequate, but cash flow measures are somewhat weak, with FFO to total debt of just 9.9% for the 12 months ended Sept. 30, 2006.	Leo Carrillo
Puget Sound Energy Inc. (BBB-/Stable/A-3)	
See Puget Energy Inc.	Leo Carrillo
Questar Corp. (--/--/A-2)	
The E&P operations of Questar Market Resources (QMR) have benefited from high natural gas prices. QMR now constitutes about 80% of consolidated cash flow, but about 65% of gas and oil produced is hedged for 2007. Affiliation with Questar Gas and Questar Pipeline adds stability to Questar's consolidated cash flows, both in the short and long term. Gas supply offered through the Wexpro unit, which receives a 20% regulated return, is a significant positive. Financials are currently strong for the rating, with FFO to total debt at 70%, clearly buoyed by high commodity prices.	Ralph DeCesare
Questar Gas Co. (A-/Stable/--)	
See Questar Corp.	Ralph DeCesare
Questar Market Resources Inc. (BBB+/Stable/--)	
See Questar Corp.	Ralph DeCesare
Questar Pipeline Co. (A-/Stable/--)	
See Questar Corp.	Ralph DeCesare
Reliant Energy Inc. (B/Stable/--)	
On Nov. 28, 2006, Standard & Poor's revised the outlook to stable from negative to reflect Reliant's elimination of substantially all collateral requirements of the retail business. Reliant's retail business may benefit as the retail market evolves in Texas, especially if it can sustain current retail margin levels, providing support to credit quality. While credit protection measures continue to be weak for the rating, the redemption of $770 million in debt through the return of about $1 billion in cash collateral, coupled with the conversion of $275 million of convertible notes to equity, will improve the capital structure.	Dimitri Nikas
Reliant Energy Mid-Atlantic Power Holdings LLC (B/Stable/--)	
See Reliant Energy Inc.	Dimitri Nikas
Rochester Gas & Electric Corp. (BBB+/Stable/A-2)	
See Energy East Corp.	Ralph DeCesare
Rockland Electric Co. (A/Negative/A-1)	
See Consolidated Edison Inc.	Kenneth L. Farer
San Diego Gas & Electric Co. (A/Stable/A-1)	
We expect stable financial performance from San Diego Gas & Electric (SDG&E) and a reduction in dividends to parent Sempra Energy as SDG&E is entering a period of significant rate base growth in generation and transmission and is also in the process of contracting for substantial renewable assets. Cash flow coverages at the utility weakened in 2006 owing	Swami Venkataraman

to deferred tax reversals. Cash flow coverage of interest and debt dropped to 3.6x and 14.8%, respectively but are expected to return to historic levels. For the year 2005, the ratios were 4.9x and 26.7%, respectively.

Savannah Electric & Power Co. (A/Stable/--)

See Southern Co. — Terry Pratt

SCANA Corp. (A-/Stable/--)

SCANA's credit protection measures have weakened when compared with the 12 months ending Sept. 30, 2005, but remain adequate for the rating. The consolidated financial risk profile benefits from strong cash flow and a moderation in the capital spending program. — Dimitri Nikas

Scottish Power Finance U.S. (A-/Watch Neg/--)

The ratings on Scottish Power Finance (SPFUS) were placed on CreditWatch with negative implications on Dec 4, 2006. This follows a similar action on the 'A-' long-term corporate credit ratings on Scottish Power PLC and its subsidiaries following Spanish utility Iberdrola S.A.'s announcement on Nov. 28 of a recommended €17.1 billion cash and share offer to acquire Scottish Power. SPFUS serves as the guarantor for unrated operations of PPM Energy and the energy trading business of PPM Energy Canada Ltd., which constitute substantially all of Scottish Power's operations in North America. It is unclear if Iberdrola will renew the unconditional guarantee and support agreement that Scottish Power UK plc extended and which underpinned SPFUS' credit quality. — Swami Venkataraman

SEMCO Energy Inc. (BB-/Positive/--)

SEMCO's financial condition has improved over the past two years. Standard & Poor's improved its business risk profile score for SEMCO to '4' from '5', reflecting management's focus on core regulated gas distribution operations. SEMCO is still highly dependent on upcoming favorable regulatory rulings, including the filing of an increase in base rates of $18.9 million, with a ruling expected in the second quarter of 2007. Liquidity remains below average, and its bank line contains relatively tight covenants. — Ralph DeCesare

Sempra Energy (BBB+/Stable/A-2)

Consistent and predictable financial performance is expected at the utilities and Sempra Generation. Significant ongoing capital expenditures at the utilities, liquid natural gas projects and the Rockies Express pipeline limit the amount of debt that can be paid down. Under conservative assumptions for Sempra Commodities, ratios are expected to be weak for the rating in 2006 and 2007, with funds from operations interest coverage and debt somewhat lower than 4x and 23%, respectively, due to substantial investment in liquefied natural gas and pipelines businesses without any cash flows. For the 12 months ended Sept. 30, 2006, these ratios stood at 4x and 20.8%, respectively. Successful completion of asset sales raised over $1.2 billion, which will support ratios during a period of substantial capital expenditures while also sharpening the gas infrastructure focus of the company — Swami Venkataraman

Sierra Pacific Power Co. (BB-/Stable/--)

See Sierra Pacific Resources — Swami Venkataraman

Sierra Pacific Resources (BB-/Stable/B-2)

On Sept. 22, 2006, Standard & Poor's raised the corporate credit rating on Sierra Pacific Resources (SRP) and its subsidiaries to 'BB-' from 'B+', reflecting the cumulative impact of improved business and financial risk profiles. The business risk score improved to a '5' from a '6' owing to a substantially improved regulatory relationship and asset acquisitions that have significantly reduced the utilities' short capacity position. Prospects for future upgrades will be challenged by the substantial capital expenditures at the utilities that will limit the ability to pay down debt. For the 12 months ended Sept. 30, 2006, FFO coverage of interest and debt stood at 2.8x and 12.3%, respectively, adequate for the rating. We forecast similar ratios in the next few years but expect them to weaken during the construction of the Ely Center project. — Swami Venkataraman

South Carolina Electric & Gas Co. (A-/Stable/A-2)

See SCANA Corp. — Dimitri Nikas

South Jersey Gas Co. (BBB+/Stable/--)

South Jersey Gas Co. continues to benefit from an attractive service area, above-average customer growth, and favorable regulation by the New Jersey Board of Public Utilities. These strengths are moderated by the greater risk of unregulated activities at its parent (South Jersey Industries Inc.). As of Sept. 30, 2006, South Jersey Gas' credit measures were appropriate for the current rating. Over the near term, financial ratios should benefit from moderate spending on unregulated pursuits, prudent financing of growth strategies, and increased portion of consolidated cash — Kenneth L. Farer

flow from the regulated gas utility.

Southern California Edison Co. (BBB+/Stable/A-2)

This utility's rating will continue to reflect the interplay between its affiliation with weaker, unregulated, competitive energy companies and the strong regulatory and statutory protections that limit the extent to which the regulated utility can be called upon to provide capital contributions to unregulated affiliates. The California Public Utilities Commission remains committed to providing relief in response to material changes in utility costs, which contributes to rating stability. The company's stand-alone adjusted cash flow coverage ratios were strong at 5.6x FFO interest coverage and FFO to total debt of 31% as of Sept. 30, 2006. — David Bodek

Southern California Gas Co. (A/Stable/A-1)

The company continues to generate solid and predictable earnings and cash flows. FFO coverage of interest and debt stood at a very strong 6.6x and 33.1%, respectively for the 12 months ended Sept. 30, 2006. With capital expenditures in line with historical averages, dividends to parent Sempra are expected to be maintained. — Swami Venkataraman

Southern Co. (A/Stable/A-1)

Retail kilowatt-hour sales were up 2.4% for the first nine months of 2006 compared with the same period in 2005, mostly from customer growth and weather. Customer growth was 1.4% for the same period. Adjusted FFO to interest coverage was 5x for year ended Sept. 30, 2006, and should be around 5x through 2008. FFO to total debt was about 23%. Cash flow should grow modestly through 2007 due to continued customer growth and the lack of regulatory filings. Favorable to credit is Mississippi Power's receipt of a $276 million Community Development Block Grant from the Mississippi Development Authority to offset the $302 million in cost to repair damage caused primarily by Hurricane Katrina. Remaining costs are likely to be covered through state restoration bonds. — Terry Pratt

Southern Connecticut Gas Co. (BBB+/Negative/--)

See Energy East Corp. — Ralph DeCesare

Southern Electric Generating Co. (A/Stable/A-1)

See Southern Co. — Terry Pratt

Southern Indiana Gas & Electric Co. (A-/Stable/--)

See Vectren Corp. — Gerrit Jepsen

Southern Power Co. (BBB+/Stable/A-2)

The FERC settlement in October 2006 of Southern Co. affiliate abuse case that now governs certain aspects of Southern Power's business should not have a material effect on the company's future financial performance. Southern Power continues to digest recent plant acquisitions in Florida and North Carolina made in summer 2006. For 2006 to 2008, FFO interest coverage averages 3.6x, FFO to average total debt averages 19%, and leverage will remain slightly below 60% - assuming current acquisitions and contracts agreements close as planned. For the twelve months ended Sept 30, 2006, FFO/interest coverage was 3.4x. — Terry Pratt

Southwest Gas Corp. (BBB-/Stable/--)

Credit measures are solid for the rating, and have begun to show signs of improvement in 2006 with increased rate relief in Arizona. Cash flow measures are particularly strong, with FFO to debt at 15% for the 12-month period ended Sept. 30, 2006, driven in part by the operating margin contribution of continued customer growth and rate relief in Arizona but *offset slightly by the effects of another mild winter. Improving regulatory treatment in Nevada, where the company* currently has a pending request for a weather normalization adjustment mechanism, could provide further improvement to the company's regulatory profile. — Leo Carrillo

Southwestern Electric Power Co. (BBB/Stable/--)

See American Electric Power Co. Inc. — Todd Shipman

Southwestern Public Service Co. (BBB/Stable/A-2)

See Xcel Energy Inc. — David Bodek

System Energy Resources Inc. (BBB-/Watch Neg/--)

See Entergy Corp. — Dimitri Nikas

Tampa Electric Co. (BBB-/Stable/A-3)

Tampa Electric Co.'s cash flow continues to benefit from deferred fuel cost recovery, partial funding of elevated capital spending for environmental compliance and incremental peaking capacity, despite lower retail sales growth compared to the previous 12 months. The utility's ratings are supported by strong customer growth, minimal reliance on industrial load, a strong regulated local gas distribution unit, and a supportive regulatory environment. — Jodi Hecht

TECO Energy Inc. (BB/Stable/B-1)

TECO Energy Inc. has completed selling substantially all its merchant power assets and is refocused on its core regulated business. Its utility, Tampa Electric, is concentrating on meeting the strong demand growth of its market. The company continues to build cash and refinance opportunistically ahead of sizable 2007 maturities. Cash flow has improved with the collection of the past under recovered fuel surcharge. While synthetic fuel operations resumed in September 2006, the idling of the operations during the year, which make up a substantial component of consolidated cash flow, reduced excess cash flow and slowed the pace of debt reduction. Debt incurred to pursue a merchant strategy continues to drag on financial measures and credit quality. — Jodi Hecht

Texas-New Mexico Power Co. (BBB/Negative/--)

See PNM Resources Inc. — Chinelo Chidozie

Thermal North America Inc. (BB-/Stable/--)

Our October 2006 rating affirmation factored in Thermal North America's (TNA) senior loan debt refinancing and acquisition of district heating and cooling assets in Los Angeles and Las Vegas, which provide about 19% of cash flow from 2007 to 2009. We view the business as stable and expect TNA to generate modestly growing cash flow. FFO to interest expenses was about 2.4x for the twelve months ended June 30, 2006. Until loan maturity in 2009, adjusted FFO to interest expense ratio is forecast at about 2.4x, which is adequate for the rating. Adjusted FFO to total debt is forecast at 11% to 12%, which is low for the rating. The company's adjusted total debt to capitalization is high but falls into the high 50% range with debt retirement and with a mandatory $30 million equity infusion in 2008. — Terry Pratt

Toledo Edison Co. (BBB/Stable/--)

See FirstEnergy Corp. — Todd Shipman

Tucson Electric Power Co. (BB/Stable/B-1)

Strong cash flows are an important credit attribute of this very leveraged company, with parent UniSource expecting to fund rising capital expenditures internally and slowly work toward paying down Tucson Electric's debt and capital lease balances. Due to a rate cap in place through December 2008, Tucson Electric remains vulnerable to unplanned outages at its coal plants, but strong performance of the units are assisting in significant improvement in cash flow metrics. Year to date cash flows from operations have improved, at about $273 million, relative to 2005 when the company experienced an unplanned summer outage at one of its important coal plants. — Anne Selting

TXU Corp. (BBB-/Negative/--)

For the 12 months ended Sept. 30, 2006, financial performance was solid, and favorable market prices and the hedge program should support stable cash flows through 2007. Adjusted FFO to interest was 5.5x and adjusted FFO to average total debt was about 32%. Leverage, which is very high compared with peers, dropped to 88% from about 96% at year-end 2005. TXU reduced short-term debt balances by $1.3 billion in the third quarter with operating cash flow. Retail customers declined 5.5% for the 12 months ended Sept. 30, 2006. TXU continues to be exposed to the planned $10 billion or so nonrecourse project to build out 11 coal plants totaling 9,000 MW by year-end 2010 because TXU has placed orders for long-lead items without having permits. — Terry Pratt

TXU Electric Delivery Co. (BBB-/Negative/--)

See TXU Corp. — Terry Pratt

TXU Energy Co. LLC (BBB-/Negative/--)

See TXU Corp. — Terry Pratt

TXU U.S. Holdings Co. (BBB-/Negative/--)

See TXU Corp. — Terry Pratt

Union Electric Co. d/b/a AmerenUE (BBB-/Watch Neg/A-2)

See Ameren Corp.	Barbara Eiseman

United Water New Jersey (A-/Watch Pos/--)

See United Waterworks	Plana Lee

United Waterworks (A-/Watch Pos/--)

The Suez and GDF merger can be consummated only by July 1, 2007, as per a ruling by the constitutional court. The deal now faces greater uncertainty on account of possible political developments during the elections in April 2007, as well as Suez's shareholders' demand for an increase in the special dividend. In the event of a merger being completed, the rating on the United Water entities will depend on the strategy of the merged entity for its water segment in U.S.	Plana Lee

Vectren Corp. (A-/Stable/--)

Vectren Corp.'s southern Indiana operations recently filed for electric and gas rate increases. Indiana commission decisions are expected in mid-2007. The rate filing includes credit supportive requests for a tracker to recover bare steel/cast iron pipeline replacement costs and to recover more gas utility costs through fixed charges instead of variable charges. Vectren's northern Indiana gas utility and Ohio gas utility operations already are recovering a greater level of costs through fixed charges. Such regulatory mechanisms should help maintain stable cash flow and bolster creditworthiness during pipeline replacement. Unregulated activities continue to provide positive income at an arm's length and mostly support regulated operations. Financial ratios remain in line with expectations and the rating.	Gerrit Jepsen

Vectren Utility Holdings Inc. (A-/Stable/A-2)

See Vectren Corp.	Gerrit Jepsen

Virginia Electric & Power Co. (BBB/Positive/A-2)

See Dominion Resources Inc	Aneesh Prabhu

Washington Gas Light Co. (AA-/Negative/A-1)

See WGL Holdings Inc.	Jeanny Silva

West Penn Power Co. (BB+/Positive/--)

See Allegheny Energy Inc.	Aneesh Prabhu

Westar Energy Inc. (BB+/Positive/--)

Third quarter results improved due to increased retail electric sales (primarily industrial sales), implementation of a fuel adjustment mechanism, favorable mark-to-mark contract valuations related to energy marketing transactions, lower interest expense, and increased corporate-owned life insurance proceeds, offset somewhat by reduced wholesale sales and higher operations and maintenance expenses. Certain key financial metrics also strengthened and are marginally commensurate with investment grade levels. The Kansas Court of Appeals' rejection in July 2006 of parts of the Kansas Corporation Commission's December 2005 rate order could lead to a material rate reduction or customer refund, thereby affecting Westar's steady financial improvement.	Barbara Eiseman

Western Massachusetts Electric Co. (BBB/Stable/--)

See Northeast Utilities	Ralph DeCesare

WGL Holdings Inc. (AA-/Negative/A-1)

Credit metrics remain somewhat weak for the rating. Fully adjusted debt to capital was roughly 53% at the end of fiscal year 2006 (ending in September). Exposure to declining customer usage in Virginia and Washington, D.C., regulatory lag related to the recovery of moderate pipeline rehabilitation and conditioning facility capital expenditures ($156 million) in Maryland, and exposure to volatile retail marketing activities are pressuring ratings. Washington Gas Light has filed a rate case in Virginia requesting among other things access to a revenue normalization adjustment, which would reduce the company's exposure to conservation-related cash flow volatility.	Jeanny Silva

Wisconsin Electric Power Co. (A-/Negative/A-2)

See Wisconsin Energy Corp.	Gerrit Jepsen
Wisconsin Energy Corp. (BBB+/Negative/A-2)	
Wisconsin Energy's financial measures have been mixed for the rating during its heavy construction program, but cash flow protection measures have strengthened following the last rate increase. Sustaining this improvement will depend on supportive rate treatment and prudent execution of the capital spending program, both of which are expected to occur. We will continue to watch for any decision by the company regarding its Point Beach Nuclear Power Plant, and what effect, if any, there would be on financial measures.	Gerrit Jepsen
Wisconsin Gas LLC (A-/Negative/A-2)	
See Wisconsin Energy Corp.	Gerrit Jepsen
Wisconsin Power & Light Co. (A-/Stable/A-2)	
See Alliant Energy Corp.	Jeanny Silva
Wisconsin Public Service Corp. (A/Watch Neg/A-1)	
See WPS Resources Corp.	Jeanny Silva
WPS Resources Corp. (A/Watch Neg/A-1)	
Cash demands continue to be high reflecting completed or pending acquisitions, the construction of the Weston 4 plant at Wisconsin Public Service Corp. (WPSC), and higher working capital requirements at WPS Energy Services Inc. These factors have contributed to high debt levels, which continue to pressure the company's cash flow protection metrics. For the 12 months ending September 2006, fully adjusted (including pension and other postemployment benefit adjustments) FFO interest coverage was 3.3x. For the same period, fully adjusted FFO to debt was only 12%. Before WPS announced its merger with Peoples Energy, Standard & Poor's had expected credit metrics at WPS Resources to improve over the next year or two. Improvement was contingent on fully integrating the recently acquired Michigan and Minnesota gas utility assets and getting Weston 4 completely in rate base at WPSC. The Peoples merger could complicate the company's ability to stabilize its financial condition at the current rating level.	Jeanny Silva
Xcel Energy Inc. (BBB/Stable/A-2)	
Xcel Energy's several utility subsidiaries are engaged in numerous federal and state rate proceedings that will be important determinants of future credit quality. Significant additions of debt in support of the capital program in 2006 led to the erosion of some key credit metrics. The adjusted 12-month FFO interest coverage declined to 3.14x due to increased, but nonrecurring, tax payments in the most recent quarter. Adjusted FFO to total debt was about 16x during this period.	David Bodek
Yankee Gas Services Co. (BBB/Stable/--)	
See Northeast Utilities	Ralph DeCesare
York Water Co. (The) (A-/Stable/--)	
The company should continue to grow organically and through small acquisitions. Repayment of short-term debt from proceeds of long-term debt and expected issuance of equity should strengthen credit metrics. However, upward rating potential in the near term is unlikely, given the company's lack of free cash flow and high capital expenditures expected going forward. The company's debt leverage has increased to about 57% while FFO interest coverage remained above 3x for the 12 months ending September 2006.	Plana Lee

Ratings are as of Jan. 5, 2007.

Quarterly Rating Activity

Table 2

Recent Rating/Outlook/CreditWatch Actions

Issuer	To	From	Date	Reason
Baltimore Gas & Electric Co.	BBB+/Negative/A-2	BBB+/Watch Pos/A-2	Oct. 25, 2006	See Constellation Energy Group Inc.

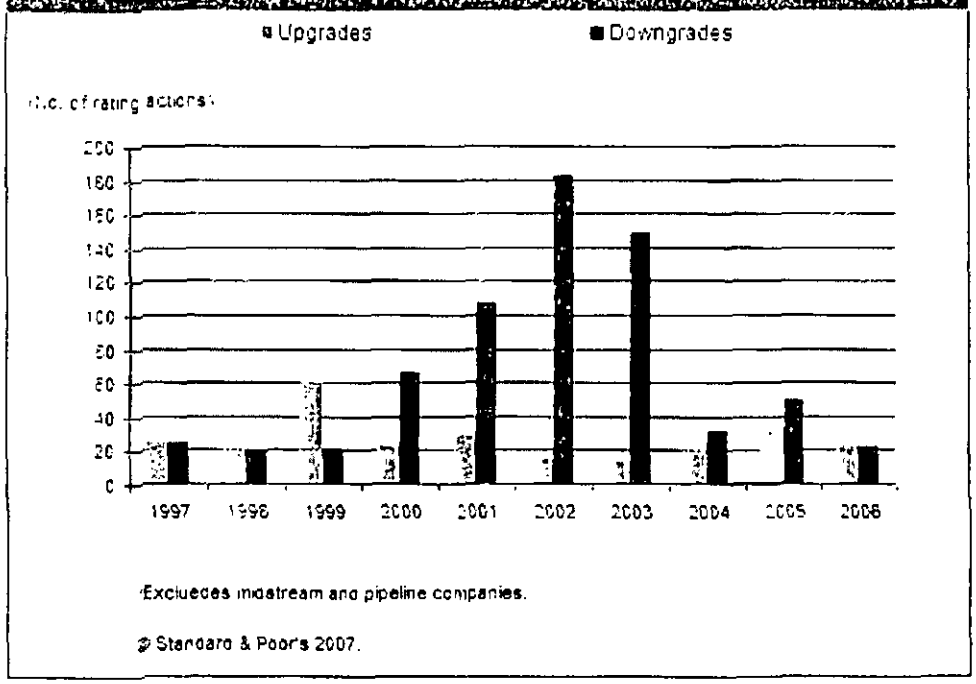
Consolidated Natural Gas Co.	BBB/Positive/A-2	BBB/Stable/A-2	Nov. 2, 2006	See Dominion Resources Inc.
Constellation Energy Group Inc.	BBB+/Negative/A-2	BBB+/Watch Pos/A-2	Oct. 25, 2006	The removal of CreditWatch with positive implications follows the termination of merger discussions with The FPL Group Inc.
Dominion Resources Inc.	BBB/Positive/A-2	BBB/Stable/A-2	Nov. 2, 2006	The outlook revision follows Dominion's announcement that it proposes to sell a majority of its exploration and production assets.
Edison Mission Energy	BB-/Stable/NR	BB-/Positive/NR	Dec. 14, 2006	The outlook was revised after the company announced that it will need to invest $2.7 billion to $3.4 billion between 2008 and 2018 to meet emissions controls at the power plants in the Midwest Generation portfolio.
Edison Mission Marketing and Trading	BB-/Stable/--	BB-/Positive/--	Dec. 14, 2006	See Edison Mission Energy
Florida Power & Light Co.	A/Stable/A-1	A/Watch Neg/A-1	Oct. 26, 2006	See FPL Group Inc.
FPL Group Capital Inc.	A/Stable/A-1	A/Watch Neg/A-1	Oct. 26, 2006	See FPL Group Inc.
FPL Group Inc.	A/Stable/--	A/Watch Neg/--	Oct. 26, 2006	The removal of the ratings from CreditWatch with negative implications follows the termination of merger discussions with Constellation Energy Group Inc.
Michigan Electric Transmission Co	BBB/Positive/--	NR	Nov. 9, 2006	The ratings reflect the consolidated credit profile of the holding and its utility subsidiaries, Michigan Electric Transmission, and electric transmission utility International Transmission Co.
Orion Power Holdings Inc	B/Stable/--	B/Negative/--	Nov. 28, 2006	See Reliant Energy Inc.
Reliant Energy Inc.	B/Stable/B-2	B/Negative/B-2	Nov. 28, 2006	The outlook revision reflects the fact that the company's liquidity concerns have been addressed. The stable outlook also reflects Standard & Poor's expectation that Reliant Energy may benefit as the retail market evolves in Texas, sustaining current retail margin levels and improving its financial performance.
Reliant Energy Mid-Atlantic Power Holdings LLC	B/Stable/--	B/Negative/--	Nov. 28, 2006	See Reliant Energy Inc.
Scottish Power Finance U.S.	A-/Watch Neg/--	A-/Stable/--	Dec. 1, 2006	The CreditWatch listing is a result of the pending acquisition of ScottishPower by Iberdrola, which could be finalized by April 2007.
SEMCO Energy Inc.	BB-/Positive/--	BB-/Stable/--	Oct. 31, 2006	The positive outlook reflects the potential for a higher rating based on SEMCO's ability to reduce debt and increase free cash flow, continue to work successfully with its bank group and regulators, and continue to focus on core regulated operations.
Virginia Electric & Power Co.	BBB/Positive/A-2	BBB/Stable/A-2	Nov. 2, 2006	See Dominion Resources Inc.

*Dates represent the period from Oct. 25, 2006 to Jan. 5, 2007 covered by this report card.

Ratings Trends

Chart 3

U.S. Utility Upgrades Versus Downgrades



Selected Articles

Table 3

Previously Published U.S. Utilities Articles

Article title	Published date
Credit FAQ: Potential Rate Freeze Legislation In Illinois Would Jeopardize Ratings On Exelon And Ameren Units	Nov. 20, 2006
Key Credit Factors: U.S. Merchant Electric Generation Continues To Evolve	Dec. 22, 2006
Recovery Report: Boston Generating LLC's $1.8 Billion Recapitilazation Financing	Dec. 4, 2006
Recovery Report: Reliant Energy Inc.'s $1.4 Billion Facilities	Nov. 2, 2006
Regulatory Support Is Key For U.S. Utilities Building New Coal-Fired Power Plants	Nov. 3, 2006
Request For Comments: Imputing Debt To Purchased Power Obligations	Nov. 1, 2006

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Table 4

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Request For Comments: Imputing Debt To Purchased Power Obligations

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Adjusting Financial Ratios
Conclusion

Standard & Poor's Ratings Services is requesting comments from market participants about one specific element of its refined methodology for imputing debt to purchased power obligations involving utility companies.

Proposal Summary

Standard & Poor's is abandoning its practice of not imputing debt for purchased power agreements (PPA) with terms of three years or less. In addition, where there is a high probability that the utility will have an ongoing obligation to serve load beyond the nominal tenor of short-term contracts, which is almost always the case, Standard & Poor's is contemplating providing evergreen treatment to PPA obligations to reflect the long-term load serving obligations borne by utilities. Unless an electric utility faces a declining population or real prospects of customer migration to other suppliers, both of which are rare, any near-term or intermediate power supply contracts will need to be renewed or replaced with contracted or self-built capacity to continue to meet load obligations.

We acknowledge that the process of providing evergreen treatment to outstanding contracts is imprecise. Uncertainties surround the level of capacity prices that should be assumed and the duration for which contracts should be extended to reflect the load-serving obligation. Therefore, we welcome input on evergreen-related issues as we refine these aspects of the criteria.

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Response Deadline

Please submit your comments on this proposal through Dec. 15, 2006, to criteriacomments@standardandpoors.com

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Imputation Is Important For Credit Analysis

Standard & Poor's has for many years considered PPAs as financial obligations that electric utilities incur when they elect to purchase rather than build their own capacity, and this obligation has affected our view of utilities' creditworthiness. Standard & Poor's has historically applied a "risk factor" of 0% to 100% to the net present value (NPV) of the PPA capacity payments, and capitalized this amount. The risk factor's role is to calibrate the stringencies of debt imputation relative to our evaluation of the certainty of recovery of power purchase costs by virtue of regulatory and legislative protections. The imputation of debt and debt service is important to our credit analysis because the resulting financial adjustments affect several key credit metrics used when we assess credit quality.

The risk factor acts as a proxy for the proportion of risk borne by the utility. At 100%, all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers.

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Reviewing Existing Criteria--And A Few Refinements

From time to time, Standard & Poor's has revisited the methodology employed for making the financial adjustments that incorporate the obligations created by PPAs in its credit evaluations. This article discusses the most recent refinements. It also includes a discussion of additional areas that are under consideration as potential future refinements to our ratings methodology. While we expect very modest, if any, rating changes to result from these modifications, the proposed modifications are being disseminated in this article in the interest of ensuring the ongoing transparency of our rating methodology.

Standard & Poor's published its original PPA criteria in 1991, and provided updates in 1993 and 2003. During this time, the industry has established a very strong track record of demonstrating the viability and effectiveness of the various recovery mechanisms that state regulators have established for costs associated with contracted generation capacity. Recovery mechanisms have largely performed as intended, and related write-offs have proven to be very low. These results justify the continued application of risk factors that serve to temper, often substantially, the amount of debt imputation. Ensuring meaningful comparability in the financial commitments among utilities that are building and those that are purchasing capacity to satisfy load obligations is the rationale for our imputation of debt and debt service for PPAs. PPAs essentially represent substitutes for direct, debt-financed, capital investments. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. The analytical goal of our financial adjustments for PPAs is to reflect the fixed obligation in a way that depicts any credit exposure that is added by the presence of PPAs. That said, a PPA also shifts various risks to the supplier, such as construction risk and most of the operating risk. As a result, the principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates. While it is the

utility that must of course make these payments, however, to the extent that regulators and, in certain cases, legislatures, have structured recovery to assign the burden to ratepayers, the utilities' risk diminishes.

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Refinements To The Methodology

With only modest liberalization of the treatment of PPAs, we are perpetuating the current ratings criteria. Current guidelines for utilities whose capacity payments are recovered in base rates provides for the application of a 50% risk factor to the NPV of the capacity payments. This approach will continue. The NPV is calculated using the utility's average cost of debt (excluding securitization debt), rather than the standardized 10% discount rate used previously. For purposes of adjusting cash flow measures, implied interest expense is calculated on the imputed debt amount. This is accomplished by applying the average cost of debt to the relevant year's imputed debt level.

To date, where PPA capacity costs were recovered through a fuel adjustment clause (FAC), as compared with base rate recovery, a risk factor of 30% has been generally used in lieu of the 50% risk factor. We view the recovery of the capacity component of a PPA through a FAC as providing greater certainty and timeliness than recovery through a base rate mechanism. (The base rate mechanism generally has greater potential for under-recovery due to variations in volume sales and fluctuations in fuel prices over time.) Based on the effectiveness of FAC mechanisms, we will adjust modestly the risk factor of 30% down to 25%.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still do not amount to pure FACs. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, a risk factor between the revised 25% FAC risk factor and the 50% risk factor will be employed in calculating adjusted ratios.

In those instances where recovery of PPA-related capacity costs is guaranteed by a legislative mechanism, the level of the risk factor will be determined by the timeliness provided by the legislative true-up mechanism. The strength of the mechanism can result in risk factors as low as 0% because legislatively prescribed recovery mechanisms are viewed as providing utilities with a greater level of protection than that provided by regulatory orders.

There are a number of utilities to which Standard & Poor's does not impute any PPA-related debt. Specifically, Standard & Poor's does not impute debt for supply arrangements if a utility acts merely as a conduit for the delivery of power (e.g., because it has been transformed into a pure transmission and distribution utility by regulators or legislation that has directed the divestiture of all generation assets). For example, in New Jersey, the vertically integrated utility companies were transformed into pure transmission and distribution utilities. The state commission, or an appointed proxy, leads an annual auction in which suppliers

bid to serve the state's retail customers, and the utilities are protected from supplier default. In New Jersey, the power supply function of the state's utilities has essentially been reduced to the delivery of power and the collection of revenues from retail customers on behalf of the suppliers. Therefore, while Standard & Poor's has continued to impute debt to New Jersey's utilities for qualifying facility and exempt wholesale generator contracts to which the utilities are parties, we do not do so for other electricity supply contracts where the utilities merely act as conduits between the winners of the regulator's supply auction and the end-user, retail customers.

Finally, Standard & Poor's is abandoning the practice of not imputing debt for contracts with terms of three years or less. In addition to abandoning our historical three-year rule, we are contemplating applying an evergreen mechanism for short-term contracts. Because expiring contracts must be replaced with either debt-financed capacity additions or replacement PPAs for regulated utilities to meet load serving obligations, Standard & Poor's must look beyond the termination of near-term and intermediate-term contracts to approximate the fixed obligations that will succeed the current contracts in evaluating a utility's financial profile.

The process of providing evergreen treatment to outstanding contracts is imprecise. Uncertainties surround the level of capacity prices that should be assumed and the duration for which contracts should be extended to reflect the load-serving obligation. Therefore, we welcome input on evergreen-related issues as we refine these aspects of the criteria over the next 45 days.

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Adjusting Financial Ratios

Standard & Poor's determines the debt equivalence that it will add to a utility's balance sheet as a result of being a party to a PPA by calculating the NPV of the annual capacity payments over the life of the contract because it is the capacity payment that represents the vehicle that funds the recovery of the supplier's investment in the generation asset.

Where the PPA contract price is stated as a single, all-in energy price, Standard & Poor's will use a proxy capacity charge, stated in dollars per kilowatt-year, and multiply that figure by the number of kilowatts under contract. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine. This is a departure from the historical practice of simply halving all-in energy payments and assuming a one-to-one ratio of energy to capacity payments. This new element of the rating methodology will also be applied to generation with extremely low variable costs whose price is stated as an all-in energy price, such as nuclear and wind generation.

The discount rate used in calculating an NPV, imputed debt, and imputed interest expense is the utility's average interest rate on its outstanding debt (excluding securitization related debt). Standard & Poor's multiplies the NPV of the stream of capacity payments by the appropriate risk factor, which will generally be

25% for capacity payments that are recovered through fuel adjustment clauses and 50% for capacity payments that are recovered in base rates. This amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense by multiplying a given year's NPV of PPA-related capacity payments by the risk factor and the company's average interest rate on outstanding debt. The resulting number is added to reported interest expense to calculate adjusted interest coverage ratios.

Key ratios affected include:

- Balance sheet debt is increased by the calculated NPV of the stream of capacity payments, after the application of the risk factor, which is added to the numerator and denominator in calculating an adjusted debt-to-capitalization ratio;
- The implied interest expense derived from applying the average interest rate to the NPV figure is simultaneously treated as a reduction in power purchase expenses and added to interest expense for the calculation of the adjusted funds from operations (FFO) to interest ratio; and
- The FFO to total debt ratio is adjusted by adding the NPV of capacity payments, after the application of the risk factor, to debt in the denominator and an implied depreciation expense is added to FFO.

The depreciation expense adjustment, the last element of the principal financial adjustments cited above, represents a new element within the context of financial adjustments for PPAs (though it has been a long-standing component of the analytical adjustments for leases). Adding an implied depreciation expense to FFO is another element that aligns the analytical treatment of PPAs with the concept of purchased power as a substitute for self-build. The depreciation expense adjustment is a vehicle for capturing the ownership-like attributes of the contracted asset and has the effect of mitigating some of the ratio impact of debt imputation.

The mechanics of these adjustments are illustrated in the table.

Adjustments To Ratios						
(Mil. $)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Funds from operations	2,500					
Interest expense	650					
Directly issued debt	10,000					
Shareholders' equity	9,000					
Fixed capacity commitments	500	500	500	500	500	4,000
NPV of fixed capacity commitments						
Using a 6.5% discount rate	4,079					
Applying a 25% risk factor	1,020					
Unadjusted ratios						

FFO/interest (x)	4.9					
FFO/total debt (%)	25					
Debt/capitalization (%)	53					
Ratios adjusted for debt imputation						
FFO/interest (x)*	4.6					
FFO/total debt (%)¶	23					
Debt/capitalization (%)§	55					

*Adds implied interest to the numerator and denominator. Also adds implied depreciation to the numerator. ¶Adds implied depreciation to the numerator and adds implied debt to total debt. §Adds implied debt to both the numerator and the denominator.

Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. The NPV of the PPA will typically decrease as the maturity of the contract approaches, but on a portfolio basis, the overall NPV may remain somewhat static as old contracts roll off and new ones are executed.

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Conclusion

Absent legislative assurance of recovery, or an obligation that is little more than a fiduciary role for a transmission and distribution utility, PPAs constitute a financial risk by adding fixed obligations, though history is clearly on the side of full recovery. There is ample evidence that utility regulators and commissions have intended these costs to be for the account of the ratepayer, which justifies the continued use of risk factors. The modest revisions to our methodology seek to perpetuate our use of financial adjustments that reflect the legislative and regulatory protections that mitigate regulated utilities' exposure to the fixed obligations created by PPAs.

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STANDARD & POOR'S RATINGSDIRECT

RESEARCH

No Major Shifts In U.S. Utilities' Pension Funding Status

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(The authors would like to acknowledge Trupti Dhamankar and Masako Kuwahara for their contributions to this commentary.)

Standard & Poor's Rating Services has begun including standard post-retirement obligation adjustments in its calculation of regulated utility issuers' financial statistics. Because pension and other postretirement benefit obligations are ultimately recoverable in rates, shortfalls are not considered to be an acute credit factor, and Standard & Poor's historically has not adjusted its ratios for these items. These adjustments will now appear in our published reports for regulated utilities.

The most common postretirement obligations are pensions and retiree medical benefits. We have always acknowledged that large underfunded postretirement obligations could lead to a loss of flexibility for a utility in the long run, and have always incorporated this in our analyses. Therefore, we do not expect ratings will change solely because of this modification.

However, if Standard & Poor's is not comfortable with the ultimate recoverability of a shortfall in rates, this will negatively affect the business risk profile. Meanwhile, if utilities have booked a regulatory asset, and Standard & Poor's is comfortable with the ultimate recoverability of that regulatory asset, it will positively affect the business profile score.

After reviewing pension funding status for regulated entities for three consecutive years, we have concluded that overall funding levels have been quite static over that time frame. Since last year, pension funded status appears to have shifted marginally lower when looking at the distribution of funded status of all the companies, however, on an aggregate basis the funded status is virtually unchanged. Regulated utility companies, unlike industrial companies operating in the competitive marketplace, usually can collect pension expenses in rates. These expenses are included when a utility files a rate case. However, for companies operating under long-term rate freezes or for companies that do not plan to file rate cases in the near term, the inability to collect the appropriate amount of pension expense in rates may lead to diminished credit-protection measures. Also, some may make cash contributions to the pension fund assets. These contributions may divert cash flow intended for other purposes, necessitating borrowing to meet obligations the company had expected to be paid through operating cash flows.

Standard & Poor's financial adjustments for postretirement obligations are fully described in two articles, "Corporate Ratings Criteria--Postretirement Obligations," published Oct. 28, 2004, which was updated by, "CreditStats: Standard & Poor's Revises Statistical Practices," published May 15, 2006.

The analytical adjustments that we make are:

- Debt adjustment. We treat unfunded pension liabilities, health care obligations, and other deferred benefits as debt-like. To simplify this analysis, we net all benefit plan assets and liabilities, combining a company's overfunded plans with its underfunded plans. We use the fullest measure of the unfunded liability available, generally the projected benefit obligation for pensions. Finally, we factor in an income tax benefit, reducing the liability by a tax benefit calculated at the marginal tax rate.
- Equity adjustment. Standard & Poor's increases or reduces equity by the net amount that the funded status of postretirement obligations exceeds or falls below the amounts recorded on the balance sheet. This amount is also reduced for an income tax benefit, calculated at the marginal tax

rate.

- Operating results adjustment. Standard & Poor's only considers pension service cost in calculating operating income. In this adjustment, we remove all amounts related to interest, return on plan assets, actuarial gains and losses, past service costs, settlements, and curtailments, leaving only service costs. This change is not adjusted for income taxes.
- Interest expense adjustment. Pension interest expense, which is the increase in the present value of the pension liability related to the passage of time and the assumed discount rate, is essentially a financing cost and is reclassified as such. Interest expense is reduced, but not below zero, by the return on pension assets. This adjustment is calculated twice, first using the normalized (or expected) return on pension plan assets and second using the actual return on assets. The normalized calculation reduces volatility caused when actual returns on assets differ widely from year to year. This change is not adjusted for income taxes.
- Funds from operations (FFO) adjustment. FFO is defined as net income from operations plus depreciation and amortization, deferred income taxes, and other noncash items. Standard & Poor's makes an additional adjustment to FFO for pension contributions. FFO will include, on a tax-effected basis, the total of service and interest costs, reduced by the return on pension plan assets. Cash payments in excess of this amount are considered to be debt repayment, and cash payments below this amount are considered to be borrowings. This adjustment is also calculated twice, first using the normalized (or expected) return on pension plan assets and second using the actual return on assets.

In September 2004 and May 2005, Standard & Poor's published summaries of U.S. utility pension and other postretirement benefit obligations. The purpose of these articles was to highlight trends in funding status and to benchmark pension and postretirement benefit status and assumptions for regulated entities. The companies in the database are regulated distributors of electricity and/or natural gas, integrated electric and natural gas utilities, and diversified energy companies that focus on regulated electricity and gas operations. The database consists of diversified holding companies and stand-alone entities that are not part of a larger holding company, and includes 91 companies (see Appendix).

To determine which companies might have larger adjustments as a result of using pension adjusted ratios in published numbers, we calculated the total pension and other postretirement benefit shortfall as a percentage of total assets in 2005. The top 10 companies are displayed in table 1, while table 2 shows three key credit metrics on an unadjusted basis for these companies, together with these metrics adjusted for unfunded pension and postretirement obligations.

Table 1

Top 10 Pension Plus OPEB Shortfalls As A Percent Of Total Assets

	Funded status (mil. $)				
	Pension	OPEB	Total	Total assets (mil. $)	Total shortfall as a % of total assets
Central Hudson Gas & Electric Corp.	(60)	(88)	(148)	1,121	13.23
National Fuel Gas Co.	(209)	(275)	(483)	3,723	12.98
Madison Gas & Electric Co.	(57)	(46)	(103)	914	11.22
Central Vermont Public Service Corp.	(36)	(24)	(60)	551	10.9
ALLETE Inc.	(75)	(76)	(151)	1,399	10.82
KeySpan Corp.	(502)	(945)	(1,446)	13,813	10.47
El Paso Electric Co.	(81)	(88)	(169)	1,665	10.16
National Grid USA	(848)	(1,097)	(1,945)	20,712	9.39
WGL Holdings Inc.	1	(207)	(207)	2,446	8.46
Laclede Group Inc.	(54)	(39)	(93)	1,227	7.61

OPEB--Other postemployment benefits.

Table 2

Credit Measures Pre- And Post-Pension Adjustment

	Total debt to total capital (%)			FFO to total debt (%)			FFO to interest		
	Pre-pension adjs.	Pension adjusted	Difference	Pre-pension adjs.	Pension adjusted	Difference	Pre-pension adjs.	Pension adjusted	Difference
Central Hudson Gas &	56.2	68.0	11.8	17.1	13.1	(4.0)	4.5	3.8	(0.7)

Electric Corp.									
National Fuel Gas Co.	48.7	59.8	11.1	33.2	28.2	(5.0)	5.5	5.9	0.4
Madison Gas & Electric Co.	48.2	54.4	6.2	22.7	18.4	(4.3)	5.8	5.2	(0.6)
Central Vermont Public Service Corp.	65.9	70.5	4.6	6.6	6.3	(0.3)	2.1	1.8	(0.3)
ALLETE Inc	46.9	54.3	7.4	14.3	11.7	(2.6)	3.3	3.2	(0.1)
KeySpan Corp.	52.9	61.0	8.1	19.5	16.5	(3.0)	4.2	4.1	(0.1)
El Paso Electric Co.	53.2	57.7	4.5	29.3	26.0	(3.3)	5.8	5.8	0.0
National Grid USA	38.5	46.3	7.8	28.8	24.2	(4.6)	6.1	6.1	0.0
WGL Holdings, Inc.	43.4	52.4	9.0	28.8	25.7	(3.1)	5.4	5.6	0.2
Laclede Group Inc	56.9	67.3	10.4	14.1	14.8	0.7	3.3	3.3	0.0

As can be seen in table 1, eight of the top 10 companies are relatively small in terms of total assets. While their funding statuses in absolute dollars are not especially large, the size of the shortfall as compared with the size of the company is large. Indeed, as seen in table 2, Central Hudson Gas and National Fuel Gas each show debt to capital more than 11% higher after adjusting for pension and other postemployment employee benefits (OPEB) shortfalls. Central Hudson collects funds for its pension plan in rates. To the extent that pension expense and postretirement benefits increased to amounts beyond what is captured in rates, Central Hudson does not need to expense the undercollection. Instead, the difference between the actual amounts and those collected in rates is deferred in the form of a regulatory asset, based on the *anticipation that the difference will be collected in the future. From a credit perspective, the regulatory* deferral provides the utility with some assurance that costs incurred today and funded with operating cash flow will be recovered in the future along with any associated carrying costs.

As can be seen in table 2, the size of the adjustments is not directly related to the size of the shortfall as a percentage of total assets. This is because the adjustment is a function of not just the underfunded amount, but also of the portion of the underfunded amount that is already reflected on the balance sheet.

In addition, in some cases FFO/debt and FFO/interest actually improve on an adjusted basis. This is because the adjustment to FFO will be positive if cash payments to the plan are greater than the tax-affected total of service and interest costs, reduced by the return on pension plan assets. Of course, utilities do not always wait to collect the underfunded amounts. In the first quarter of 2005, Exelon Corp. entered into a $2 billion term loan agreement to fund pension contributions. In this case, the off-balance-sheet pension obligation was in fact converted to on-balance-sheet debt. Also, CenterPoint Energy used about $400 million of the proceeds of its sale of Texas Genco Holdings Inc. to fund pension contributions. This reduced the amount of debt reduction possible from the proceeds from that sale. The contribution also allowed CenterPoint to move from a substantially underfunded position to a virtually fully funded position. These are not the only examples, but clearly, underfunded pension obligations affected these companies' decisions as to how to allocate capital.

Although companies can fund pensions through rates, the funding of large shortfalls may not be palatable for regulators. Ultimately, the unfunded obligations will lead to higher rates or strained regulatory relations. If Standard & Poor's is not comfortable with the ultimate recoverability of a shortfall in rates, this will negatively affect the utility's business profile score. Meanwhile, if utilities have booked a regulatory asset, and Standard & Poor's is comfortable with the ultimate recoverability of that regulatory asset, it will positively affect the business profile score.

Aggregate Pension And OPEB Funding

A review of the 91 companies in the database concludes that there is no material deviation in the pension assumptions and pension and OPEB funded status over last year. The aggregate pension funding ratio, which is the fair value of the plan assets divided by the projected benefit obligation, increased marginally to 88.9% in 2005 from 88.5% in 2004. The chart displays the distribution of pension-funded status over the 91 companies. On an aggregate basis, there appears to be a shift toward less funded levels, with 13% overfunded in 2005 versus 14% in 2004, and 36% below 80% funded in 2005 versus 30% in 2004. Because the aggregate funding level is virtually unchanged, this would imply that larger companies may be improving their funded status, while more of the smaller companies are seeing their funded status fall. Exelon's large contribution is a case-in-point.

image

Individual Company Status

As previously discussed, regulated utility companies usually can collect pension expenses in rates. However, some may make cash contributions to the pension fund assets in excess of amounts collected through rates, necessitating borrowing to meet obligations the company had expected to be paid through operating cash flows. To highlight companies for which such shortfalls may become an issue, Standard & Poor's examined funding ratios, pension and total postretirement benefit shortfalls, and such shortfalls as a percentage of total debt.

While the aggregate pension funding ratio for the utility group was 88.9% in 2005, pension funding ratios range from 60% to 195%. Table 3 displays the top-five and bottom-five companies for pension funding ratios, respectively.

Table 3

Top Five And Bottom Five Pension Funding Ratios In 2005

	Plan assets (mil. $)	Projected benefit obligation (mil. $)	Ratio (%)
Five lowest funding ratios			
PacifiCorp	806.5	1,338.1	60.3
El Paso Electric Co	123.5	204.7	60.3
Cinergy Corp.*	1,169.0	1,898.0	61.6
CMS Energy Corp.	1,018.0	1,601.0	63.6
Black Hills Corp.	59.3	93.1	63.7
Five highest funding ratios			
FPL Group Inc.	3,120.0	1,599.0	195.1
Nicor Gas Co.	424.0	284.4	149.1
SCANA Corp.	854.3	711.5	120.1
Dominion Resources Inc.	4,360.0	3,834.0	113.7
Southern Co.	6,147.0	5,557.0	110.6

*Cinergy Corp. has completed its merger with Duke Energy Corp. and will not be part of this database on a stand-alone basis going forward.

More telling is the measurement of total shortfalls as compared with the companies' size as measured by total assets (discussed above and displayed in table 1). This measurement provides a benchmark for how large a relative off-balance-sheet obligation is represented by the pension and OPEB shortfall. For example, Black Hills Corp.'s pension-funding ratio is among the lowest at 63.7%. However, its pension shortfall represents only 1.6% of the company's total assets. The aggregate pension shortfall for the companies analyzed was $15.2 billion in 2005, as compared with $15.3 billion in 2004. The total pension and OPEB shortfall was $40.5 billion, as compared with $40.3 billion in 2004. Clearly, OPEB underfunding is substantially greater than pension underfunding. Interestingly, 37% of the pension shortfall comes from the companies with the five largest pension shortfalls, while only 26% of the total pension and OPEB shortfall comes from the companies with the five largest total pension and OPEB shortfalls.

Tables 4 and 5 display the companies with the highest liabilities. The Tennessee Valley Authority ranked first in the largest pension shortfall category while Exelon, which ranked first in 2004, improved due to its $2 billion cash contribution. However, when including both pension and OPEB funding, Exelon's shortfall remains the largest, and if its merger with Public Service Enterprise Group goes forward, the consolidated entity's shortfall will be quite large on an absolute basis. FirstEnergy Corp. has continuously improved its pension plus OPEB shortfall, which is down to $1.54 billion in 2005 from $1.76 billion in 2004 and $2.68 billion in 2003.

Table 4

Companies With The Largest Pension Shortfalls

	Pension shortfall (mil. $)

2005	
Tennessee Valley Authority	1,418
PG&E Corp.	1,200
Exelon Corp.	1,187
Entergy Corp.	899
National Grid USA	848
2004	
Exelon Corp.	2,761
Tennessee Valley Authority	1,338
PG&E Corp.	943
National Grid USA	776
Entergy Corp.	761

Table 5

Companies With The Largest Pension Plus OPEB Shortfalls

	Pension shortfall (mil. $)
2005	
Exelon Corp.	3,143
Tennessee Valley Authority	1,962
Public Service Enterprise Group	1,750
DTE Energy Co.	1,741
Entergy Corp.	1,683
2004	
Exelon Corp.	4,503
Tennessee Valley Authority	1,785
FirstEnergy Corp.	1,761
American Electric Power Co. Inc.	1,560
Public Service Enterprise Group	1,519

OPEB–Other postemployment employee benefits.

Appendix

Table 6

Companies In Pension Database

1	AGL Resources Inc.	50	National Grid USA
2	Allegheny Energy Inc.	51	Nicor Gas Co.
3	ALLETE Inc.	52	NISource Inc.
4	Alliant Energy Corp.	53	Northeast Utilities
5	Ameren Corp.	54	NorthWestern Corp.
6	American Electric Power Co. Inc.	55	Northwest Natural Gas Co.
7	Aquila Inc.	56	NSTAR
8	Atmos Energy Corp.	57	OGE Energy Corp.
9	Avista Corp.	58	ONEOK Inc.
10	Black Hills Corp.	59	PacifiCorp
11	Cascade Natural Gas Corp.	60	Pacific Gas & Electric Co.
12	CenterPoint Energy Inc.	61	Peoples Energy Corp.
13	Central Hudson Gas & Electric Corp.	62	PEPCO Holdings Inc.
14	Central Vermont Public Service Corp.	63	Piedmont Natural Gas Co. Inc.
15	Cinergy Corp.	64	Pinnacle West Capital Corp.
16	Cleco Corp.	65	Public Service Co. of New Mexico
17	CMS Energy Corp.	66	Portland General Electric Co.
18	Consolidated Edison Inc.	67	PPL Corp.
19	Constellation Energy Group Inc.	68	Progress Energy Inc.

20 Dominion Resources Inc.
21 Duquesne Light Holdings Inc.
22 DTE Energy Co.
23 DPL Inc.
24 Duke Energy Corp.
25 Dynegy Inc.
26 Edison International
27 El Paso Electric Co.
28 Empire District Electric Co.
29 Energen Corp.
30 Energy East Corp.
31 Entergy Corp.
32 Equitable Resources Inc.
33 Exelon Corp.
34 FirstEnergy Corp.
35 FPL Group Inc.
36 Great Plains Energy Inc.
37 Green Mountain Power Corp.
38 Hawaiian Electric Industries Inc.
39 IDACORP Inc.
40 IPALCO Enterprises Inc.
41 Kentucky Utilities Co.
42 KeySpan Corp.
43 Kinder Morgan Inc.
44 Laclede Group Inc.
45 Louisville Gas & Electric Co.
46 Madison Gas & Electric Co.
47 MDU Resources Group Inc.
48 MidAmerican Energy Holdings Co.
49 National Fuel Gas Co.
69 Public Service Enterprise Group Inc.
70 Puget Energy Inc.
71 Questar Corp.
72 SCANA Corp.
73 SEMCO Energy Inc.
74 Sempra Energy
75 Sierra Pacific Resources
76 South Jersey Gas Co.
77 Southern Co.
78 Southern Union Co.
79 Southwest Gas Corp.
80 TECO Energy Inc.
81 Tennessee Valley Authority
82 Texas-New Mexico Power Co.
83 Unisource Energy Corp.
84 TXU Corp.
85 Vectren Corp.
86 Westar Energy Inc.
87 WGL Holdings Inc.
88 Williams Cos. Inc. (The)
89 Wisconsin Energy Corp.
90 WPS Resources Corp.
91 Xcel Energy Inc.

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Note: Excerpt from the Deloitte publication titled, "Power & Utilities Sector 2006 Accounting, Financial Reporting, and Tax Update", page 29.
Copy of the complete publication can be obtained at the following website:
http://www.deloitte.com/dtt/article/0,1002,sid%253D2206%2526cid%253D140996,00.html

- The percentage increase in rates scheduled under the regulatory recovery plan for each future year should be no greater than the percentage increase in rates scheduled under the plan for each immediately preceding year (no 'backloading', similar to phase-in plans under SFAS 92). The EITF observed that straight-line recovery would meet this criterion.

Because the adoption date for SFAS 106 was for fiscal years beginning after December 15, 1992, the deferral period of approximately five years has ended and the recovery period should end around 2012.

The EITF also reached a consensus that a utility should disclose in its financial statements:

- A description of the regulatory treatment of OPEB costs.
- The status of any pending regulatory action.
- The amount of any SFAS 106 costs deferred as a regulatory asset at the balance sheet date
- The period over which the deferred amounts are expected to be recovered in rates.

SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements 87, 88, 106, and 132(R)*

SFAS 158 has many regulatory implications. Amounts otherwise charged/credited to AOCI upon application of SFAS 158 could/should be recorded as a regulatory asset or liability if the utility has historically recovered and currently recovers SFAS 87, *Employers' Accounting for Pensions*, pension expense and SFAS 106 OPEB expense in rates (the determination should be made on a plan by plan basis) and there is no negative evidence that the existing regulatory treatment will change.

We do not believe that a specific regulatory order is required to record the regulatory asset or liability in the absence of such negative evidence. The reasoning is that if the utility is currently recovering SFAS 87 and SFAS 106 expense in rates, the AOCI amounts ultimately will be amortized to SFAS 87 or SFAS 106 expense in subsequent years and thus recovered/refunded in future rates. However, if it is probable the utility will have a SFAS 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefits Pension Plans and for Termination Benefits*, curtailment/settlement and that the related costs typically would not be recoverable in rates, a regulatory asset should not be recorded without a specific regulatory order.

If the utility has not historically recovered SFAS 106 expense in rates, but is currently, no regulatory asset should be recorded until the cumulative rate recovery since the adoption of SFAS 106 equals or exceeds cumulative SFAS 106 expense since the adoption of SFAS 106.

If SFAS 87 expense is on pay-as-you-go or some other non-SFAS 87 method for rate purposes, but the company has previously established support for a regulatory asset or liability, that previous support would likely be sufficient to continue regulatory asset or liability treatment for pension AOCI amounts. If the company does not recover SFAS 87 expense in rates and cannot currently record a regulatory asset/liability for the difference in expense, it would need a specific regulatory order or change in rate treatment to now record regulatory assets/liabilities for the pension AOCI amounts.

As noted in the previous OPEB discussion, under EITF Issue 92-12 a regulatory asset related to SFAS 106 costs should not be recorded if the company's regulator continues to follow pay-as-you-go ratemaking treatment. EITF Issue 92-12 applies only to the accounting for regulatory assets related to SFAS 106 costs.

Electric Revenue Adjustment Mechanisms and Other Alternative Revenue Programs

The EITF reached a consensus in EITF Issue 92-7, *Accounting by Rate Regulated Utilities for the Effects of Certain Alternative Revenue Programs*, on accounting for the effects of certain alternative revenue programs. This consensus applies only to rate-regulated utilities under SFAS 71. The following discussion is an overview of this issue along with the consensus reached by the EITF.

Traditionally, regulated utilities, whose rates are based on cost of service, charge their customers by applying approved base rates to usage. Some regulators have also authorized the use of additional, alternative revenue programs. The major alternative revenue programs currently used are addressed in EITF Issue 92-7 and can generally be segregated into two types of programs:

- Programs that adjust billings for the effects of weather abnormalities or broad external factors, or that compensate the utility for demand-side management initiatives, which consists of various load management and conservation programs designed to address capacity, potential peak demand reductions and cost-saving opportunities for customers and environmental concerns; and
- Programs that provide for additional billings (incentive awards) if the utility achieves certain established performance measures, such as reducing costs, reaching specified milestones, or demonstratively improving customer service.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K
CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of Report: January 26, 2007

Exact Name of Registrant as Specified in Its Charter	Commission File Number	I.R.S. Employer Identification No.
Hawaiian Electric Industries, Inc.	1-8503	99-0208097
Hawaiian Electric Company, Inc.	1-4955	99-0040500

State of Hawaii
(State or other jurisdiction of incorporation)

900 Richards Street, Honolulu, Hawaii 96813
(Address of principal executive offices and zip code)

Registrant's telephone number, including area code:

(808) 543-5662 - Hawaiian Electric Industries, Inc. (HEI)
(808) 543-7771 - Hawaiian Electric Company, Inc. (HECO)

None
(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 5.03 Amendments to Articles of Incorporation or Bylaws; Change in Fiscal Year

The Board of HEI approved, at its meeting on January 30, 2007, an amendment to Article III (Board of Directors), Section 12 of the Bylaws of the Company, effective January 30, 2007, and the restatement of the Bylaws as thus amended. Prior to the amendment, Section 12 of the Bylaws provided that any action required or permitted to be taken at any meeting of the board of directors, or a committee of the board of directors, may be taken if all of the members of the board or committee, as the case may be, sign a written consent setting forth the action taken and the effective date of that action. The revision to Section 12 allows the members of the board or committee to provide their written consent via electronic transmission, provided the consent is submitted with information from which it may be determined that the electronic transmission was authorized by the proper board or committee members.

The Bylaws, amended and restated in their entirety to incorporate this amendment to Article III, Section 12, is included as an exhibit to this Current Report.

Item 8.01 Other Events.

The following is an update to the discussion in "Management's Discussion and Analysis of Financial Condition and Results of Operations" under "Most recent rate requests" and "Pension and other postretirement benefits," which are incorporated herein by reference to pages 49-52 and pages 40-42, respectively, of HEI's and HECO's Form 10-Q for the quarter ended September 30, 2006.

By application filed on December 8, 2005 (AOCI Docket), the electric utilities had requested the Public Utilities Commission of the State of Hawaii (PUC) to permit them to record, as a regulatory asset pursuant to Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," the amount that would otherwise be charged against stockholders' equity as a result of recording a minimum pension liability as prescribed by SFAS No. 87, "Employers' Accounting for Pensions." The electric utilities updated their application in the AOCI Docket in November 2006 to take into account SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)." The parties in the AOCI Docket include the electric utilities, the Consumer Advocate and the Department of Defense. The Consumer Advocate opposed the application, but the Department of Defense did not object to the requested relief on the understanding that the ratemaking treatment of the regulatory assets being requested by the electric utilities was not being addressed in the proceeding.

On January 26, 2007, the PUC issued a D&O in the updated AOCI docket, which denied the electric utilities' request to record a regulatory asset on the grounds that the electric utilities had not met their burden of proof to show that recording a regulatory asset was warranted, or that there would be adverse consequences if a regulatory asset was not recorded. The electric utilities are considering their options as a result of the decision. The PUC also required HECO to submit a pension study (determining whether ratepayers are better off with a well-funded pension plan, a minimally-funded pension plan, or something in between) by May 31, 2007 in its pending 2007 test year rate case, as proposed by the electric utilities in support of their request.

Although there is not an immediate impact on net income due to this D&O, the electric utilities are required to record substantial charges against stockholder's equity, and their reported returns on rate base and returns on average common equity will be higher (than if there were no charge against stockholder's equity). Consolidated debt to capitalization and interest coverage ratios of the Company and the electric utilities will deteriorate, which could result in security ratings downgrades and difficulty or greater expense in obtaining future financing. The electric utilities will continue to seek a return on their pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of related deferred income taxes) in rate base in their respective rate cases.

Forward-Looking Statements

This document may contain "forward-looking statements," which include statements that are predictive in nature, depend upon or refer to future events or conditions, and usually include words such as expects, anticipates, intends, plans, believes, predicts, estimates or similar expressions. In addition, any statements concerning future financial performance (including future revenues, expenses, earnings or losses or growth rates), on-going business strategies or prospects and possible future actions, which may be provided by management, are also forward-looking statements. Forward-looking statements are based on current expectations and projections about future events and are subject to risks, uncertainties and assumptions about HEI and its subsidiaries, the performance of the industries in which they do business and economic and market factors, among other things. These forward-looking statements are not guarantees of future performance.

Forward-looking statements in this document should be read in conjunction with the "Forward-Looking Statements" discussion (which is incorporated by reference herein) set forth on page iv of HEI's and HECO's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, and in HEI's and HECO's future periodic reports that discuss important factors that could cause HEI's and HECO's results to differ materially from those anticipated in such statements. Forward-looking statements speak only as of the date of this document.

Item 9.01 Financial Statements and Exhibits

Exhibit No.	Description
Exhibit 3(ii)	HEI's Amended and Restated By-Laws

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrants have duly caused this report to be signed on their behalf by the undersigned thereunto duly authorized. The signature of the undersigned companies shall be deemed to relate only to matters having reference to such companies and any subsidiaries thereof.

HAWAIIAN ELECTRIC INDUSTRIES, INC.
(Registrant)

/s/ Eric K. Yeaman
Eric K. Yeaman
Financial Vice President, Treasurer
and Chief Financial Officer
(Principal Financial Officer of HEI)
Date: February 5, 2007

HAWAIIAN ELECTRIC COMPANY, INC.
(Registrant)

/s/ Tayne S. Y. Sekimura
Tayne S. Y. Sekimura
Financial Vice President
(Principal Financial Officer of HECO)
Date: February 5, 2007

Maui Electric Company, Ltd.
Financial Ratios

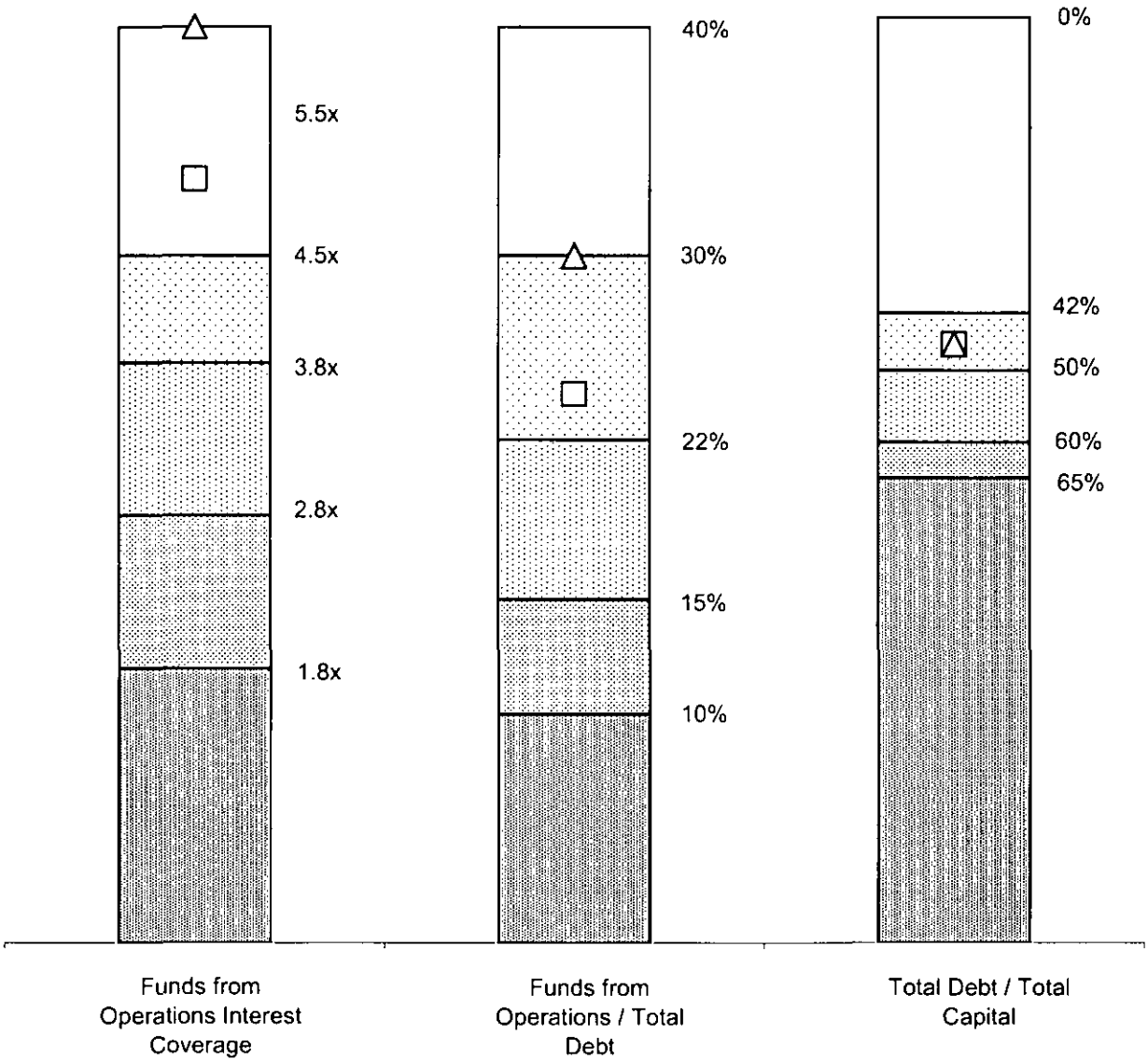
Test Year 2007	NO Rate Increase	WITH Rate Increase
Funds from Operations Interest Coverage *	5.00 x	6.03 x
Funds from Operations / Average Total Debt *	24%	30%
Total Debt / Total Capital *	47.3%	47.3%
Total Debt / Total Capital without Purchased Power Debt Equivalent	47.0%	47.0%

2005 Actual	
Total Debt / Total Capital *	44.0%
Total Debt / Total Capital without Purchased Power Debt Equivalent	43.6%

* These ratios take into account the debt equivalent (off-balance sheet purchased power and operating lease obligations).

Financial Ratios in Comparison to S&P Rating Guidelines

Business Profile = 5



MECO w/ Rate Increase	6.0 x	30%	47%
MECO w/out Rate Increase	5.0 x	24%	47%

- AA
- A
- BBB
- BB
- Below BB
- HECO with Rate Increase
- HECO without Rate Increase

Maui Electric Company, Ltd.
AOCI IF SFAS 158 HAD APPLIED SINCE 1995
1995-2006
($ in thousands)

Year	Contributions to Trust	NPPC Accrual	Ending Pension Asset Balance before AOCI Adj	PBO at 12/31	MV Plan Assets at 12/31	ILLUSTRATION ONLY Asset (Liability) under SFAS 158	AOCI (net of tax)
	A	B	C= Prior C + A - B	D	E	F = E - D	G
1994			(7)				
1995	1,441	1,461	(27)	52,144	51,570	(574)	(334)
1996	1,970	2,009	(66)	55,680	58,699	3,019	1,885
1997	1,755	1,765	(76)	59,257	67,628	8,371	5,160
1998	95	952	(933)	66,312	76,617	10,305	6,865
1999	0	591	(1,524)	57,359	95,774	38,415	24,399
2000	0	(2,266)	742	64,098	89,980	25,882	15,358
2001	0	(2,279)	3,021	69,406	77,848	8,442	3,312
2002	0	(1,496)	4,517	79,319	63,730	(15,589)	(12,283)
2003	3,223	2,127	5,613	91,364	77,824	(13,540)	(11,701)
2004	4,581	1,016	9,178	100,029	86,471	(13,558)	(13,889)
2005	1,000	1,745	8,433	108,437	89,693	(18,744)	(16,602)
2006	0	3,210	5,223	110,794	96,406	(14,388)	(11,980)
Total	$ 14,065	$ 8,835					

Effective composite income tax rate 38.91%

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

DOCKET NO. 2006-0387
APPLICATION OF MAUI ELECTRIC COMPANY, LIMITED
FOR APPROVAL OF RATE INCREASES AND
REVISED RATE SCHEDULES AND RULES

AFFIDAVIT OF WILLIAM E. AVERA, PH.D., CFA

STATE OF TEXAS)
)
COUNTY OF TRAVIS)

Before me, the Undersigned Authority, on this 15th day of February 2007, personally appeared William E. Avera, upon being duly sworn, states the following:

My name is William E. Avera. I am over the age of 21, of sound mind and competent to testify to the matters stated herein. I am a principal in Financial Concepts and Applications, Inc. (FINCAP), a consulting firm engaged in financial, economic, and policy consulting to business and government. My business address is 3907 Red River, Austin, Texas 78751. A resume containing the details of my qualifications is attached as Appendix A.

1. In December 1996, the Public Utilities Commission of the State of Hawaii (PUC) concluded an examination of the relationship between Hawaiian Electric Industries, Inc. (HEI) and Hawaiian Electric Company, Inc. (HECO), including HECO's two electric utility subsidiaries, Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO). At that time, the PUC stated its intention to evaluate the need for a comprehensive analysis of the impact that HEI's diversified activities have on the cost of capital to HECO and its subsidiaries on a case-by-case basis in future rate proceedings. The purpose of this affidavit is to evaluate any circumstances which might alter the conclusions adopted by the PUC in its last investigation or justify including a detailed review of this issue in the scope of MECO's current rate proceeding. I previously conducted similar reviews in conjunction with affidavits submitted in Docket No.

97-0346 (December 1997) on behalf of MECO, Docket Nos. 97-0420 (March 1998), 99-0207 (October 1999 and June 2000), and 05-0315 (May 2006) on behalf of HELCO, and Docket Nos. 04-0113 (November 2004) and 2006-0386 (December 2006) on behalf of HECO.

2. Based on my evaluation, I found no evidence that would modify the findings resulting from the PUC's last review of the relationship between HEI and HECO or justify a comprehensive reexamination of these issues in MECO's present rate case, especially in light of the additional complexities and costs such a study would introduce.

3. By an order dated January 26, 1993, the PUC initiated Docket No. 7591 to review the relationship between HEI and HECO. The purpose of the review was to determine whether HEI's diversified activities, management policies, operations, or business practices resulted in any negative effects on HECO, HELCO, MECO, or ratepayers. Dennis Thomas and Associates was retained by the PUC to perform the review. An examination of the effect of diversification on the cost and availability of capital to HECO was included in the scope of the investigation, with a report (Thomas Report) being issued in January 1995.

4. I was retained by Dennis Thomas and Associates and served as Team Leader, Financial Integrity and Credit Ratings. In this position, I held direct responsibility for evaluating the impact of diversification on the availability and cost of capital for HECO and its electric utility subsidiaries, with my conclusion being incorporated into the Thomas Report.

5. The Thomas Report concluded that "on balance, diversification has not hurt electric ratepayers." With respect to the availability and cost of capital to HECO, the Thomas Report found that HECO's access to capital did not suffer as a result of HEI's involvement in non-utility activities and that diversification did not permanently raise or lower the cost of capital incorporated into the rates paid by HECO's utility customers. The Thomas Report was adopted by the PUC in its entirety in December 1996. Additionally, the PUC stated that it would apply the recommendation of the Department of Defense that the utility present a comprehensive analysis of the impact of HEI on the cost of capital for the utilities on a "case-by-case" basis in the utilities' respective rate cases.

6. In assessing the likelihood that changes in circumstances might alter the conclusions of the Thomas Report, my evaluation focused primarily on events since the report was issued in January 1995, with particular emphasis on developments since my last review was completed in Docket No. 2006-0386. The availability and cost of capital is a function of investors' expectations and requirements as reflected in the capital markets. In order to examine the ongoing impact of HEI's non-utility businesses on HECO's cost and availability of capital, I reviewed numerous reports of leading investment advisory services as a guide to investors' perceptions and requirements.

7. Bond ratings, and the analyses prepared by the major rating agencies, are frequently referenced by investors and provide a useful benchmark for the risks perceived in the capital markets. As I noted in my initial affidavit filed in Docket No. 99-0207, the bond ratings assigned to HECO's first mortgage bonds by the major rating agencies were unchanged from the time the Thomas Report was prepared until these securities were redeemed in December 1, 1997.

8. Events over the last decade caused investors to rethink their assessment of the relative risks associated with the electric power industry. A well-publicized energy crisis throughout the West wreaked havoc on customers, utilities, and policymakers and had dramatic repercussions for investors and utilities nationwide. The collapse of Enron and others engaged in merchant generation and energy trading and marketing increased turmoil within the industry and served to further magnify the risks associated with the power sector. Investor confidence in the electric power industry was severely shaken, leading to reduced access to capital and constrained liquidity for many utilities.

9. While the severe distortions that characterized the energy crisis of 2000-2001 have faded, investors recognize that the continuing prospect for price spikes in energy markets cannot be discounted. Apart from continued variability in wholesale power markets, in recent years utilities and their customers have also had to contend with dramatic fluctuations in fuel costs due to ongoing volatility in the spot markets. S&P noted the danger posed by "high and volatile" fuel prices, which increase the uncertainties associated with power supply costs.[1] More recently, Fitch concluded, "Historically high and volatile commodity prices will continue to affect nearly the entire power and gas sector."[2] In addition, policy evolution in the electric transmission segment has been wide-reaching for mainland utilities, and investors have increasingly focused on uncertainty over operating rules and market development.

10. Revised perceptions of the risks in the industry and weakened utility finances combined to produce steady erosion in credit quality throughout the electric utility industry. For example, during 2002 Standard & Poor's Corporation (S&P) recorded 182 downgrades in the electric power industry, versus only fifteen upgrades,[3] while downgrades outpaced upgrades by more than fifteen-to-one in the fourth quarter of 2003.[4] While the pace and scale of credit ratings actions has

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[1] Standard & Poor's Corporation, "Prolonged High Natural Gas Prices May Increase Credit Risk for U.S. Gas Distributors," *RatingsDirect* (Jan. 19, 2005)
[2] Fitch Ratings, Ltd., "U.S. Power and Gas 2007 Outlook," *Global Power North American Special Report* (Dec. 15, 2006) at 1.
[3] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15, 2003).
[4] Standard & Poor's Corporation, "U.S. Utilities' Ratings Decline Continued in 2003, But Pace Slows," *RatingsDirect* (Feb. 2, 2004).

since stabilized, the majority of companies in the utility sector now fall in the tripleB rating category, with a continued negative bias in the credit outlook for the sector.[5]

11. Although these developments focused increased attention on the potential impact of non-utility businesses on investment risk, in the immediate aftermath of the Western energy crisis, the investment community was primarily concerned with merchant generation and energy trading activities, particularly where high debt leverage was employed. For example, S&P noted that the deterioration in the utility industry's credit quality could be traced in part to:

> Heightened business risk derived from growing, debt-financed investments ... mainly in unregulated generation and energy trading and marketing activities, that have continued to severely underperform expectations.[6]

In June 2002, S&P noted that "the last 24 months have witnessed extraordinary turmoil for power and energy debt," attributing this unprecedented shift in risk perceptions to "the credit collapse of the California utilities, through the Enron bankruptcy and subsequent market disruptions for U.S. energy merchant companies."[7]

12. Since that time, many utilities have pursued a "back to basics" strategy that has emphasized the sale of non-regulated business lines, particularly energy trading and marketing, and refocused attention on regulated electric and gas utility operations. While this has generally been viewed as an effective course to reduce overall uncertainties, the investment community has increasingly recognized that regulated operations convey their own set of challenges. For example, S&P cautioned that:

> Much of the industry continues to re-emphasize core competencies, where risks are certainly more familiar, but still daunting. These include major pending regulatory decisions, the need for substantial infrastructure expenditures, fuel-cost recovery in a high-fuel-price environment, and still low, but gradually rising interest rates. In addition, event risk, specifically mergers and acquisitions, is a significant development with the repeal of the Public Utility Holding Company Act.[8]

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[5] Standard & Poor's Corporation, "Industry Report Card: Few Rating Actions For U.S. Electric, Gas, And Water Utilities In Third Quarter," *RatingsDirect* (Oct. 25, 2006).
[6] Standard & Poor's Corporation, "U.S. Power Industry Experiences Precipitous Credit Decline In 2002; Negative Slope Likely to Continue," *RatingsDirect* (Jan. 15. 2003).
[7] Standard & Poor's Corporation, *2002 Power & Energy Credit Conference: Beyond the Crisis* (June 12, 2002).
[8] Standard & Poor's Corporation, "First-Quarter U.S. Utility Upgrades Outpaced Downgrades, But Momentum Is Likely To Change," *RatingsDirect* (Apr. 27, 2006).

13. In contrast to the declining credit trend experienced by the industry as a whole, the corporate credit ratings of HEI and HECO have remained stable. This relatively greater financial strength can be attributed in part to the fact that HECO and its subsidiaries have not faced the uncertainties posed by industry restructuring and volatility in wholesale power markets. In addition, effective September 30, 2001, HEI announced that it was discontinuing its international power business and stated its intention to wind down HEI Power Corp. and dispose of its assets, with the goal of refocusing attention on its core Hawaii operations.

In response to HEI's decision to discontinue its international power operations, S&P raised HEI's business profile ranking, reflecting lower consolidated business risk, and commented that:

> Given the absence of the very risky nonregulated generation operations and HEI's concentration on the regulated utility (about 70% of earnings) and banking (30%) activities, the company's business profile is now characterized as average versus below average. The stronger business profile requires less stringent financial parameters.[9]

Similarly, Moody's noted that HEI's credit profile "benefited from the company's decision to reduce its overseas exposure" and concluded that renewed focus on core utility and banking operations has the effect of "significantly lowering its risk profile."[10]

14. The investment community has also distinguished between the tumultuous events that have traumatized diversified companies in the power sector and HEI's strategy of refocusing on its Hawaii utility and banking operations. As The Value Line Investment Survey (Value Line) concluded, for example:

> The unfavorable outcomes of regulatory restructuring and the severe slump in energy trading and marketing have hurt many companies in this sector, but not HEI.[11]

Thus, while the crisis of recent years motivated power industry participants to adopt a "back-to-basics" business strategy, investors recognized that HEI had already refocused its operations by discontinuing its international power business and exiting maritime and real estate operations. At the same time, the capital markets have distinguished between HEI's American Savings Bank (ASB) subsidiary, which is regarded as a core business, and the unregulated merchant power and energy trading activities that have commanded investor scrutiny.

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[9] Standard & Poor's Corporation, "Bulletin: Hawaiian Electric Industries Exits Nonregulated Generation," *RatingsDirect* (Nov. 1, 2001).
[10] Moody's Investors Service, "Opinion Update: Hawaiian Electric Industries, Inc.," *Global Credit Research* (Sep. 11, 2003).
[11] The Value Line Investment Survey (Nov. 15, 2002).

15. Investors generally perceive that ASB implies a level of business risk that exceeds that of HEI's regulated utility operations, but also recognize that HECO's investors and ratepayers are protected from these uncertainties. For example, while granting HEI's support of "riskier financial service operations," S&P noted that structural and regulatory protections afforded HECO warranted a higher bond rating than the parent:

> In most circumstances, Standard & Poor's will not rate the debt of a wholly owned subsidiary higher than the rating of the parent. However, exceptions can be made on the basis of structural protections or regulatory insulation, or both, assuming the entity has a financial profile that supports a higher rating. In Hawaiian Electric's case, in Standard & Poor's opinion, there are adequate insulating conditions in Hawaii's statutory and regulatory framework, including orders issued by the PUC regarding the formation of HEI's holding company structure, to separate the corporate credit ratings on HEI and Hawaiian Electric by one notch.[12]

Consistent with this view, S&P also made clear that it "does not accord any credit uplift to American Savings Bank as a result of its affiliation with HEI."[13]

16. The investment community continues to evaluate HEI as a member of the utility sector. In 2002, for example, Value Line concluded that HEI stock "is suitable for traditional, income-oriented utility investors.[14] Value Line continues to include HEI within its Electric Utility (West) industry group,[15] and Robert W. Baird & Company recently affirmed that HEI is a "core utility holding."[16] Meanwhile, S&P indicated that its April 2005 decision to revise its ratings outlook for HEI and HECO from "stable" to "negative" was motivated primarily by subpar protection parameters related to regulated utility operations.[17] S&P cited financial pressures stemming from a long-term lack of rate relief, rising operating expenses, and yet to be recovered investments. At the same time, S&P has repeatedly recognized the benefit of "decent earnings" attributable to ASB's "steady banking operations."[18]

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[12] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Mar. 16, 2006).
[13] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Nov. 22, 2006).
[14] The Value Line Investment Survey (Feb. 15, 2002, Aug. 16, 2002).
[15] See, *e.g.*, The Value Line Investment Survey (Feb. 9, 2007).
[16] Parker, David, "HE: Earthquake Damage Minimal; Maintain Estimates and Outperform," Robert W. Baird & Company (Oct. 17, 2006).
[17] Standard & Poor's Corporation, "Research Update: Hawaiian Electric Industries And Utility Units Ratings Affirmed; Outlook Revised To Negative," *RatingsDirect* (Apr. 22, 2005).
[18] See *e.g.*, Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Nov. 22, 2006).

17. ASB's strategic decision to expand its commercial lending business has not generated concern from bond ratings agencies or investors, and has generally been characterized as a gradual shift in emphasis rather than a dramatic departure from past strategy. Since 2000, the percentage of ASB's loan portfolio attributable to residential mortgages has declined from 83% to 73%, while commercial lending now represents 20% of total loans outstanding. S&P, for example, noted ASB's strategy of "slowly and conservatively" expanding its business banking and commercial real estate operations, while retaining the lower-risk profile of a more traditional thrift,[19] and S&P continues to evaluate ASB as part of the thrift sector.[20] As well, the investment community has recognized that ASB's strategy of broadening its lending into commercial loans has helped to support earnings in the face of a flattening yield curve.[21]

The conclusion that ASB's transformation from a traditional retail thrift to a full-service community bank has had no significant impact on investors' overall risk perceptions is also supported by reference to S&P's business profile ranking for HEI, which has remained stable at "6".[22] A risk profile ranking of "6" falls one notch above the midpoint of S&P's 10-point scale, which ranges from "1" (lowest risk) to "10" (highest risk).

18. While granting that banking activities involve an increment of business risk above that of regulated utility operations, the investment community also recognizes that HEI benefits through the diversification and financial support provided by these activities and generally perceives these operations as relatively conservative and stable. For example, S&P observed that:

> [O]ngoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows. The decrease in Hawaiian Electric's dividend to HEI is expected to be partly offset by the increase in the bank's dividend.[23]

In addition, S&P cited ASB's "solid earnings" from its "strong deposit funding base"[24] and its low-risk asset portfolio."[25] Similarly, Moody's Investors Service noted the stability of ASB's operations and the benefits of its predictable earnings

[19] Standard & Poor's Corporation, "Hawaiian Electric Industries Inc.," *RatingsDirect* (Mar. 28, 2003).
[20] Standard & Poor's Corporation, "Industry Report Card: U.S. Thrift Institutions Have Flat Second Quarter," *RatingsDirect* (Aug. 14, 2006).
[21] Fleishman, Steve and Kania, Alex, "Managing through the flat yield curve; still expensive," Merrill Lynch (May 15, 2006).
[22] Standard & Poor's Corporation, "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," *RatingsDirect* (Jun. 2, 2004); Standard & Poor's Corporation, "Issuer Ranking: U.S. Utility And Power Companies, Strongest To Weakest," *RatingsDirect* (Jan. 5, 2007).
[23] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Nov. 22, 2006).
[24] Standard & Poor's Corporation, "Industry Report Card: U.S. Thrift Institutions Have Flat Second Quarter," *RatingsDirect* (Aug. 14, 2006).
[25] Standard & Poor's Corporation, "Hawaiian Electric Company, Inc.," *RatingsDirect* (Aug. 30, 2006).

stream.[26] Other analysts have recognized that, despite the challenges posed by the current interest rate environment, ASB has continued to maintain margins and the high quality of its loan portfolio.[27] The investment community has also concluded that core utility and banking operations offer diversification that may insulate HEI's investors from the impact of changing interest rates.[28]

19. The investment community continues to focus on HEI's exposure to potential weakness in Hawaii's economy; however, there is no indication that this risk exposure has been significantly magnified by non-utility operations. For example, while the aftermath of the September 11, 2001 terrorist attacks resulted in an economic slowdown due to decreased tourism, investors made no distinction between HEI's core regulated utility and banking operations in their assessment of the effects of the downturn.

20. While the investment community has recently expressed some concern regarding higher debt levels in HECO's capital structure and deterioration in other financial measures, these developments have been attributed strictly to the challenges faced by HEI's regulated utility operations. For example, S&P noted that "HEI's consolidated financial condition remains somewhat weak for the rating despite the strong Hawaiian economy and the company's efforts in recent years to strengthen its capital structure."[29] S&P concluded that:

> Financial metrics have been pressured owing to rising operating and maintenance expenses, increasing capital outlays, the prolonged lack of rate relief, and recently, lower electricity sales caused by cooler less humid weather and customer conservation. Absent a responsive final rate order in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.[30]

Meanwhile, S&P reported that in the third-quarter of 2006 ASB began to pay nearly all of its earnings as dividends to HEI, while sustaining its target core capital ratio and supporting its own business needs.[31]

21. The methodology used to establish the allowed rate of return for HECO and its electric utility subsidiaries avoids any bias that might be introduced by the

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[26] Moody's Investors Service, "Liquidity Risk Assessment: Hawaiian Electric Industries, Inc.," *Global Credit Research* (Dec. 19, 2006); "Credit Opinion: Hawaiian Electric Industries, Inc.," (Dec. 21, 2006).
[27] See *e.g.*, Parker, David E., "HE: Increasing Costs and Inverted Yield Curve Pressures EPS" Robert W. Baird & Co. (Nov. 2, 2006); Arnold, Jonathan and Kania, Alex, "Still facing cost headwinds," Merrill Lynch (Dec. 11, 2006).
[28] See, *e.g.*, Fleichman, Steve, "Hawaiian Electric Industries Inc.," *Comment*, Merrill Lynch (Jul. 28, 2005). Moody's also noted that "HEI has two different business units to generate revenues, income, and cash flow." Moody's Investors Service, "Credit Opinion: Hawaiian Electric Industries, Inc.," (Dec. 21, 2006).
[29] Standard & Poor's Corporation, "Summary: Hawaiian Electric Company, Inc.," *RatingsDirect* (Nov. 22, 2006).
[30] *Id.*
[31] *Id.*

specific risks of HEI's diversified activities. This is because the cost of equity has consistently been established by reference to groups composed of other comparable utilities. The Thomas Report noted that this insulates ratepayers from the impact of diversified activities because "any changes to HEI's cost of equity in the past have not been reflected in the revenue requirements used to set HECO's rates."[32]

This approach has been consistently followed in prior proceedings, including MECO's last rate case in Docket No. 97-0346, and it is my understanding that this approach will also be followed in MECO's current rate case.

22. In conclusion, my review revealed no evidence that would alter the conclusions reached in the Thomas Report or indicate a fundamental change in investors' perceptions of the relationship between HEI and HECO. The comprehensive analyses conducted in preparing the Thomas Report required almost an entire year to complete and involved an exhaustive review of documents and extensive interviews with members of the investment community in Hawaii, on Wall Street, and in other financial centers. Given that the findings of such a comprehensive review with respect to the availability and cost of capital to HEI and its utility subsidiaries would not be expected to be materially different from those adopted by the PUC in December 1996, it is my opinion that the significant expenditure of time and money involved in conducting such a comprehensive review is not presently warranted.

Further Affiant sayeth not.

William E. Avera

Sworn and Subscribed before me this 15th day of February 2007:

Notary Public in and for
the State of Texas

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp. Jan. 10, 2011

[32] Thomas Report at 131.

APPENDIX A

QUALIFICATIONS OF WILLIAM E. AVERA

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

3907 Red River
Austin, Texas 78751
(512) 458–4644
FAX (512) 458–4768
fincap@texas.net

Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (over 150 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics in evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 200 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Hawaii, Idaho, Illinois, Indiana, Kansas, Maryland, Michigan, Missouri, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, and Wisconsin.

Testified in 40 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (75 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Operator of AAA Ranch, a certified organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas; A*ppointed by

Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board Member, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering Support Unit; Officer-in-charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success*, Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

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Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"The Who, What, When, How, and Why of Ethics", San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia, Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

"Electric Rate Design in Texas," Southwestern Economics Association, Fort Worth (Mar. 1979)

"Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Multi-period Wealth Distributions and Portfolio Theory," Southern Finance Association, Houston (Nov. 1973)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

SAVINGS FROM REVENUE BONDS

The calculation of the estimated savings from financing with tax-exempt special purpose revenue bonds ("revenue bonds") instead of financing with "equivalent" taxable debt[1] is shown on the last page of this exhibit. A total savings of about $47 million is estimated for MECO's customers over the "original" life[2] of each of the revenue bonds that are currently outstanding. The savings calculation, which is required by Hawaii law[3], is similar to the calculations in Docket Nos. 2006-0386 (HECO 2007 Test Year), 04-0113 (HECO 2005 Test Year), 05-0315 (HELCO 2006 Test Year), and 97-0346 (MECO 1999 Test Year) in that it takes into account the economic differences between selling revenue bonds and equivalent taxable debt: interest costs, taxes, issuance costs (including any redemption costs), issuance discounts, revenue bond investment differentials, trustee fees, and deferred taxes.

Assumptions

In doing the calculation, we try to capture the material factors which affect the estimated savings. The estimated savings are based on assumptions regarding interest rates at the time of issuance and in the future over the life of the issuance. For example, we must make informed assumptions of interest rates and issuance costs of taxable debt since we didn't actually issue the taxable bonds and therefore, don't know what their costs would have been with any certainty. We also make assumptions for factors that are dependent on future conditions which can't be known with certainty, now. For example, we don't know for sure that a series of revenue bonds will be outstanding for its entire life, but for calculating savings, we assume they will be. As

[1] Taxable debt with similar characteristics such as maturity date and call provisions.
[2] The life of a bond, assuming the bond remains outstanding until its original maturity date.
[3] Hawaii Revised Statutes Section 39A-208(b) and enabling legislation such as Act 206, 1998 Session Laws of Hawaii (Section 3).

another example, there are deferred tax effects that offset some of the savings, but the cost of the deferred tax difference depends on the rate of return on rate base in each year. We must make assumptions of the rate of return over the life of each series of revenue bonds in order to estimate the cost of the deferred tax difference.

Total Savings Versus Annual Savings

Estimated savings change from year to year over the life of a bond issue, mostly because of the impact of deferred taxes. Therefore, we have chosen to show total savings over the life of the bonds instead of savings on an annual basis.

Interest Costs

Revenue bonds have a lower interest cost than taxable debt with similar characteristics. The interest earned by buyers of revenue bonds is not taxable income for Federal or State of Hawaii income tax purposes (with some limited exceptions). This means that the revenue bonds can bear a lower interest rate than other forms of debt, and the owners of the bonds will still get the same after-tax return.

Column (D) of the savings calculation shows the revenue requirements of interest costs over the original lives of MECO's revenue bonds that are currently outstanding. It also shows the revenue requirements of estimated interest costs of equivalent taxable debt.

Amortized Costs and Trustee Fees

Issuance Costs: Revenue bonds currently have lower issuance costs than equivalent taxable debt, primarily because of the difference in underwriting fees and/or insurance costs. These fees are charged by underwriters for their work in carrying out marketing efforts for a bond sale and for taking the risk (with some exceptions) that they will be unable to resell the bonds without incurring a loss.

Issuance Discounts: Some revenue bonds were sold at a discount to secure a lower annual interest rate and reduce the overall cost of the bonds. These discounts are included in the total cost of revenue bonds. For taxable debt, we used interest rate estimates from underwriters based on issuances at par (that is, no discount). According to Goldman Sachs (the lead underwriter that we used for the most recent revenue bonds sold), taxable debt is commonly sold at par or with a small discount.

"Ongoing" Trustee Fees: Ongoing trustee fees consist of recurring annual fees from a bond trustee over the life of the bonds. Basically, bond trustees serve to protect the collective interest of the bondholders. As part of its duties, a bond trustee receives interest, principal, and redemption payments (if any) from the Companies and disburses them to bondholders. Ongoing trustee fees for revenue bonds are typically at about the same level as fees for equivalent taxable debt.

Construction Fund Trustee Fees: For revenue bond financings (except refunding issues), there are fees from construction fund trustees for managing the investment of undrawn revenue bond proceeds in the construction fund. These fees are generally expensed.

Column (E) of the savings calculation shows the total revenue requirements of issuance costs, redemption costs, issuance discounts, investment differentials, and trustee fees over the original lives of MECO's revenue bonds that are currently outstanding. It also shows the revenue requirements of estimated comparable costs of equivalent taxable debt.

Accumulated Deferred Taxes

Accumulated deferred tax balances reduce the Company's rate base. When assets are financed with revenue bonds, accumulated deferred tax balances are generally not as large as they would be if the assets were financed with other forms of debt. This is because assets financed

with revenue bonds must be depreciated more slowly for tax purposes than if they had been financed with taxable debt. Thus, when assets are financed with revenue bonds, the result is that our tax depreciation is closer to our book depreciation, deferred taxes are less, and the rate base is higher than would be the case if those assets were financed with other types of debt. This increases revenue requirements somewhat, but for the revenue bonds MECO has issued, the deferred tax impact does not offset all of the savings from the interest rate reduction.

Column (F) of the savings calculation shows the revenue requirement effect of the average accumulated deferred tax balances of the assets estimated to be financed with revenue bonds. It also shows the same calculation assuming the assets were financed with equivalent taxable debt.

Conclusion

Clearly, some of the interest cost savings from revenue bonds are offset by other economic factors. However, it has been to the benefit of the Company's customers that revenue bonds finance part of the Company's construction program.

Maui Electric Company, Ltd.

Estimated Savings Due to Special Purpose Revenue Bond Financing
($ in Thousands)

	(A)	(B)	(C)	(D) = [(A)*(B)/(1-R)]*C	(E)	(F)	(G) = (D)+(E)+(F)
				Revenue Requirements Over Original Life of Security *			
Series **	Interest Rate	Outstanding as of 12/31/05	Original Life (in years)	Interest	Amortized Costs and Trustee Fees	Average Accumulated Deferred Taxes	Total
Costs of Financing with TAXABLE DEBT:							
Series 1993	7.30%	$ 30,000	30	$ 72,107	$ 403	$ (9,988)	$ 62,523
Series 1996A	8.40%	20,000	30	55,315	293	(6,658)	48,949
Series 1996B	7.75%	35,000	30	89,310	576	(11,652)	78,234
Series 1997A	7.76%	20,000	30	51,100	240	(7,016)	44,324
Refunding Series 1998A (1987)	6.75%	7,720	14	8,007	114	(1,604)	6,517
Refunding Series 1999B (1988)	7.40%	9,000	19	13,888	262	(154)	13,996
Refunding Series 1999D (1990A)	7.80%	1,000	20	1,712	33	(18)	1,727
Refunding Series 2000 (1990B&C)	7.75%	20,000	20	34,023	592	(359)	34,256
Refunding Series 2005A (1995A)	5.25%	2,000	20	2,305	132	(36)	2,401
		$ 144,720		$ 327,766	$ 2,645	$ (37,485)	**$ 292,927** (H)
Costs of Financing with REVENUE BONDS:							
Series 1993	5.45%	$ 30,000	30	$ 53,833	$ 889	$ (789)	$ 53,933
Series 1996A	6.20%	20,000	30	40,828	1,121	(526)	41,423
Series 1996B	5 7/8%	35,000	30	67,703	1,729	(920)	68,511
Series 1997A	5.65%	20,000	30	37,206	759	(554)	37,411
Refunding Series 1998A (1987)	4.95%	7,720	14	5,872	181	(1,604)	4,449
Refunding Series 1999B (1988)	5.75%	9,000	19	10,791	376	(154)	11,013
Refunding Series 1999D (1990A)	6.15%	1,000	20	1,350	33	(18)	1,365
Refunding Series 2000 (1990B&C)	5.70%	20,000	20	25,023	647	(359)	25,311
Refunding Series 2005A (1995A)	4.80%	2,000	20	2,107	103	(36)	2,174
		$ 144,720		$ 244,713	$ 5,837	$ (4,959)	**$ 245,591** (I)
Estimated Savings to Customers (over original life of revenue bonds) = (H)-(I)							**$ 47,336**

* Revenue requirements = nontaxable expenses grossed up for revenue taxes (R), and taxable expenses grossed up for revenue taxes and income taxes. Refer to WP-1721, p.1 and p.4 for Amortized Costs/Trustee Fees and Average Accumulated Deferred Taxes calculations, respectively, for Series 1993, 1996A, and 1996B. Revenue Requirements information for other Series are contained in the "Estimated Savings From Special Purpose Revenue Bond Financing" document filed with the Commission for the respective Series.

** See reports on savings on file with the Commission.

Note: Totals may not add exactly due to rounding.

MECO T-18
DOCKET NO. 2006-0387

TESTIMONY OF
PETER C. YOUNG

DIRECTOR, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Cost-of-Service Study and Rate Design

INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young, and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii, 96813.

Q. What is your present position with the Company?

A. I am the Director of the Pricing Division of the Energy Services Department at the Hawaiian Electric Company, Inc. My experience and educational background are listed in MECO-300.

Q. Have you testified before the Commission in prior Company proceedings?

A. Yes. I have appeared as the Company's witness on test-year revenues, rate design, and cost-of-service studies in prior rate proceedings listed in MECO-300.

Q. What is your area responsibility in this proceeding?

A. My testimony will discuss the Maui Electric Company, Ltd. (MECO) cost-of-service studies, proposed rates, and proposed changes to the Company's rules. I also sponsor the testimony in MECO T-3.

COST-OF-SERVICE STUDIES

Q. What is a cost-of-service study?

A. A cost-of-service study is a tool used to determine the cost responsibility of the different rate classes served by MECO for ratemaking purposes. Two types of cost studies were prepared for this proceeding, one based on embedded or accounting costs, and the other is based on marginal costs. Although both studies reflect the costs of providing service, the procedure and emphasis of each of these two studies are different.

Q. What is the difference between an Embedded Cost-of-Service Study and a

Marginal Cost Study?

A. An Embedded Cost-of-Service Study, or simply referred to as cost-of-service study, is a process used to categorize and allocate the total utility costs of providing service (the utility's total revenue requirements) to the various rate classes in order to determine each class's costs responsibility. In contrast, a Marginal Cost Study determines the change in the utility's costs of providing service due to a unit change in kilowatts (kW), kilowatthours (kWh), or number of customers served by the utility.

RESULTS OF THE EMBEDDED COST-OF-SERVICE STUDY

Q. What costs are included in the cost-of-service study?

A. The cost-of-service study is based on the embedded or accounting costs, and includes all the costs incurred in providing electric service to customers. It includes the test-year estimates of operation and maintenance expenses, depreciation expenses, taxes, plant costs, and return on capital.

Q. How are the results of the cost-of-service study presented?

A. The summary exhibits separately compare the results at present rates, which are the base rates approved in MECO's 1999 test year case, with the results at proposed rates.

Q. What are the results of the cost-of-service study?

A. The results of the cost-of-service study are summarized in the following exhibits:

1) MECO-1801 compares each MECO division's revenues at present rates, at "full cost" rates (where each division earns the proposed system average rate of return), and at proposed rates;

2) MECO-1802 compares each division's class revenues and rates of return at

present rates and at proposed rates;

3) MECO-1803 provides the determination of the classes' rates of return on rate base at present rates;

4) MECO-1804 provides the determination of the classes' rates of return on rate base at proposed rates;

5) MECO-1805 show summaries of the allocation of rate increase by rate class required for each class to earn the system average rate of return;

6) MECO-1806 show summaries of the classes' revenue requirements and class rates of return at present, proposed, and equal rates of return;

7) MECO-1807 shows summaries of the classes' demand, energy, and customer costs at proposed rates;

8) MECO-1808 shows summaries of the classes' unit demand, energy, and customer costs at proposed rates;

9) MECO-1809 shows summaries of the classes' demand, energy, and customer costs at equal rates of return; and

10) MECO-1810 shows summaries of the classes' unit demand, energy, and customer costs at equal rates of return.

Q. Please discuss the divisions' revenues and rates of return presented in MECO-1801.

A. The proposed revenue increase allocation is the same percentage increase at each MECO division, as shown in MECO-1801. However, in order for each division to earn the same average return on rate base, Maui Division would require only a 4.7% increase in electric revenues, while Lanai Division and Molokai Division would require increases in electric revenues of 19.4% and 9.7%, respectively.

Q. Please discuss the classes' revenues and rates of return presented in MECO-1802.

A. At Maui Division, the results of operation for test-year 2007 show a system rate of return on rate base of 6.52% at present rates and 9.29% at proposed rates, as shown in MECO-1802. Schedule J has the highest rate of return at present rates (11.80%) and proposed rates (15.26%), while both of the other primary commercial rate schedules, Schedules G and P, earn above the Maui Division system average return. Schedule R on the other hand earns below the division average rate of return both at present and at proposed rates. At Lanai Division, the results of operation for test-year 2007 show a system rate of return on rate base of 0.75% at present rates and 3.01% at proposed rates, as shown in MECO-1802. Schedule J has the highest rate of return at present rates (6.32%) and Schedule P has the highest rate of return at proposed rates (9.08%). Schedule R earns a negative return at both present and proposed rates. Lanai Schedule R would need a 76% revenue increase in order to earn the system average rate of return, as shown in MECO-1805. The shortfall in the Lanai Division rate of return is recovered in Maui Division revenues. At Molokai Division, the results of operation for test-year 2007 show a system rate of return on rate base of 4.30% at present rates and 6.86% at proposed rates, as shown in MECO-1802. Schedule F has the highest rate of return at present rates (20.73%) and at proposed rates (22.80%). Schedule R earns a negative return at present rates (-2.13%) and is barely positive in return at proposed rates (0.24%). Schedule P (1.12%) and Schedule H (2.44%) rates of return at proposed rates are also rather low. Molokai Schedule R would need a 26% revenue increase in order to earn the system average rate of return, as shown in MECO-1805. The shortfall in the Molokai Division rate of return is also recovered in Maui Division revenues.

Q. Please describe how the proposed allocation of the revenue increase among the

divisions and rate classes was determined.

A. The proposed allocation of the revenue increase among the MECO divisions and rate classes is based on assigning an across the board increase of 5.27% to all the rate classes in each of the divisions. The assignment of the same percent rate increase to all the rate classes is discussed in MECO T-1.

EMBEDDED COST-OF-SERVICE STUDY METHODOLOGY

Q. How is the embedded cost-of-service study developed?

A. The cost-of-service study involves three major steps in determining the classes' cost responsibility, namely:

1) Functionalization of costs and rate base items into the major operating functions of production, transmission, and distribution.
2) Classification of the functionalized costs into the three cost components of energy-related costs, demand-related costs, and customer-related costs.
3) Allocation of the costs components to the different rate classes.

Each of these three steps involves detailed analysis to develop the appropriate bases and factors for classifying and allocating costs.

FUNCTIONALIZATION OF COSTS

Q. Can you briefly explain the process of functionalizing costs?

A. The functionalization process categorizes the different costs and rate base items into the major operating functions of (a) production, (b) transmission, and (c) distribution. This process enables the identification of the utility facilities and/or services that are provided to serve particular rate classes and thereby facilitate the assignment of costs.

Q. What costs are included in each operating function?

A. The costs included in each operating function are:

1) Production function costs include all costs associated with generating power including fuel costs and purchase power expense.

2) Transmission function costs include all costs associated with transferring power from power plants to substations or between switching stations at transmission voltage levels.

3) Distribution function costs include all costs associated with delivering power from the transmission voltage levels through the distribution system to the customer, and connecting the customers to the system. The distribution function is further categorized into the sub-functions of (a) substation, (b) primary lines, (c) secondary lines, (d) transformers, (e) service drops, (f) meters, (g) customer accounting, and (h) customer services. The sub-functionalization facilitates the allocation of the costs of these facilities and services to the different rate classes.

Q. How are the costs broken down into these functions and sub-functions?

A. MECO records costs using the NARUC Uniform System of Accounts which directly assigns some cost items to these functional categories. The costs associated with plant-in-service and most of the operation and maintenance expenses can be readily functionalized by account number analysis. Some costs, such as those related to general plant, administrative and general expenses, taxes, and return on capital, are not recorded by functional accounts and are not directly assigned to the major functions. These general type costs are categorized into the three major functions by analysis of their characteristics or by using an appropriate functionalization base.

CLASSIFICATION OF COSTS

Q. *Please describe the second step of the study, the classification of costs.*

A. In the classification process, each of the functionalized costs and rate base items are then classified into each of the three costs components: (a) energy-related, (b) demand-related, and (c) customer-related. This process further categorizes the costs based on what causes them to be incurred to facilitate their allocation to the various rate classes based on measurable service characteristics, such as kilowatthour consumption, kilowatt demand, and number or type of customers connected to the system.

Q. What costs are included in each of the three costs components?

A. The costs included in each of the three costs components are:

1) Energy-related costs include those costs that are incurred to produce the kilowatthour energy (kWh) used by the customers such as fuel and purchase power costs. These costs vary with the volume of kWh generated by the system.

2) Demand-related costs include those costs that are incurred to serve the customers' kilowatt demand (kW) on the utility system. The capacity size of the plant facilities is determined by the customers' kW demand on the system.

3) Customer-related costs include those costs that are incurred in order to connect the customers to the system, bill them, and maintain their service accounts, regardless of their energy consumption (kWh) or demand (kW) on the system. These costs are related to the number and type of customers, and consist of plant-related and service-related customer costs. The plant-related customer costs are the customer cost component of the distribution lines and distribution

transformers costs, and the costs of service drops and meters. The service-related customer costs are the costs of meter reading, customer billing and accounting, and customer service related expenses.

Q. How are those costs that are not directly related to kWh, kW, and/or number and type of customers, categorized to the three cost components?

A. Some costs such as taxes, are related to revenues or payroll rather than to kWh, kW, or number of customers. Revenue-related costs are directly allocated to the various rate classes based on the revenues generated from each rate class, or on the basis of the allocated O&M labor expense.

Q. Please describe how each functionalized cost is classified into the three costs components?

A. The classification of each functionalized cost is based on the NARUC Electric Utility Cost Allocation Manual dated January 1992. Following the NARUC cost classification rationale, the production function costs are classified to demand and energy components. The energy components primarily include the fuel-related expense and the energy component of the purchased power expense.

The transmission function costs are classified to demand components since the transmission systems are generally sized to meet the maximum kW loads on the system.

The distribution function costs are classified to demand and customer components. Some distribution facilities or equipment, such as the service drops and meters, are required to connect and serve the customers regardless of their kW demand, and are therefore appropriately classified to customer components. Distribution substations are normally classified as demand-related, because these facilities are normally built to serve particular load size and are not affected by the

number of customers to be served. The distribution lines and transformers are assigned to demand and customer components, since the size and costs of these facilities are dependent not only on the customers' load, but also on the type and location of the customers.

Q. How is the customer component of the distribution lines and transformers determined?

A. The customer component of the distribution lines and transformers is that portion of costs which varies with the number and location of customers. Following the NARUC cost allocation manual, MECO has used the Minimum Size Method to allocate these costs to customer-related and demand-related components.

Q. Please briefly describe the Minimum Size Method.

A. The Minimum Size Method assumes that a minimum size distribution system can be built to serve the customers' minimum service requirements. The cost of the minimum size facility, such as the minimum size pole, conductors, and transformers installed by the utility is classified as the customer-related component of these facilities. The demand-related component is the difference between the total costs of these facilities and the customer-related component.

ALLOCATION OF COSTS

Q. How is each of the three costs components allocated to the different rate classes?

A. After each cost function has been assigned to the three costs components, each cost component is then allocated to the different rate classes based on the causative service variable. For instance, the energy-related cost component varies with the kWh generated by the utility, and is therefore allocated to the different rate classes based on the classes' kWh consumption. The demand-related cost

1 component varies with kW load, and is allocated to the different rate classes based
2 on the classes kW demand. The customer-related cost component is determined
3 by the number and/or type of customers, and is therefore allocated to the different
4 rate classes based on the number of customers in each rate class, weighted to
5 reflect the differences in various customer-related services and/or activities. The
6 weighting factors reflect differences in service phase, service voltage, metering
7 requirements, and complexity of meter reading, billing, and accounting services.
8 A summary of the allocation factors for the three costs components at each
9 MECO division is provided in MECO-1811.
10 Q. Please explain how the energy allocation factors used to allocate the energy-
11 related costs, were derived?
12 A. The energy allocation factors are based on the test-year kWh sales forecasts for
13 each rate class, and adjusted for line losses. These line losses are added to the
14 kWh sales since MECO's fuel and purchased energy costs are related to the
15 energy input to the system. The determination of the classes' kWh usage
16 including line losses, used in the determination of the energy allocation factors, is
17 provided in MECO-1812.
18 Q. How were the demand allocation factors, used to allocate the demand-related
19 costs, derived?
20 A. The demand-related cost component is related to the kW demand served by the
21 system, and is therefore allocated on the basis of the customers' kW load. Unlike
22 the allocation of the energy-related and customer-related costs, there are different
23 methods of allocating demand costs. The three main demand cost allocation
24 methods are the: (a) Average-Excess Demand Method (AED Method), (b) Peak
25 Responsibility Method (PR Method), and (c) Non-Coincident Demand Method

(NCD Method). All other methods are simply variations or combinations of these three major demand cost allocation methods.

Q. *What are the differences between these three methods?*

A. Each demand cost allocation method is based on different premises as to the primary determinant of the demand-related cost which determines how customer classes contribute to the utility's demand costs.

The AED Method assumes that the utility system capacity requirement is determined not only by the maximum kW demand but also by other factors such as the system load factor and demand diversity factor. It considers both the kW load and the kWh energy consumption in allocating the demand costs. This method allocates the demand costs on the basis of each class's average demand (kWh Consumption ÷ No. of Hours) weighted by the system load factor, and the class's excess demand (Class Peak Demand – Average Demand) weighted by 1 minus the system load factor.

The PR Method assumes that the utility system capacity requirement is determined by the system peak load. This method allocates the demand cost on the basis of each class' contribution to the system peak.

The NCD Method assumes that each customer class, if served independently, will require facilities that would meet the class' maximum demand. It therefore allocates the demand costs based on the classes' maximum demands or class non-coincident peaks during the year regardless of when they occur.

Q. What demand costs allocation method did MECO use in its cost-of-service study for this proceeding?

A. As in Docket No. 97-0420, test year 1999, MECO used the AED method to

allocate the production and transmission demand costs, and the NCD method to allocate the distribution demand costs. These methods have used in the company's prior rate cases (including HELCO's and HECO's), and have been found reasonable and approved by the Commission.

Q. Why did MECO use the AED Method to allocate the production and transmission demand costs?

A. The AED Method considers several factors in allocating demand costs and results in relatively more stable results, unlike the other two major demand costs allocation methods which consider only one demand parameter in allocating demand costs. The AED Method considers the classes' demand requirements, energy consumption, and system load factor in allocating the demand costs. Given MECO's system load profile with low seasonality and broad peak periods, the AED Method has proven to be reasonable for MECO.

Q. Why did MECO use the NCD Method to allocate the distribution demand costs?

A. MECO used the NCD Method to allocate the distribution demand costs because the distribution facilities are sized to serve the maximum diversified demand at these service levels regardless of the system peak load.

Q. What load data did you use to develop the allocation factors used in the cost-of-service study.

A. The allocation factors used in the cost-of-service study are based on the results of MECO's 2005 Class Load Study. The Study is based on a total sample of customers across all rate classes, except Schedule F. The Study collected 15-minute load data from the selected sample for the entire calendar year 2005.

MARGINAL COST STUDY

Q. Have you prepared a Marginal Cost Study?

A. We have estimated marginal energy costs for Maui Division, and the results are presented in MECO-1813. The marginal energy costs are based on the estimated hourly running costs for the five-year period from 2007 to 2011, from the production simulation model. The model simulates the system generation with expected loads and expected resources including power purchases from independent producers, and expected plant maintenance and fuel prices. The hourly running costs are then aggregated by time-of-use rating periods, converted to 2007 dollars, and then adjusted to include variable o&m, A&G loadings, revenue requirements for the incremental fuel stock and working cash, marginal energy line losses.

RATE DESIGN AND PROPOSED RATES

Q. What is rate design?

A. Rate design is the conversion or translation of the Company's proposed revenue requirements for each rate class into pricing structure to collect MECO's required revenues to cover its total costs of providing service.

Q. What factors does the Company consider in designing the proposed rates?

A. MECO typically considers the following factors in developing the proposed rates:

1. production of the Company's test-year revenue requirements;
2. classes' cost of service;
3. revenue stability;
4. rate stability and rate continuity;
5. impact on customers;

6. customers choice;
7. provide fair and equitable rates;
8. simplicity, ease of understanding, and ease of implementation; and
9. encourage customer load management.

In general, changes to MECO's rates are aimed at aligning the rate elements closer to the cost components, minimizing intra-class subsidy, and moving closer to more efficient pricing that provides more accurate price signals.

Q. How did MECO develop the rate design proposed in this case?

A. MECO proposes an inclining rate block structure in Schedule R, similar in structure as HELCO's proposal in Docket No. 05-0315 and HECO's proposal in Docket No. 2006-0386. Proposed demand charges for the commercial rate classes are designed to recover a higher percentage of demand costs than in previous rate cases. The billing demand calculation in Schedule J is proposed to be modified to the same calculation as exists for Schedule P. The proposed adjustments for supply voltage delivery for Schedule G, Schedule J, Schedule F, and Schedule U are based on a test year 2007 analysis performed by the Transmission Planning division. Finally, energy charges are adjusted to achieve the proposed revenue by rate class. In the case of Schedule J, Schedule P, and Schedule F, each energy charge tier is proposed to be adjusted by approximately the same amount in cents per kWh.

MAUI DIVISION RATE DESIGN PROPOSAL

Q. What are the proposed changes to Maui Division existing rates?

A. The proposed rate design changes to each Maui Division rate schedule are summarized below:

Schedule R – Residential Service

Q. What is Schedule R?

A. Schedule R is for residential electric service applicable to individually metered residential dwelling units.

Q. What are the proposed changes to Schedule R?

A. The following are the proposed changes to Schedule R:

1) increase the Base Fuel Energy Charge from 4.5937 ¢/kWh to 17.9992 ¢/kWh; and

2) change the Non-Fuel Energy Charge from 8.8294 ¢/kWh to three tiers, 10.3229 ¢/kWh for the first 350 kWh, 11.1375 ¢/kWh for the next 850 kWh, and 11.6756 ¢/kWh for all kWh over 1,200 kWh per billing period.

The proposed changes to Schedule R are designed to produce the proposed allocated class revenue requirements of $128,342,800 as shown in MECO-1816.

Q. How is the proposed Base Fuel Energy Charge determined?

A. The proposed Base Fuel Charge of 17.9992 ¢/kWh is based on the test-year composite fuel price for base generation, base purchase power, and base cost of fuel for MECO's distributed generation units. See the calculation of the Base Fuel Energy Charge in MECO-1814.

Q. What are the merits of the proposed inclining block rate design for Non-Fuel Energy Charges?

A. The merits on an inclining block rate design include mitigation of rate impact on the smallest users of the system, pricing signals that encourage conservation, and assignment of a greater share of the cost increase to the larger users. HELCO has made a similar proposal for Schedule R in Docket No. 05-0315, its 2006 test year

rate case, and HECO also has such a proposal in Docket No. 2006-0386, its 2007 test year rate case.

Q. Does the inclining block rate design address the challenges facing low income residential ratepayers?

A. The inclining block rate design does benefit most residential ratepayers, including low income residential ratepayers, by offering a lower electricity price for the initial kWh of usage. However, the Company recognizes that the rate design alone does not fully address the challenges facing low income residents whose usage extends beyond the boundary of the first tier. The Company plans to develop a program to address the issues of low income residential ratepayers, and plans to introduce its proposal subsequently in this case.

Q. What are the features of the inclining block rate proposal for the proposed Non-Fuel Energy Charges?

A. The features are three tiers, one for the first 350 kWh used in the billing period, one for the next 850 kWh used in the billing period, or kWh usage between 350 kWh and 1,200 kWh, and a third tier for kWh usage above 1,200 kWh per billing period. Each tier has a different non-fuel energy charge per kWh, with the first 350 kWh having the lowest proposed non-fuel energy charge and kWh usage over 1,200 kWh having the highest proposed non-fuel energy charge.

Q. How were the sizes of the kWh tiers determined?

A. The first tier, up to 350 kWh, was set to provide the lowest energy rate for a base kWh usage level. The second tier, from 350 kWh to 1,200 kWh, was to set to capture the majority of the kWh. As shown in MECO-1815, about 26% of customer bills fall into the lowest tier, 62% of customer bills fall into the middle tier, and 12% of the customer bills fall into the highest tier. However,

approximately 89% of all kWh will be billed at either the first or second tier rate. The tiers are designed so that most of the usage is covered by the first two tiers and only the very highest residential customer usage will incur the third tier energy charges.

Q. How were the Non-Fuel Energy Charges for the kWh tiers determined?

A. The guidelines used to determine the non-fuel energy charges for the kWh tiers were to collect the demand and customer costs that are not recovered by the customer and minimum charges, to target approximately a 2% to 3% bill increase for customers whose billing quantities fell into the first tier only, and to target no more than approximately the class average increase, 5.3%, for customers whose billing quantities fell into the first and second tiers. Note that the proposed rate increase for billing quantities up to 350 kWh ranges up to 3.2%, the proposed rate increase for billing quantities between 350 kWh and 1,200 kWh ranges between 3.2% and 5.5%, and the proposed rate increase for billing quantities above 1,200 kWh ranges between 5.5% and 8.3% compared to present rates.

Q. What is the impact of the proposed changes to Schedule R on the residential customers?

A. MECO-1819 compares the residential electric bills under the present rates and proposed rates for various consumption levels.

<u>Schedule E – Electric Service for Employees</u>

Q. What is Schedule E?

A. Schedule E is for electric residential service for Company employees and retirees, and members of the Company's Board of Directors.

Q. Are there any changes to Schedule E?

A. No. There are no proposed changes to Schedule E.

Schedule G – General Service Non-Demand

Q. What is Schedule G?

A. Schedule G is for general power service applicable to small commercial customers with loads not exceeding 5,000 kWh per month or loads less than or equal to 25 kW.

Q. What are the proposed changes to Schedule G?

A. The following are the proposed changes to Schedule G:

1) increase the Customer Charge from $21.00 to $25.00 per month for Single-Phase service, and from $36.00 to $40.00 per month for Three-Phase service;
2) increase the Energy Charge from 14.5656 ¢/kWh to 29.8037 ¢/kWh;
3) increase the Minimum Charge from $26.00 to $30.00 per month for Single-Phase service, and from $41.00 to $45.00 per month for Three-Phase service; and
4) change the Primary Supply Voltage Service from 2.0% to 1.1% for distribution primary (DP) customers, and from 1.0% to 0.5% for distribution secondary (DS) customers.

The proposed changes to Schedule G are designed to produce the proposed allocated class revenue requirements of $31,384,400 as shown in MECO-1816.

Q. How did you determine the proposed customer charge for Single-Phase and Three-Phase Service?

A. The proposed customer charges are designed to recover about three-quarters of the Schedule G customer cost of service, which is slightly below the levels from the

final rate design in MECO's test year 1999 rate case.

Q. How are the proposed minimum charges for Single-Phase and Three-Phase service determined?

A. The proposed minimum charges maintain the $5.00 difference between customer charges and minimum charges that are contained in existing rates.

Q. How is the proposed Energy Charge of 29.8037 ¢/kWh determined?

A. The proposed Energy Charge of 29.8037 ¢/kWh recovers the remainder of the class' allocated revenue requirements at proposed rates that are not recovered from the proposed customer charges and minimum charges. This includes all of the class' energy costs and the remainder of the class' allocated fixed costs.

Q. How are the proposed changes to the Primary Supply Voltage adjustments determined?

A. The proposed changes to the Primary Supply Voltage adjustments are based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule G customers?

A. MECO-1819 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

<u>Schedule J – General Service Demand</u>

Q. What is Schedule J?

A. Schedule J is for general power service applicable to commercial customers with loads greater than 5,000 kWh per month or greater than 25 kW. The current Schedule J allows commercial customers to change service from Schedule J to any of the applicable large power service (Schedule P). The proposed modification to

Schedule J's Availability Clause is to clarify the load limits for the medium-sized commercial customers that qualify for service under Schedule J.

Q. What are the proposed changes to Schedule J?

A. The following are the proposed changes to Schedule J:

1) increase the Customer Charge from $35.00 to $50.00 per month for Single-Phase service, and from $50.00 to $65.00 per month for Three-Phase service;
2) increase the Demand Charge from $5.75 to $12.00 per kW;
3) increase the Energy Charge for the three load factor blocks from 12.4165 ¢/kWh, 11.4024 ¢/kWh, and 8.4403 ¢/kWh to 25.5003 ¢/kWh, 24.4862 ¢/kWh, and 21.5241 ¢/kWh, respectively;
4) change the Availability Clause to clarify the current load thresholds and to add a maximum qualifying load less than 200 kW to new customers, and add a clause that would allow customers with loads equal or greater than 200 kW currently receiving service under Schedule J to remain under Schedule J;
5) change the demand ratchet in determining the billing demand under the Determination of Demand provision from the current 75% ratchet to the average demand ratchet; and
6) change the supply voltage adjustments in the Primary Supply Voltage Service provision from 2.0% to 1.1% for distribution primary supply voltage (DP adj.), and from 1.0% to 0.5% for distribution secondary supply voltage (DS adj.).

The proposed changes to Schedule J rates are designed to produce the proposed allocated class' revenue requirements of $78,984,600 as shown in

MECO-1816.

Q. How are the proposed customer charges of $50.00 and $65.00 per month for Single-Phase and Three-Phase service, respectively, determined?

A. The proposed customer charges recover just over one-half of the customer cost shown in the cost of service study, which is slightly less than the percentage recovery in current rates.

Q. How is the proposed demand charge of $12.00 per kW determined?

A. The proposed demand charge of $12.00 per kW is based on about 37% of the class's full unit demand cost. In the existing rates, the Schedule J demand charge recovers about 22% of the demand cost. MECO proposes to increase the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service.

Q. How are the proposed energy charges determined?

A. The proposed energy charges the three load factor blocks are designed to recover all of the class's allocated energy costs as well as the remaining customer-related and demand-related costs that are not recovered in the proposed customer and demand charges. The proposed energy charges are approximately the same rate increase in cents per kWh in each energy charge block.

Q. Why is the Company proposing a maximum qualifying load of less than 200 kW for Schedule J?

A. MECO's proposal to define a maximum qualifying load under Schedule J is based on the following reasons:

1) to better define and clarify the load size that qualifies under Schedule J for ease of understanding and application;
2) to make a clearer distinction between the medium-sized customers

served under Schedule J, and the large power customers served under the Schedule P;

3) to apply Schedule J to a more homogenous group of medium-size commercial and industrial customers with similar load levels and characteristics, essential for designing more efficient pricing and costing, and facilitate aligning rates closer to cost of service; and

4) to support rate and revenue stability and continuity.

Q. Will customers currently served under Schedule J with loads equal to or greater than 200 kW be allowed to stay on Schedule J?

A. Yes. These customers will be grandfathered and can remain to be served under Schedule J, if they chose. The new proposed maximum qualifying load under Schedule J will apply to new customers.

Q. Why is MECO proposing to change Schedule J's demand ratchet?

A. MECO is proposing to change Schedule J's demand ratchet for determining the billing kW from the current 75% ratchet to average demand ratchet for simplicity and ease of understanding. The proposed average demand ratchet is the same as the current demand ratchet in Schedule P, making the demand ratchet provisions for all the demand rate schedules the same and consistent. The average demand ratchet compares the customer's maximum demand for the current billing period with the average of his current maximum demand and his maximum demand for the last 11 months, as well as with Schedule J's minimum billing demand of 25 kW – in determining the customer's billing kW demand. The customer's demand charge is based on the highest of these three demand values.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments for

distribution primary supply voltage and distribution secondary supply voltage is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule J customers?

A. MECO-1819 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule H – Commercial Cooking, Heating, Air Conditioning, and Refrigeration Service

Q. What is Schedule H?

A. Schedule H is an end-use rate that applies to specific commercial electric loads including commercial cooking, heating, air conditioning, and refrigeration loads that are less than 600 volts.

Q. What are the proposed changes to Schedule H?

A. The following are the proposed changes to Schedule H:

1) increase the Customer Charge from $27.00 to $40.00 per month for Single-Phase service, and from $43.00 to $55.00 per month for Three-Phase service;
2) increase the Demand Charge from $4.50 per kWb to $7.00 per kWb;
3) increase the Energy Charge from 11.9675 ¢/kWh to 26.3728 ¢/kWh; and
4) close the rate schedule to new customers.

The proposed changes to Schedule H are designed to produce the class's total allocated revenue requirements of $6,221,100 as shown in MECO-1816.

Q. How are the proposed customer charge of $40.00 per month for Single-Phase service and $55.00 per month for Three-Phase service determined?

A. The proposed customer charges recover about one-quarter of the customer cost shown in the cost of service study, which is less than the percentage recovery in current rates.

Q. How is the proposed demand charge of $7.00 per kW determined?

A. The proposed demand charge of $7.00 per kW is based on about 27% of the class's full unit demand cost, compared to the current demand charge's recovery of about 17% of current demand cost. MECO proposes to increase the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service.

Q. How did you determine the proposed Energy Charge?

A. The proposed energy charge is based on recovering the class's total allocated energy-related and demand-related costs as well as the remaining customer-related costs that are not recovered from the proposed customer charge.

Q. Why is MECO proposing to close Schedule H to new customers?

A. With the proposals to define kW limits in Schedules J and P, MECO is moving towards clearer distinctions between its commercial customers. The number of Schedule H customers is relatively small compared to the number of Schedules G, J, or P customers. MECO would like to close the Schedule H to new customers in order to plan for a transition for the existing Schedule H customers. The same proposal has been advanced in the open HELCO and HECO rate cases.

Q. Does that mean that no customer can have new Schedule H service?

A. The Company proposes that there will be no new Schedule H service connections, with the exception of allowing customers with existing Schedule H service to re-locate their Schedule H service. That is, a customer who terminates Schedule H service in one location will be allowed to contemporaneously open a new

Schedule H service in another service location. There is no net gain of Schedule H customers in this situation.

Q. What is the impact of the proposed changes to Schedule H customers?

A. MECO-1819 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule P – Large Power Service

Q. What is Schedule P?

A. Schedule P is for general power service applicable to commercial or industrial customers with large power loads of at least 200 kW.

Q. What are the proposed changes to Schedule P?

A. The following are the proposed changes to Schedule P:

1) increase the Customer Charge from $225.00 to $375.00 per month;
2) increase the Demand Charge for the two demand blocks from $8.50 per kW and $8.00 per kW to $18.00 and $17.00 per kW, respectively;
3) increase the Energy Charge for the three load factor blocks from 10.9997 ¢/kWh, 9.4576 ¢/kWh, and 7.7456 ¢/kWh, to 24.4694 ¢/kWh, 22.9273 ¢/kWh, and 21.2153 ¢/kWh, respectively; and
4) change the service voltage adjustments in the Supply Voltage Delivery provision from the current 4.9%, 3.9%, 2.0%, and 1.0% for transmission primary, transmission secondary, distribution primary, and distribution secondary, to 4.4 %, 3.8%, 1.1%, and 0.5 %, respectively.

The proposed changes to Schedule P rates are designed to produce the proposed allocated class' revenue requirements of $104,203,500 as shown in MECO-1816.

Q. Please explain how the proposed customer charge was determined?

A. The proposed customer charges recover about one-half of the customer cost shown in the cost of service study, which is less than the percentage recovery in current rates.

Q. Please explain how you determined the proposed demand charges?

A. The proposed demand charge for the first demand block is designed to recover approximately 46% of the class's unit demand cost, compared to about 27% recovery in existing rates. MECO proposes to increase the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service. The proposed demand charge for the 2nd demand block recovers about 44% of demand cost.

Q. How are the proposed energy charges determined?

A. The proposed energy charges are based on recovering the class's proposed allocated total revenue requirements less the revenues recovered from the proposed customer and demand charges. This includes the entire energy-related costs (or variable costs) and the remainder of the customer-related costs and the demand-related costs (or fixed costs) that are not recovered from the proposed customer and demand charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule P energy block rates.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule P customers?

A. MECO-1819 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule F – Public Street Lighting

Q. What is Schedule F?

A. Schedule F is for public street and highway lighting.

Q. What are the proposed changes to Schedule F?

A. The following are the proposed changes to Schedule F:

1) increase the energy charge for the two load factor blocks from the current 15.1733 ¢/kWh and 10.6753 ¢/kWh to 30.5954 ¢/kWh and 26.0974 ¢/kWh, respectively.

The proposed changes to Schedule F rates are designed to produce the proposed allocated class' revenue requirements of $1,496,100, as shown in MECO-1816.

Q. Please explain how you derived the proposed energy charges for the two load factor blocks?

A. Like Schedule R and Schedule G, the proposed energy rates for Schedule F are determined to recover the remainder of the class' allocated revenue requirements at proposed rates that are not recovered in the proposed customer and minimum charges. This includes the class's entire energy cost and the remainder of the customer and demand costs that are not recovered in the proposed customer and minimum charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule F energy block rates.

Q. What is the impact of the proposed changes to Schedule F customers?

A. MECO-1819 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule U – Time-of-Use Service

Q. What is Schedule U?

A. Schedule U is an optional Time-of-Use Service for commercial or industrial customers with loads of at least 25 kW. Customers who qualify for service under Schedule J or P can elect to be served under Schedule U.

Schedule U provides an on-peak demand charge and time-differentiated energy rates. For instance, the demand charge is applied only to kW load used during the on-peak period, and the energy rates are differentiated by the time-of-use rating periods. Service under Schedule U is based on customer election.

Q. What are the proposed changes to Schedule U?

A. The proposed changes to Schedule U include the following:

1) increase the Energy Charge from the current 12.4165 ¢/kWh for the on-peak period to 25.5003 ¢/kWh, and from 7.7456 ¢/kWh for the off-peak period to 21.2153 ¢/kWh;
2) change the service voltage adjustments in the Supply Voltage Delivery provision from the current 4.9%, 3.9%, 2.0%, and 1.0% for transmission primary, transmission secondary, distribution primary, and distribution secondary, to 4.4 %, 3.8%, 1.1%, and 0.5 %, respectively; and
3) close the Schedule to new customers.

Q. How did you determine the proposed time-of-use energy rates for Schedule U?

A. The proposed On-Peak Energy Rate of 25.5003 ¢/kWh is the same as the first block energy rate in the proposed Schedule J charges, and the proposed Off-Peak

Energy Rate of 21.2153 ¢/kWh is the same as the third block energy rate in the proposed Schedule P charges. This is the same derivation that was used in test year 1999 to set the existing Schedule U rates.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. Why is the Company proposing to close Schedule U to new customers?

A. There are no customers currently receiving Schedule U service. The Company wants to target the time-of-use rate options to specific classes of customers. The Company proposes in this docket to offer a time-of-use option only for Schedule J customers (TOU-J) and a time-of-use option only for Schedule P customers (TOU-P), rather than have one rate option (Schedule U) try to serve both classes of customers. A discussion of the Company's new time-of-use proposals follows below.

Rider T – Time-of-Day Rider

Q. What is Rider T?

A. Rider T is an optional time-of-use service rider for commercial or industrial customers with power loads of at least 25 kW who are served under Schedule J, or Schedule P. Rider T modifies or provides adjustments to the applicable rate schedule's demand and energy rates, which effectively results in time-of-use price signals. It was aimed at encouraging customers to manage their loads in order to help reduce the system peak load and defer the need for the next capacity addition.

Q. Is MECO proposing any changes to the Rider T?

A. Yes. MECO is proposing the following changes to Rider T:

1) add terms and conditions that would allow customers to do emergency maintenance on their equipment without considering its impact on the customers' maximum on-peak demand in the determination of their billing demand.

Rider M – Off-Peak and Curtailable Service

Q. What is Rider M?

A. Rider M is an optional off-peak and Curtailable service applicable to Schedule J customers with loads greater than 100 kW, and to customers served under Schedule P with loads greater than 300 kW. Rider M provides load management incentives to customers by modifying the determination of the billing demand under Schedules J or P. It offers two load management service options: Option A – Off-Peak Service, and Option B – Curtailable Service.

The Rider M – Off-Peak Service (Option A) encourages customers to shift their load to the off-peak hours by basing the determination of the billing demand only on the customers' kW demand during the on-peak period. The Rider M – Curtailable Service (Option B) encourages customers to shift their load to off-peak hours by reducing the customers' billing demand by 75% of the kW load that they curtail during the Company's priority peak period, or by 40% of the kW load that they curtail for a two-hour duration specified by the Company.

Q. Is MECO proposing any changes to Rider M?

A. Yes. The following are the proposed changes to Rider M:

1) modify the Availability Clause to appropriately reference the new Schedule TOU-J and Schedule TOU-P.

Rider I – Interruptible Contract Service

Q. What is Rider I?

A. Rider I is an optional interruptible service available to large power customers with interruptible kW load of at least 500 kW.

Q. Did MECO propose any changes to Rider I?

A. No, no changes are proposed.

Schedule Q – Purchases from Qualifying Facilities 100 kW or Less

Q. What is Schedule Q?

A. Schedule Q applies to customers with small production facilities with design capacity of 100 kW or less, qualifying under Chapter 74, Title 6 of the PUC Rules, and who have a purchase power contract with the Company. Schedule Q provides the energy rates and energy cost adjustment that the Company pays for energy purchased by the Company from the customer, and the metering charge to the customer for metering, billing and administration of the purchase power contract.

Q. Are there proposed changes to Schedule Q?

A. Yes. The following are the proposed changes to Schedule Q:

1) change the Energy Rates for energy delivered to the Company by the customer from the current 4.80 ¢/kWh to 19.32 ¢/kWh; and
2) change the generation base fuel cost from the current 369.60 ¢/mbtu to 1,547.97 ¢/mbtu.

Q. How was the proposed energy rate of 19.32 ¢/kWH for energy delivered to MECO determined?

A. The proposed energy rate of 19.32 ¢/kWh for energy delivered by the customer to

MECO is based on the test-year estimates of the Company's generation cost and Distributed Generation cost and efficiency factors discussed in MECO T-4.

Q. What is the basis of the changes to Schedule Q's Energy Cost Adjustment Clause?

A. The proposed 1,547.97 ¢/mbtu in Schedule Q's Energy Cost Adjustment Clause is based on the test-year estimate of the total composite generation cost including Distributed Generation costs and discussed in MECO T-19. The test-year fuel price and efficiency factors used to determine this composite generation cost are discussed in MECO T-4.

Energy Cost Adjustment Clause

Q. What is the Energy Cost Adjustment Clause?

A. The Energy Cost Adjustment Clause (ECAC) is a reconciliation mechanism that allows the Company to recover or refund the difference between the fuel price embedded in the base rates and the fuel price that it actually pays.

Q. What are the proposed changes to ECAC?

A. The following are the proposed changes to ECAC:

1) modify the ECAC's Applicability Clause to include the new Schedule TOU-R, Schedule TOU-G, Schedule TOU-J, and Schedule TOU-P;
2) change the base fuel cost for Company generation from the current 369.60 ¢/mbtu to 1,547.93 ¢/mbtu Company composite cost of generation from central station and other generation;
3) change the Company generation efficiency factor from the current 0.011032 mmbtu/kWh to use three separate efficiency factors, 0.015311 mmbtu/kWh for industrial fuel oil (IFO), 0.009460 mmbtu/kWh for diesel fuel, and 0.010648 mmbtu/kWh for other company generation sources;

4) add a distributed generation (DG) energy component in the Clause at 15.007 cents per kWh, adjusted to the sales delivery level and for revenue taxes; and

5) change the base purchased energy cost from the current 5.028 ¢/kWh to 22.250 ¢/kWh.

Q. How are the proposed changes to the above ECAC parameters determined?

A. The proposed changes to the base fuel costs, generation efficiency factors, DG energy component, and base purchased energy cost are discussed in MECO T-4. The ECAC calculations are presented in MECO T-19.

Integrated Resource Planning Cost Recovery Provision

Q. What is the Integrated Resource Planning Cost Recovery Provision ("IRP Clause")?

A. The IRP Clause is a cost recovery mechanism for the incremental costs incurred by the Company related to incremental IRP-related activities, and the recovery of the incremental DSM costs which include program costs (excluding base labor), lost margin and shareholder incentives.

Q. Does the Company still require an IRP clause?

A. Yes. The Company will have to retain the IRP clause for use in reconciling the recovery of the 1995-2005 IRP costs that MECO already recovered per stipulated agreement with the CA subject to refund with interest, with the amounts of such costs that the PUC would ultimately find reasonable and allow MECO to recover. Additionally, MECO will also use the current IRP clause to recover DSM program costs that are approved for recovery by the Commission.

Green Pricing Program Provision

Q. What is the Green Pricing Program Provision?

A. The Green Pricing Program Provision is a voluntary fund-raising program that is open to Island residents and non-residents for purposes of funding the development of renewable energy facilities on the Island. The voluntary contributions received from this Green Pricing Program have been used for such programs as the Sun Power for Schools Pilot Program which funds the installation of photovoltaic systems in public schools.

Q. Are there changes proposed to the Green Pricing Program?

A. No. There are no changes proposed to the Green Pricing Program.

New Rate Schedules

Q. Is MECO proposing any new rate schedules for Maui Division?

A. Yes. MECO is proposing four new rate schedules for Maui Division:

1) Schedule TOU-R – Residential Time-of-Use Service;
2) Schedule TOU-G – Small Commercial Time-of-Use Service;
3) Schedule TOU-J – Commercial Time-of-Use Service; and
4) Schedule TOU-P – Large Power Time-of-Use Service.

Optional Time-of-Use Service Rate Schedules

Q. Please describe the goals of offering four new time-of-use rate options in this case.

A. The Company proposes to offer four new time-of-use rate options in this case, Schedule TOU-R – Residential Time-of-Use Service, Schedule TOU-G – Small Commercial Time-of-Use Service, Schedule TOU-J – Commercial Time-of-Use Service, and Schedule TOU-P – Large Power Time-of-Use Service, in order to

extend to all customers the opportunity to choose time-of-use rates, to establish a consistency in rate design for all time-of-use rate options, and to manage participation and collect data for future time-of-use rate designs. Making time-of-use rate options available to all customers, with the exception of street light customers, is consistent with the approach taken in the recent HECO rate cases, Docket No. 04-0113 and Docket No. 2006-0386, as well as in HELCO's test year 2006 rate case, Docket No. 05-0315. It is consistent with the goals of the Energy Policy Act of 2005. The proposed time-of-use rate options have consistent time-of-use rating periods (priority peak, mid-peak, and off-peak periods) and consistent rate designs (demand charge based on priority peak and mid-peak, no demand ratchet, separate energy charges for each rating period). The time-of-use rate options are intended to create lower electric bills for customers who modify their existing energy consumption patterns. The Company proposes to manage participation in these optional rates while collecting data for future time-of-use rate design offerings by setting a limit on the number of meters that can participate in certain optional rate schedules. The meter limit facilitates effective implementation of these rate options since the current billing system cannot bill time-of-use rates automatically, and in case the new Customer Information System (CIS) is not yet in place by the time these proposed rates are approved. In addition, the Company has not estimated any revenue adjustment for customer participation in these time-of-use rate options, so the meter limit helps to mitigate any negative revenue impact that the Company might experience in implementing these rate options.

Schedule TOU-R – Residential Time-of-Use Service

Q. Please describe MECO's proposed Schedule TOU-R for Maui Division.

A. Customers currently served under Schedule R are eligible to elect time-of-use service under Schedule TOU-R. The proposed Schedule TOU-R has the following parameters:

1. Customer Charge: $7.50 per month for Single-Phase Service, and $12.00 per month for Three-Phase service;
2. Energy Charge: Calculated in the same manner and at the same rates as the proposed Schedule R, with the following time-of-use energy rate adjustments:

Priority Peak Period kWh use	+ 5.0 ¢ per kWh,
Mid-Peak Period kWh use	+ 2.5 ¢ per kWh, and
Off-Peak Period kWh use	- 5.0 ¢ per kWh;

3. Minimum Bill is the same as proposed for Schedule R;
4. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily; and

5. Service is limited to a maximum of 300 meters across all three MECO divisions.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $7.50 for Single-Phase Service and $12.00 for Three-Phase Service are the same as the proposed customer charges for

Schedule R.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate adjustment for all kWh used in the priority peak period of + 5.0 ¢/kWh is based on 250% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of +2.5 ¢/kWh is based on 125% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period is based on about 170% of the existing off-peak energy credit for Rider T customers. However, even at the lowest energy tier, the effective off-peak kWh rate on Schedule TOU-R exceeds the off-peak marginal energy cost rate for 2007, and therefore makes a contribution towards fixed cost recovery.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-R are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

<u>Schedule TOU-G – Small Commercial Time-of-Use Service</u>

Q. Please describe MECO's proposed Schedule TOU-G for Maui Division.

A. Customers currently served under Schedule G are eligible to elect time-of-use service under Schedule TOU-G. The proposed Schedule TOU-G has the following parameters:

1. Customer Charge: $25.00 per month for Single-Phase Service, and $40.00 per month for Three-Phase service;
2. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	34.8037 ¢ per kWh,
Mid-Peak Period kWh use	32.3037 ¢ per kWh, and
Off-Peak Period kWh use	24.8037 ¢ per kWh;

3. Minimum Bill is the same as the proposed Schedule TOU-G customer charge;
4. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily; and

5. Service is limited to a maximum of 100 meters across all three MECO divisions.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $25.00 for Single-Phase Service and $40.00 for Three-Phase Service are the same as the proposed customer charges for Schedule G.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 34.8037 ¢/kWh is based on the proposed Schedule G energy rate plus 250% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 32.3037 ¢/kWh is based on the proposed Schedule G energy rate plus 125% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 24.8037 ¢/kWh

is based on the proposed Schedule G energy rate less about 170% of the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-G exceeds the off-peak marginal energy cost rate for 2007, and therefore makes a contribution towards fixed cost recovery.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-G are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Schedule TOU-J – Commercial Time-of-Use Service

Q. Please describe MECO's proposed Schedule TOU-J for Maui Division.

A. Customers currently served under Schedule J are eligible to elect time-of-use service under Schedule TOU-J. The proposed Schedule TOU-J has the following parameters:

1. Customer Charge: $60.00 per month for Single-Phase Service, and $75.00 per month for Three-Phase service;
2. Demand Charge of $16.00 per kW if customer's maximum demand occurs during the priority peak period and $12.00 per kW if it occurs during the mid-peak period.
3. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	30.9283 ¢ per kWh,
Mid-Peak Period kWh use	28.9283 ¢ per kWh, and
Off-Peak Period kWh use	18.9283 ¢ per kWh;

4. Minimum Bill is the same as proposed for Schedule J, the sum of the Customer Charge and the Demand Charge; and

5. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $60.00 for Single-Phase Service and $75.00 for Three-Phase Service are based on the proposed customer charges for Schedule J, plus an additional $10.00 per month, which is the same as the current time-of-use meter charge in Rider T and Rider M.

Q. Please explain the proposed demand charge for Schedule TOU-J.

A. The proposed demand charge under Schedule TOU-J is based on the customer's maximum measured kW demand for the billing period. The Company is not proposing a demand ratchet in the determination of the billing demand – the same as in the current Schedule U. However, the minimum billing demand of 25 kW still applies. If the customer's maximum measured kW demand for the billing period occurs during the priority peak hours, the priority peak demand charge of $16.00 per kW is applied. If the customer's maximum measured kW demand for the billing period occurs during the mid-peak hours, the mid-peak demand charge of $12.00 per kW is applied. In other words, a customer is charged either the $16.00 per kW Priority Peak demand charge or the $12.00 per kW Mid-Peak demand charge based on when his maximum kW demand occurs. There is no demand charge for kW load during the off-peak hours. The determination of demand provision in the proposed Schedule TOU-J specifies the application of the

proposed demand charge.

Q. How did you determine the proposed priority peak demand charge and the mid-peak demand charge?

A. The proposed demand charge of $16.00 per kW for the priority peak period is based on recovering approximately 50% of full unit demand cost for Schedule J at proposed rates. The proposed demand charge of $12.00 per kW for mid-peak period is the same as the proposed demand charge for Schedule J.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 30.9283 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates plus 300% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 28.9283 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates plus 200% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 18.9283 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates less about 200% of the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-J exceeds the off-peak marginal energy cost rate for 2007.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-J are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Schedule TOU-P – Large Power Time-of-Use Service

Q. Please describe MECO's proposed Schedule TOU-P for Maui Division.

A. Customers currently served under Schedule P are eligible to elect time-of-use service under Schedule TOU-P. The proposed Schedule TOU-P has the following parameters:

1. Customer Charge: $385.00 per month;
2. Demand Charge of $19.50 per kW if customer's maximum demand occurs during the priority peak period and $18.00 per kW if it occurs during the mid-peak period.
3. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	29.2018 ¢ per kWh,
Mid-Peak Period kWh use	27.2018 ¢ per kWh, and
Off-Peak Period kWh use	17.2018 ¢ per kWh;

4. Minimum Bill is the same as proposed for Schedule P, the sum of the Customer Charge and the Demand Charge; and
5. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily.

Q. How did you determine proposed customer charge?

A. The proposed customer charge of $385.00 per month is based on the proposed customer charge for Schedule P, plus an additional $10.00 per month, which is the same as the current time-of-use meter charge in Rider T and Rider M.

Q. Please explain the proposed demand charge for Schedule TOU-P.

A. The proposed demand charge under Schedule TOU-P is based on the customer's maximum measured kW demand for the billing period. The Company is not proposing a demand ratchet in the determination of the billing demand – the same as in the current effective Schedule U. However, the minimum billing demand of 200 kW still applies. If the customer's maximum measured kW demand for the billing period occurs during the priority peak hours, the priority peak demand charge of $19.50 per kW is applied. If the customer's maximum measured kW demand for the billing period occurs during the mid-peak hours, the mid-peak demand charge of $18.00 per kW is applied. In other words, a customer is charged either the $19.50 per kW Priority Peak demand charge or the $18.00 per kW Mid-Peak demand charge based on when his maximum kW demand occurs. There is no demand charge for kW load during the off-peak hours. The determination of demand provision in the proposed Schedule TOU-P specifies the application of the proposed demand charge.

Q. How did you determine the proposed priority peak demand charge and the mid-peak demand charge?

A. The proposed demand charge of $19.50 per kW for the priority peak period is based on recovering approximately 50% of full unit demand cost for Schedule P at proposed rates. The proposed demand charge of $18.00 per kW for mid-peak period is the same as the proposed demand charge for the first kW tier on Schedule P.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 29.2018 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates plus 300% of the existing on-peak energy surcharge for Rider T

customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 27.2018 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates plus 200% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 17.2018 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates less about 200% of the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-P exceeds the off-peak marginal energy cost rate for 2007.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-P are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Standby Rates

Q. Are there any other proposed new rates?

A. Pursuant to Decision and Order No. 22248 in Docket No. 03-0371 on Distributed Generation, the Company proposed Standby Rates for Maui, Lanai, and Molokai Divisions. The proposed Standby Rates will be reviewed in a separate proceeding, Docket No. 2006-0497, pursuant to the Commission's Order No. 23171.

Electric Vehicle Charging Rates

Q. Is MECO proposing to terminate any existing rate schedule or rate adjustment for Maui Division?

A. Yes. MECO is proposing to withdraw the Rider EV-R – Residential Electric

Vehicle Charging Service, Rider EV-C – Commercial Electric Vehicle Charging Service. MECO is also terminating the Firm Capacity Surcharge refund for the termination of capacity payments to Pioneer Mill. This reduction in capacity payments is reflected in the test-year estimates of the purchased power expense and embedded in the new proposed rate changes.

Q. Why is MECO proposing to withdraw Riders EV-R and EV-C?

A. HECO's Rider EV-R and Rider EV-C became effective on July 6, 1998. On August 13, 1998, HECO agreed to defer implementation of the riders per Commission's request in an August 3, 1998 letter. HECO has not received PUC approval to implement these riders, although they remained in MECO's current effective rates.

More importantly, MECO's proposed Schedule TOU-R, Schedule TOU-G, Schedule TOU-J, and Schedule TOU-P will also apply to electric vehicle charging service. These proposed new Schedules will provide time-of-use service to electric vehicle charging without the need to separately meter these loads from the rest of the customers' electric loads, as required under the Rider EV-R and Rider EV-C, which were available only for the electric vehicle charging load.

LANAI DIVISION RATE DESIGN PROPOSAL

Q. What are the proposed changes to Lanai Division existing rates?

A. The proposed rate design changes to each Lanai Division rate schedule are summarized below:

Schedule R – Residential Service

Q. What is Schedule R?

A. Schedule R is for residential electric service applicable to individually metered

residential dwelling units.

Q. What are the proposed changes to Schedule R?

A. The following are the proposed changes to Schedule R:

1. increase the Base Fuel Energy Charge from 9.0620 ¢/kWh to 22.7573 ¢/kWh; and
2. change the Non-Fuel Energy Charge from 9.0028 ¢/kWh to three tiers, 10.4932 ¢/kWh for the first 250 kWh, 10.9998 ¢/kWh for the next 500 kWh, and 11.7853 ¢/kWh for all kWh over 750 kWh per billing period.

The proposed changes to Schedule R are designed to produce the proposed allocated class revenue requirements of $2,875,600 as shown in MECO-1817.

Q. How is the proposed Base Fuel Energy Charge determined?

A. The proposed Base Fuel Charge of 22.7573 ¢/kWh is based on the test-year composite fuel price for base generation, base purchase power, and base cost of fuel for MECO's distributed generation units. See the calculation of the Base Fuel Energy Charge in MECO-1814.

Q. What are the merits of the proposed inclining block rate design for Non-Fuel Energy Charges?

A. The merits on an inclining block rate design include mitigation of rate impact on the smallest users of the system, pricing signals that encourage conservation, and assignment of a greater share of the cost increase to the larger users. HELCO has made a similar proposal for Schedule R in Docket No. 05-0315, its 2006 test year rate case, and HECO also has such a proposal in Docket No. 2006-0386, its 2007 test year rate case.

Q. Does the inclining block rate design address the challenges facing low income residential ratepayers?

A. The inclining block rate design does benefit most residential ratepayers, including low income residential ratepayers, by offering a lower electricity price for the initial kWh of usage. However, the Company recognizes that the rate design alone does not fully address the challenges facing low income residents whose usage extends beyond the boundary of the first tier. The Company plans to develop a program to address the issues of low income residential ratepayers, and plans to introduce its proposal subsequently in this case.

Q. What are the features of the inclining block rate proposal for the proposed Non-Fuel Energy Charges?

A. The features are three tiers, one for the first 250 kWh used in the billing period, one for the next 500 kWh used in the billing period, or kWh usage between 250 kWh and 750 kWh, and a third tier for kWh usage above 750 kWh per billing period. Each tier has a different non-fuel energy charge per kWh, with the first 250 kWh having the lowest proposed non-fuel energy charge and kWh usage over 750 kWh having the highest proposed non-fuel energy charge.

Q. How were the sizes of the kWh tiers determined?

A. The first tier, up to 250 kWh, was set to provide the lowest energy rate for a base kWh usage level. The second tier, from 250 kWh to 750 kWh, was to set to capture the majority of the kWh. As shown in MECO-1815, about 29% of customer bills fall into the lowest tier, 57% of customer bills fall into the middle tier, and 14% of the customer bills fall into the highest tier. However, approximately 86% of all kWh will be billed at either the first or second tier rate. The tiers are designed so that most of the usage is covered by the first two tiers and only the very highest residential customer usage will incur the third tier energy charges.

Q. How were the Non-Fuel Energy Charges for the kWh tiers determined?

A. The guidelines used to determine the non-fuel energy charges for the kWh tiers were to collect the demand and customer costs that are not recovered by the customer and minimum charges, to target approximately a 2% to 3% bill increase for customers whose billing quantities fell into the first tier only, and to target no more than approximately the class average increase, 5.3%, for customers whose billing quantities fell into the first and second tiers. Note that the proposed rate increase for billing quantities up to 250 kWh ranges up to 3.6%, the proposed rate increase for billing quantities between 250 kWh and 750 kWh ranges between 3.6% and 4.9%, and the proposed rate increase for billing quantities above 750 kWh ranges between 4.9% and 7.9% compared to present rates.

Q. What is the impact of the proposed changes to Schedule R on the residential customers?

A. MECO-1820 compares the residential electric bills under the present rates and proposed rates for various consumption levels.

<u>Schedule E – Electric Service for Employees</u>

Q. What is Schedule E?

A. Schedule E is for electric residential service for Company employees and retirees, and members of the Company's Board of Directors.

Q. Are there any changes to Schedule E?

A. No. There are no proposed changes to Schedule E.

<u>Schedule G – General Service Non-Demand</u>

Q. What is Schedule G?

A. Schedule G is for general power service applicable to small commercial customers with loads not exceeding 5,000 kWh per month or loads less than or equal to 25 kW.

Q. What are the proposed changes to Schedule G?

A. The following are the proposed changes to Schedule G:

5) increase the Customer Charge from $22.00 to $30.00 per month for Single-Phase service, and from $38.00 to $45.00 per month for Three-Phase service;

6) increase the Energy Charge from 20.4188 ¢/kWh to 35.4062 ¢/kWh;

7) increase the Minimum Charge from $27.00 to $35.00 per month for Single-Phase service, and from $43.00 to $50.00 per month for Three-Phase service; and

8) change the Primary Supply Voltage Service from 2.0% to 1.1% for distribution primary (DP) customers, and from 1.0% to 0.5% for distribution secondary (DS) customers.

The proposed changes to Schedule G are designed to produce the proposed allocated class revenue requirements of $763,400 as shown in MECO-1817.

Q. How did you determine the proposed customer charge for Single-Phase and Three-Phase Service?

A. The proposed customer charges are designed to recover about 70% of the Schedule G customer cost of service, which is about the same as the level from the final rate design in MECO's test year 1999 rate case.

Q. How are the proposed minimum charges for Single-Phase and Three-Phase service determined?

A. The proposed minimum charges maintain the $5.00 difference between customer

charges and minimum charges that are contained in existing rates.

Q. How is the proposed Energy Charge of 35.4062 ¢/kWh determined?

A. The proposed Energy Charge of 35.4062 ¢/kWh recovers the remainder of the class' allocated revenue requirements at proposed rates that are not recovered from the proposed customer charges and minimum charges. This includes all of the class' energy costs and the remainder of the class' allocated fixed costs.

Q. How are the proposed changes to the Primary Supply Voltage adjustments determined?

A. The proposed changes to the Primary Supply Voltage adjustments are based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule G customers?

A. MECO-1820 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule J – General Service Demand

Q. What is Schedule J?

A. Schedule J is for general power service applicable to commercial customers with loads greater than 5,000 kWh per month or greater than 25 kW. The current Schedule J allows commercial customers to change service from Schedule J to any of the applicable large power service (Schedule P). The proposed modification to Schedule J's Availability Clause is to clarify the load limits for the medium-sized commercial customers that qualify for service under Schedule J.

Q. What are the proposed changes to Schedule J?

A. The following are the proposed changes to Schedule J:

1. increase the Customer Charge from $35.00 to $45.00 per month for Single-Phase service, and from $50.00 to $60.00 per month for Three-Phase service;
2. increase the Demand Charge from $5.75 to $9.00 per kW;
3. increase the Energy Charge for the three load factor blocks from 20.6089 ¢/kWh, 19.4319 ¢/kWh, and 16.4719 ¢/kWh to 34.9321 ¢/kWh, 33.7551 ¢/kWh, and 30.7951 ¢/kWh, respectively;
4. change the Availability Clause to clarify the current load thresholds and to add a maximum qualifying load less than 200 kW to new customers, and add a clause that would allow customers with loads equal or greater than 200 kW currently receiving service under Schedule J to remain under Schedule J;
5. change the demand ratchet in determining the billing demand under the Determination of Demand provision from the current 75% ratchet to the average demand ratchet; and
6. change the supply voltage adjustments in the Primary Supply Voltage Service provision from 2.0% to 1.1% for distribution primary supply voltage (DP adj.), and from 1.0% to 0.5% for distribution secondary supply voltage (DS adj.).

The proposed changes to Schedule J rates are designed to produce the proposed allocated class' revenue requirements of $2,372,600 as shown in MECO-1817.

Q. How are the proposed customer charges of $45.00 and $60.00 per month for Single-Phase and Three-Phase service, respectively, determined?

A. The proposed customer charges recover about 70% of the customer cost shown in

the cost of service study, which is about the same as the percentage recovery in current rates.

Q. How is the proposed demand charge of $9.00 per kW determined?

A. The proposed demand charge of $9.00 per kW is based on about 33% of the class's full unit demand cost. In the existing rates, the Schedule J demand charge recovers about 17% of the demand cost. MECO proposes to increase the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service.

Q. How are the proposed energy charges determined?

A. The proposed energy charges the three load factor blocks are designed to recover all of the class's allocated energy costs as well as the remaining customer-related and demand-related costs that are not recovered in the proposed customer and demand charges. The proposed energy charges are approximately the same rate increase in cents per kWh in each energy charge block.

Q. Why is the Company proposing a maximum qualifying load of less than 200 kW for Schedule J?

A. MECO's proposal to define a maximum qualifying load under Schedule J is based on the following reasons:

1. to better define and clarify the load size that qualifies under Schedule J for ease of understanding and application;
2. to make a clearer distinction between the medium-sized customers served under Schedule J, and the large power customers served under the Schedule P;
3. to apply Schedule J to a more homogenous group of medium-size commercial and industrial customers with similar load levels and

characteristics, essential for designing more efficient pricing and costing, and facilitate aligning rates closer to cost of service; and

4. to support rate and revenue stability and continuity.

Q. Will customers currently served under Schedule J with loads equal to or greater than 200 kW be allowed to stay on Schedule J?

A. Yes. These customers will be grandfathered and can remain to be served under Schedule J, if they chose. The new proposed maximum qualifying load under Schedule J will apply to new customers.

Q. Why is MECO proposing to change Schedule J's demand ratchet?

A. MECO is proposing to change Schedule J's demand ratchet for determining the billing kW from the current 75% ratchet to average demand ratchet for simplicity and ease of understanding. The proposed average demand ratchet is the same as the current demand ratchet in Schedule P, making the demand ratchet provisions for all the demand rate schedules the same and consistent. The average demand ratchet compares the customer's maximum demand for the current billing period with the average of his current maximum demand and his maximum demand for the last 11 months, as well as with Schedule J's minimum billing demand of 25 kW – in determining the customer's billing kW demand. The customer's demand charge is based on the highest of these three demand values.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments for distribution primary supply voltage and distribution secondary supply voltage is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule J customers?

A. MECO-1820 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule H – Commercial Cooking, Heating, Air Conditioning, and Refrigeration Service

Q. What is Schedule H?

A. Schedule H is an end-use rate that applies to specific commercial electric loads including commercial cooking, heating, air conditioning, and refrigeration loads that are less than 600 volts.

Q. What are the proposed changes to Schedule H?

A. The following are the proposed changes to Schedule H:

1. increase the Customer Charge from $27.00 to $40.00 per month for Single-Phase service, and from $43.00 to $55.00 per month for Three-Phase service;
2. increase the Demand Charge from $4.50 per kWb to $8.00 per kWb;
3. increase the Energy Charge from 18.0021 ¢/kWh to 32.8358 ¢/kWh; and
4. close the rate schedule to new customers.

The proposed changes to Schedule H are designed to produce the class's total allocated revenue requirements of $190,000 as shown in MECO-1817.

Q. How are the proposed customer charge of $40.00 per month for Single-Phase service and $55.00 per month for Three-Phase service determined?

A. The proposed customer charges recover about 70% of the customer cost shown in the cost of service study, which is less than the percentage recovery in current rates.

Q. How is the proposed demand charge of $8.00 per kW determined?

A. The proposed demand charge of $8.00 per kW is based on about 10% of the class's full unit demand cost, compared to the current demand charge's recovery of about 10% of current demand cost. MECO proposes to increase the amount of demand costs recovered by demand charges in the future, which is also a movement towards aligning rates with the cost of service.

Q. How did you determine the proposed Energy Charge?

A. The proposed energy charge is based on recovering the class's total allocated energy-related and demand-related costs as well as the remaining customer-related costs that are not recovered from the proposed customer charge.

Q. Why is MECO proposing to close Schedule H to new customers?

A. With the proposals to define kW limits in Schedules J and P, MECO is moving towards clearer distinctions between its commercial customers. The number of Schedule H customers is relatively small compared to the number of Schedules G, J, or P customers. MECO would like to close the Schedule H to new customers in order to plan for a transition for the existing Schedule H customers. The same proposal has been advanced in the open HELCO and HECO rate cases.

Q. Does that mean that no customer can have new Schedule H service?

A. The Company proposes that there will be no new Schedule H service connections, with the exception of allowing customers with existing Schedule H service to re-locate their Schedule H service. That is, a customer who terminates Schedule H service in one location will be allowed to contemporaneously open a new Schedule H service in another service location. There is no net gain of Schedule H customers in this situation.

Q. What is the impact of the proposed changes to Schedule H customers?

A. MECO-1820 compares the commercial electric bills under the present rates and

proposed rates for various consumption levels.

Schedule P – Large Power Service

Q. What is Schedule P?

A. Schedule P is for general power service applicable to commercial or industrial customers with large power loads of at least 200 kW.

Q. What are the proposed changes to Schedule P?

A. The following are the proposed changes to Schedule P:

1. increase the Demand Charge for the two demand blocks from $8.50 per kW and $8.00 per kW to $22.00 and $20.00 per kW, respectively;
2. increase the Energy Charge for the three load factor blocks from 18.8358 ¢/kWh, 17.2958 ¢/kWh, and 15.5858 ¢/kWh, to 32.1715 ¢/kWh, 30.6315 ¢/kWh, and 28.9215 ¢/kWh, respectively; and
3. change the service voltage adjustments in the Supply Voltage Delivery provision from the current 4.9%, 3.9%, 2.0%, and 1.0% for transmission primary, transmission secondary, distribution primary, and distribution secondary, to 4.4 %, 3.8%, 1.1%, and 0.5 %, respectively.

The proposed changes to Schedule P rates are designed to produce the proposed allocated class' revenue requirements of $4,356,900 as shown in MECO-1817.

Q. Please explain how you determined the proposed demand charges?

A. The proposed demand charge for the first demand block is designed to recover approximately 26% of the class's unit demand cost, compared to about 17% recovery in existing rates. MECO proposes to increase the amount of demand costs recovered by demand charges, which is also a movement towards aligning

rates with the cost of service. The proposed demand charge for the 2nd demand block recovers about 24% of demand cost.

Q. How are the proposed energy charges determined?

A. The proposed energy charges are based on recovering the class's proposed allocated total revenue requirements less the revenues recovered from the proposed customer and demand charges. This includes the entire energy-related costs (or variable costs) and the remainder of the customer-related costs and the demand-related costs (or fixed costs) that are not recovered from the proposed customer and demand charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule P energy block rates.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments for distribution primary supply voltage and distribution secondary supply voltage is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule P customers?

A. MECO-1820 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

<u>Schedule F – Public Street Lighting</u>

Q. What is Schedule F?

A. Schedule F is for public street and highway lighting.

Q. What are the proposed changes to Schedule F?

A. The following are the proposed changes to Schedule F:

2) increase the energy charge for the two load factor blocks from the current 21.0335 ¢/kWh and 16.5415 ¢/kWh to 36.8235 ¢/kWh and 32.3315 ¢/kWh, respectively.

The proposed changes to Schedule F rates are designed to produce the proposed allocated class' revenue requirements of $38,800, as shown in MECO-1817.

Q. Please explain how you derived the proposed energy charges for the two load factor blocks?

A. Like Schedule R and Schedule G, the proposed energy rates for Schedule F are determined to recover the remainder of the class' allocated revenue requirements at proposed rates that are not recovered in the proposed customer and minimum charges. This includes the class's entire energy cost and the remainder of the customer and demand costs that are not recovered in the proposed customer and minimum charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule F energy block rates.

Q. What is the impact of the proposed changes to Schedule F customers?

A. MECO-1820 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule U – Time-of-Use Service

Q. What is Schedule U?

A. Schedule U is an optional Time-of-Use Service for commercial or industrial customers with loads of at least 25 kW. Customers who qualify for service under Schedule J or P can elect to be served under Schedule U.

Schedule U provides an on-peak demand charge and time-differentiated energy rates. For instance, the demand charge is applied only to kW load used during the on-peak period, and the energy rates are differentiated by the time-of-use rating periods. Service under Schedule U is based on customer election.

Q. What are the proposed changes to Schedule U?

A. The proposed changes to Schedule U include the following:

3) increase the Energy Charge from the current 20.6089 ¢/kWh for the on-peak period to 34.9321 ¢/kWh, and from 15.5858 ¢/kWh for the off-peak period to 28.9215 ¢/kWh;

4) change the service voltage adjustments in the Supply Voltage Delivery provision from the current 4.9%, 3.9%, 2.0%, and 1.0% for transmission primary, transmission secondary, distribution primary, and distribution secondary, to 4.4 %, 3.8%, 1.1%, and 0.5 %, respectively; and

3) close the Schedule to new customers.

Q. How did you determine the proposed time-of-use energy rates for Schedule U?

A. The proposed On-Peak Energy Rate of 34.9321 ¢/kWh is the same as the first block energy rate in the proposed Schedule J charges, and the proposed Off-Peak Energy Rate of 28.9215 ¢/kWh is the same as the third block energy rate in the proposed Schedule P charges. This is the same derivation that was used in test year 1999 to set the existing Schedule U rates.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. Why is the Company proposing to close Schedule U to new customers?

A. There are no customers currently receiving Schedule U service. The Company wants to target the time-of-use rate options to specific classes of customers. The Company proposes in this docket to offer a time-of-use option only for Schedule J customers (TOU-J) and a time-of-use option only for Schedule P customers (TOU-P), rather than have one rate option (Schedule U) try to serve both classes of customers. A discussion of the Company's new time-of-use proposals follows below.

Rider T – Time-of-Day Rider

Q. What is Rider T?

A. Rider T is an optional time-of-use service rider for commercial or industrial customers with power loads of at least 25 kW who are served under Schedule J, or Schedule P. Rider T modifies or provides adjustments to the applicable rate schedule's demand and energy rates, which effectively results in time-of-use price signals. It was aimed at encouraging customers to manage their loads in order to help reduce the system peak load and defer the need for the next capacity addition.

Q. Is MECO proposing any changes to the Rider T?

A. Yes. MECO is proposing the following changes to Rider T:

1. add terms and conditions that would allow customers to do emergency maintenance on their equipment without considering its impact on the customers' maximum on-peak demand in the determination of their billing demand.

Rider M – Off-Peak and Curtailable Service

Q. What is Rider M?

A. Rider M is an optional off-peak and Curtailable service applicable to Schedule J customers with loads greater than 100 kW, and to customers served under Schedule P with loads greater than 300 kW. Rider M provides load management incentives to customers by modifying the determination of the billing demand under Schedules J or P. It offers two load management service options: Option A – Off-Peak Service, and

Option B – Curtailable Service.

The Rider M – Off-Peak Service (Option A) encourages customers to shift their load to the off-peak hours by basing the determination of the billing demand only on the customers' kW demand during the on-peak period. The Rider M – Curtailable Service (Option B) encourages customers to shift their load to off-peak hours by reducing the customers' billing demand by 75% of the kW load that they curtail during the Company's priority peak period, or by 40% of the kW load that they curtail for a two-hour duration specified by the Company.

Q. Is MECO proposing any changes to Rider M?

A. Yes. The following are the proposed changes to Rider M:

1. modify the Availability Clause to appropriately reference the new Schedule TOU-J and Schedule TOU-P.

<u>Rider I – Interruptible Contract Service</u>

Q. What is Rider I?

A. Rider I is an optional interruptible service available to large power customers with interruptible kW load of at least 500 kW.

Q. Did MECO propose any changes to Rider I?

A. No, no changes are proposed.

Schedule Q – Purchases from Qualifying Facilities 100 kW or Less

Q. What is Schedule Q?

A. Schedule Q applies to customers with small production facilities with design capacity of 100 kW or less, qualifying under Chapter 74, Title 6 of the PUC Rules, and who have a purchase power contract with the Company. Schedule Q provides the energy rates and energy cost adjustment that the Company pays for energy purchased by the Company from the customer, and the metering charge to the customer for metering, billing and administration of the purchase power contract.

Q. Are there proposed changes to Schedule Q?

A. Yes. The following are the proposed changes to Schedule Q:

3) change the Energy Rates for energy delivered to the Company by the customer from the current 8.74 ¢/kWh to 21.81 ¢/kWh; and

4) change the generation base fuel cost from the current 773.27 ¢/mbtu to 1,960.44 ¢/mbtu.

Q. How was the proposed energy rate of 21.81 ¢/kWH for energy delivered to MECO determined?

A. The proposed energy rate of 21.81 ¢/kWh for energy delivered by the customer to MECO is based on the test-year estimates of the Company's generation cost and Distributed Generation cost and efficiency factors discussed in MECO T-4.

Q. What is the basis of the changes to Schedule Q's Energy Cost Adjustment Clause?

A. The proposed 1,960.44 ¢/mbtu in Schedule Q's Energy Cost Adjustment Clause is based on the test-year estimate of the total composite generation cost including Distributed Generation costs and discussed in MECO T-19. The test-year fuel

price and efficiency factors used to determine this composite generation cost are discussed in MECO T-4.

Energy Cost Adjustment Clause

Q. What is the Energy Cost Adjustment Clause?

A. The Energy Cost Adjustment Clause (ECAC) is a reconciliation mechanism that allows the Company to recover or refund the difference between the fuel price embedded in the base rates and the fuel price that it actually pays.

Q. What are the proposed changes to ECAC?

A. The following are the proposed changes to ECAC:

1. modify the ECAC's Applicability Clause to include the new Schedule TOU-R, Schedule TOU-G, Schedule TOU-J, and Schedule TOU-P;
2. change the base fuel cost for Company generation from the current 1,067.32 ¢/mbtu to 1,960.44 ¢/mbtu Company composite cost of generation from central station and other generation;
3. change the Company generation efficiency factor from the current 0.010678 mmbtu/kWh to use three separate efficiency factors, 0.010577 mmbtu/kWh for industrial fuel oil (IFO), 0.010577 mmbtu/kWh for diesel fuel, and 0.010577 mmbtu/kWh for other company generation sources;
4. add a distributed generation (DG) energy component in the Clause at 19.673 cents per kWh, adjusted to the sales delivery level and for revenue taxes; and
5. change the base purchased energy cost from the current 7.695 ¢/kWh

to 19.673 ¢/kWh.

Q. How are the proposed changes to the above ECAC parameters determined?

A. The proposed changes to the base fuel costs, generation efficiency factors, DG energy component, and base purchased energy cost are discussed in MECO T-4. The ECAC calculations are presented in MECO T-19.

Integrated Resource Planning Cost Recovery Provision

Q. What is the Integrated Resource Planning Cost Recovery Provision ("IRP Clause")?

A. The IRP Clause is a cost recovery mechanism for the incremental costs incurred by the Company related to incremental IRP-related activities, and the recovery of the incremental DSM costs which include program costs (excluding base labor), lost margin and shareholder incentives.

Q. Does the Company still require an IRP clause?

A. Yes. The Company will have to retain the IRP clause for use in reconciling the recovery of the 1995-2005 IRP costs that MECO already recovered per stipulated agreement with the CA subject to refund with interest, with the amounts of such costs that the PUC would ultimately find reasonable and allow MECO to recover. Additionally, MECO will also use the current IRP clause to recover DSM program costs that are approved for recovery by the Commission.

Green Pricing Program Provision

Q. What is the Green Pricing Program Provision?

A. The Green Pricing Program Provision is a voluntary fund-raising program that is open to Island residents and non-residents for purposes of funding the

development of renewable energy facilities on the Island. The voluntary contributions received from this Green Pricing Program have been used for such programs as the Sun Power for Schools Pilot Program which funds the installation of photovoltaic systems in public schools.

Q. Are there changes proposed to the Green Pricing Program?

A. No. There are no changes proposed to the Green Pricing Program.

New Rate Schedules

Q. Is MECO proposing any new rate schedules for Lanai Division?

A. Yes. MECO is proposing four new rate schedules for Lanai Division:

1. Schedule TOU-R – Residential Time-of-Use Service;
2. Schedule TOU-G – Small Commercial Time-of-Use Service;
3. Schedule TOU-J – Commercial Time-of-Use Service; and
4. Schedule TOU-P – Large Power Time-of-Use Service.

Optional Time-of-Use Service Rate Schedules

Q. Please describe the goals of offering four new time-of-use rate options in this case.

A. The Company proposes to offer four new time-of-use rate options in this case, Schedule TOU-R – Residential Time-of-Use Service, Schedule TOU-G – Small Commercial Time-of-Use Service, Schedule TOU-J – Commercial Time-of-Use Service, and Schedule TOU-P – Large Power Time-of-Use Service, in order to extend to all customers the opportunity to choose time-of-use rates, to establish a consistency in rate design for all time-of-use rate options, and to manage participation and collect data for future time-of-use rate designs. Making time-of-use rate options available to all customers, with the exception of street

light customers, is consistent with the approach taken in the recent HECO rate cases, Docket No. 04-0113 and Docket No. 2006-0386, as well as in HELCO's test year 2006 rate case, Docket No. 05-0315. It is consistent with the goals of the Energy Policy Act of 2005. The proposed time-of-use rate options have consistent time-of-use rating periods (priority peak, mid-peak, and off-peak periods) and consistent rate designs (demand charge based on priority peak and mid-peak, no demand ratchet, separate energy charges for each rating period). The time-of-use rate options are intended to create lower electric bills for customers who modify their existing energy consumption patterns. The Company proposes to manage participation in these optional rates while collecting data for future time-of-use rate design offerings by setting a limit on the number of meters that can participate in certain optional rate schedules. The meter limit facilitates effective implementation of these rate options since the current billing system cannot bill time-of-use rates automatically, and in case the new Customer Information System (CIS) is not yet in place by the time these proposed rates are approved. In addition, the Company has not estimated any revenue adjustment for customer participation in these time-of-use rate options, so the meter limit helps to mitigate any negative revenue impact that the Company might experience in implementing these rate options.

<u>Schedule TOU-R – Residential Time-of-Use Service</u>

Q. Please describe MECO's proposed Schedule TOU-R for Lanai Division.

A. Customers currently served under Schedule R are eligible to elect time-of-use service under Schedule TOU-R. The proposed Schedule TOU-R has the following parameters:

1. Customer Charge: $7.50 per month for Single-Phase Service, and $12.00 per month for Three-Phase service;
2. Energy Charge: Calculated in the same manner and at the same rates as the proposed Schedule R, with the following time-of-use energy rate adjustments:

Priority Peak Period kWh use	+ 5.0 ¢ per kWh,
Mid-Peak Period kWh use	+ 2.5 ¢ per kWh, and
Off-Peak Period kWh use	- 5.0 ¢ per kWh;

3. Minimum Bill is the same as proposed for Schedule R;
4. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily; and

5. Service is limited to a maximum of 300 meters across all three MECO divisions.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $7.50 for Single-Phase Service and $12.00 for Three-Phase Service are the same as the proposed customer charges for Schedule R.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate adjustment for all kWh used in the priority peak period of + 5.0 ¢/kWh is based on 250% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate

adjustment for all kWh used in the mid-peak period of +2.5 ¢/kWh is based on 125% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period is based on about 170% of the existing off-peak energy credit for Rider T customers. However, even at the lowest energy tier, the effective off-peak kWh rate on Schedule TOU-R exceeds the off-peak marginal energy cost rate for 2007, and therefore makes a contribution towards fixed cost recovery.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-R are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Schedule TOU-G – Small Commercial Time-of-Use Service

Q. Please describe HELCO's proposed Schedule TOU-G for Lanai Division.

A. Customers currently served under Schedule G are eligible to elect time-of-use service under Schedule TOU-G. The proposed Schedule TOU-G has the following parameters:

1. Customer Charge: $30.00 per month for Single-Phase Service, and $45.00 per month for Three-Phase service;
2. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	40.4062 ¢ per kWh,
Mid-Peak Period kWh use	37.9062 ¢ per kWh, and
Off-Peak Period kWh use	30.4062 ¢ per kWh;

3. Minimum Bill is the same as the proposed Schedule TOU-G customer charge;

4. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily; and

5. Service is limited to a maximum of 100 meters across all three MECO divisions.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $30.00 for Single-Phase Service and $45.00 for Three-Phase Service are the same as the proposed customer charges for Schedule G.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 40.4062 ¢/kWh is based on the proposed Schedule G energy rate plus 250% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 37.9062 ¢/kWh is based on the proposed Schedule G energy rate plus 125% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 30.4062 ¢/kWh is based on the proposed Schedule G energy rate less about 170% of the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-G exceeds the off-peak marginal energy cost rate for 2007, and therefore makes a contribution towards fixed cost recovery.

Q. Are these time-of-use rating periods the same as currently used in MECO's

existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-G are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Schedule TOU-J – Commercial Time-of-Use Service

Q. *Please describe MECO's proposed Schedule TOU-J for Lanai Division.*

A. Customers currently served under Schedule J are eligible to elect time-of-use service under Schedule TOU-J. The proposed Schedule TOU-J has the following parameters:

1. Customer Charge: $55.00 per month for Single-Phase Service, and $70.00 per month for Three-Phase service;
2. Demand Charge of $13.50 per kW if customer's maximum demand occurs during the priority peak period and $9.00 per kW if it occurs during the mid-peak period.
3. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	40.4946 ¢ per kWh,
Mid-Peak Period kWh use	38.4946 ¢ per kWh, and
Off-Peak Period kWh use	28.4946 ¢ per kWh;

4. Minimum Bill is the same as proposed for Schedule J, the sum of the Customer Charge and the Demand Charge; and
5. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $55.00 for Single-Phase Service and $70.00 for Three-Phase Service are based on the proposed customer charges for Schedule J, plus an additional $10.00 per month, which is the same as the current time-of-use meter charge in Rider T and Rider M.

Q. Please explain the proposed demand charge for Schedule TOU-J.

A. The proposed demand charge under Schedule TOU-J is based on the customer's maximum measured kW demand for the billing period. The Company is not proposing a demand ratchet in the determination of the billing demand – the same as in the current Schedule U. However, the minimum billing demand of 25 kW still applies. If the customer's maximum measured kW demand for the billing period occurs during the priority peak hours, the priority peak demand charge of $13.50 per kW is applied. If the customer's maximum measured kW demand for the billing period occurs during the mid-peak hours, the mid-peak demand charge of $9.00 per kW is applied. In other words, a customer is charged either the $13.50 per kW Priority Peak demand charge or the $9.00 per kW Mid-Peak demand charge based on when his maximum kW demand occurs. There is no demand charge for kW load during the off-peak hours. The determination of demand provision in the proposed Schedule TOU-J specifies the application of the proposed demand charge.

Q. How did you determine the proposed priority peak demand charge and the mid-peak demand charge?

A. The proposed demand charge of $13.50 per kW for the priority peak period is based on recovering approximately 50% of full unit demand cost for Schedule J at

proposed rates. The proposed demand charge of $9.00 per kW for mid-peak period is the same as the proposed demand charge for Schedule J.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 40.4946 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates plus 300% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 38.4946 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates plus 200% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 28.4946 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates less about 200% of the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-J exceeds the off-peak marginal energy cost rate for 2007.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-J are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

<u>Schedule TOU-P – Large Power Time-of-Use Service</u>

Q. Please describe MECO's proposed Schedule TOU-P for Lanai Division.

A. Customers currently served under Schedule P are eligible to elect time-of-use service under Schedule TOU-P. The proposed Schedule TOU-P has the following parameters:

1. Customer Charge: $210.00 per month;

2. Demand Charge of $42.00 per kW if customer's maximum demand occurs during the priority peak period and $22.00 per kW if it occurs during the mid-peak period.
3. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	36.8390 ¢ per kWh,
Mid-Peak Period kWh use	34.8390 ¢ per kWh, and
Off-Peak Period kWh use	24.8390 ¢ per kWh;

4. Minimum Bill is the same as proposed for Schedule P, the sum of the Customer Charge and the Demand Charge; and
5. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily.

Q. How did you determine proposed customer charge?

A. The proposed customer charge of $210.00 per month is based on the proposed customer charge for Schedule P, plus an additional $10.00 per month, which is the same as the current time-of-use meter charge in Rider T and Rider M.

Q. Please explain the proposed demand charge for Schedule TOU-P.

A. The proposed demand charge under Schedule TOU-P is based on the customer's maximum measured kW demand for the billing period. The Company is not proposing a demand ratchet in the determination of the billing demand – the same as in the current effective Schedule U. However, the minimum billing demand of 200 kW still applies. If the customer's maximum measured kW demand for the billing period occurs during the priority peak hours, the priority peak demand

charge of $42.00 per kW is applied. If the customer's maximum measured kW demand for the billing period occurs during the mid-peak hours, the mid-peak demand charge of $22.00 per kW is applied. In other words, a customer is charged either the $42.00 per kW Priority Peak demand charge or the $22.00 per kW Mid-Peak demand charge based on when his maximum kW demand occurs. There is no demand charge for kW load during the off-peak hours. The determination of demand provision in the proposed Schedule TOU-P specifies the application of the proposed demand charge.

Q. How did you determine the proposed priority peak demand charge and the mid-peak demand charge?

A. The proposed demand charge of $42.00 per kW for the priority peak period is based on recovering approximately 50% of full unit demand cost for Schedule P at proposed rates. The proposed demand charge of $22.00 per kW for mid-peak period is the same as the proposed demand charge for the first kW tier on Schedule P.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 36.8390 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates plus 300% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 34.8390 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates plus 200% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 24.8390 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates less about 200% of

the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-P exceeds the off-peak marginal energy cost rate for 2007.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-P are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Standby Charge

Q. Are there any other proposed new rates?

A. Pursuant to Decision and Order No. 22248 in Docket No. 03-0371 on Distributed Generation, the Company proposed Standby Rates for Maui, Lanai, and Molokai Divisions. The proposed Standby Rates will be reviewed in a separate proceeding, Docket No. 2006-0497, pursuant to the Commission's Order No. 23171.

Electric Vehicle Charging Rates

Q. Is MECO proposing to terminate any existing rate schedule or rate adjustment for Maui Division?

A. Yes. MECO is proposing to withdraw the Rider EV-R – Residential Electric Vehicle Charging Service, Rider EV-C – Commercial Electric Vehicle Charging Service. MECO is also terminating the Firm Capacity Surcharge refund for the termination of capacity payments to Pioneer Mill. This reduction in capacity payments is reflected in the test-year estimates of the purchased power expense and embedded in the new proposed rate changes.

Q. Why is MECO proposing to withdraw Riders EV-R and EV-C?

A. HECO's Rider EV-R and Rider EV-C became effective on July 6, 1998. On August 13, 1998, HECO agreed to defer implementation of the riders per Commission's request in an August 3, 1998 letter. HECO has not received PUC approval to implement these riders, although they remained in MECO's current effective rates.

More importantly, MECO's proposed Schedule TOU-R, Schedule TOU-G, Schedule TOU-J, and Schedule TOU-P will also apply to electric vehicle charging service. These proposed new Schedules will provide time-of-use service to electric vehicle charging without the need to separately meter these loads from the rest of the customers' electric loads, as required under the Rider EV-R and Rider EV-C, which were available only for the electric vehicle charging load.

MOLOKAI DIVISION RATE DESIGN PROPOSAL

Q. What are the proposed changes to Molokai Division existing rates?

A. The proposed rate design changes to each Molokai Division rate schedule are summarized below:

Schedule R – Residential Service

Q. What is Schedule R?

A. Schedule R is for residential electric service applicable to individually metered residential dwelling units.

Q. What are the proposed changes to Schedule R?

A. The following are the proposed changes to Schedule R:

1. increase the Base Fuel Energy Charge from 5.3991 ¢/kWh to 21.7788 ¢/kWh; and

2. change the Non-Fuel Energy Charge from 12.0392 ¢/kWh to three tiers, 12.5944 ¢/kWh for the first 250 kWh, 13.7500 ¢/kWh for the next 500 kWh, and 14.0055 ¢/kWh for all kWh over 750 kWh per billing period.

The proposed changes to Schedule R are designed to produce the proposed allocated class revenue requirements of $4,796,900 as shown in MECO-1818.

Q. How is the proposed Base Fuel Energy Charge determined?

A. The proposed Base Fuel Charge of 21.7788 ¢/kWh is based on the test-year composite fuel price for base generation, base purchase power, and base cost of fuel for MECO's distributed generation units. See the calculation of the Base Fuel Energy Charge in MECO-1814.

Q. What are the merits of the proposed inclining block rate design for Non-Fuel Energy Charges?

A. The merits on an inclining block rate design include mitigation of rate impact on the smallest users of the system, pricing signals that encourage conservation, and assignment of a greater share of the cost increase to the larger users. HELCO has made a similar proposal for Schedule R in Docket No. 05-0315, its 2006 test year rate case, and HECO also has such a proposal in Docket No. 2006-0386, its 2007 test year rate case.

Q. Does the inclining block rate design address the challenges facing low income residential ratepayers?

A. The inclining block rate design does benefit most residential ratepayers, including low income residential ratepayers, by offering a lower electricity price for the initial kWh of usage. However, the Company recognizes that the rate design alone does not fully address the challenges facing low income residents whose

usage extends beyond the boundary of the first tier. The Company plans to develop a program to address the issues of low income residential ratepayers, and plans to introduce its proposal subsequently in this case.

Q. What are the features of the inclining block rate proposal for the proposed Non-Fuel Energy Charges?

A. The features are three tiers, one for the first 250 kWh used in the billing period, one for the next 500 kWh used in the billing period, or kWh usage between 250 kWh and 750 kWh, and a third tier for kWh usage above 750 kWh per billing period. Each tier has a different non-fuel energy charge per kWh, with the first 250 kWh having the lowest proposed non-fuel energy charge and kWh usage over 750 kWh having the highest proposed non-fuel energy charge.

Q. How were the sizes of the kWh tiers determined?

A. The first tier, up to 250 kWh, was set to provide the lowest energy rate for a base kWh usage level. The second tier, from 250 kWh to 750 kWh, was to set to capture the majority of the kWh. As shown in MECO-1815, about 31% of customer bills fall into the lowest tier, 55% of customer bills fall into the middle tier, and 14% of the customer bills fall into the highest tier. However, approximately 90% of all kWh will be billed at either the first or second tier rate. The tiers are designed so that most of the usage is covered by the first two tiers and only the very highest residential customer usage will incur the third tier energy charges.

Q. How were the Non-Fuel Energy Charges for the kWh tiers determined?

A. The guidelines used to determine the non-fuel energy charges for the kWh tiers were to collect the demand and customer costs that are not recovered by the customer and minimum charges, to target approximately a 2% to 3% bill increase

for customers whose billing quantities fell into the first tier only, and to target no more than approximately the class average increase, 5.3%, for customers whose billing quantities fell into the first and second tiers. Note that the proposed rate increase for billing quantities up to 250 kWh ranges up to 3.2%, the proposed rate increase for billing quantities between 250 kWh and 750 kWh ranges between 3.2% and 5.6%, and the proposed rate increase for billing quantities above 750 kWh ranges between 5.6% and 7.7% compared to present rates.

Q. What is the impact of the proposed changes to Schedule R on the residential customers?

A. MECO-1821 compares the residential electric bills under the present rates and proposed rates for various consumption levels.

Schedule E – Electric Service for Employees

Q. What is Schedule E?

A. Schedule E is for electric residential service for Company employees and retirees, and members of the Company's Board of Directors.

Q. Are there any changes to Schedule E?

A. No. There are no proposed changes to Schedule E.

Schedule G – General Service Non-Demand

Q. What is Schedule G?

A. Schedule G is for general power service applicable to small commercial customers with loads not exceeding 5,000 kWh per month or loads less than or equal to 25 kW.

Q. What are the proposed changes to Schedule G?

A. The following are the proposed changes to Schedule G:

1. increase the Customer Charge from $22.00 to $23.00 per month for Single-Phase service, and from $33.00 to $34.00 per month for Three-Phase service;
2. increase the Energy Charge from 23.7929 ¢/kWh to 41.7728 ¢/kWh;
3. increase the Minimum Charge from $27.00 to $28.00 per month for Single-Phase service, and from $38.00 to $39.00 per month for Three-Phase service; and
4. change the Primary Supply Voltage Service from 2.0% to 1.1% for distribution primary (DP) customers, and from 1.0% to 0.5% for distribution secondary (DS) customers.

The proposed changes to Schedule G are designed to produce the proposed allocated class revenue requirements of $1,793,500 as shown in MECO-1818.

Q. How did you determine the proposed customer charge for Single-Phase and Three-Phase Service?

A. The proposed customer charges are designed to recover about 90% of the Schedule G customer cost of service, which is about the same as the level from the final rate design in MECO's test year 1999 rate case.

Q. How are the proposed minimum charges for Single-Phase and Three-Phase service determined?

A. The proposed minimum charges maintain the $5.00 difference between customer charges and minimum charges that are contained in existing rates.

Q. How is the proposed Energy Charge of 41.7728 ¢/kWh determined?

A. The proposed Energy Charge of 41.7728 ¢/kWh recovers the remainder of the class' allocated revenue requirements at proposed rates that are not recovered

from the proposed customer charges and minimum charges. This includes all of the class' energy costs and the remainder of the class' allocated fixed costs.

Q. How are the proposed changes to the Primary Supply Voltage adjustments determined?

A. The proposed changes to the Primary Supply Voltage adjustments are based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule G customers?

A. MECO-1821 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule J – General Service Demand

Q. What is Schedule J?

A. Schedule J is for general power service applicable to commercial customers with loads greater than 5,000 kWh per month or greater than 25 kW. The current Schedule J allows commercial customers to change service from Schedule J to any of the applicable large power service (Schedule P). The proposed modification to Schedule J's Availability Clause is to clarify the load limits for the medium-sized commercial customers that qualify for service under Schedule J.

Q. What are the proposed changes to Schedule J?

A. The following are the proposed changes to Schedule J:

1. increase the Customer Charge from $30.00 to $32.00 per month for Single-Phase service, and from $40.00 to $42.00 per month for Three-Phase service;
2. increase the Demand Charge from $4.75 to $11.00 per kW;

3. increase the Energy Charge for the three load factor blocks from 19.6204 ¢/kWh, 13.7734 ¢/kWh, and 11.9444 ¢/kWh to 34.7806 ¢/kWh, 28.9336 ¢/kWh, and 27.1046 ¢/kWh, respectively;
4. change the Availability Clause to clarify the current load thresholds and to add a maximum qualifying load less than 100 kW to new customers, and add a clause that would allow customers with loads equal or greater than 100 kW currently receiving service under Schedule J to remain under Schedule J;
5. change the demand ratchet in determining the billing demand under the Determination of Demand provision from the current 75% ratchet to the average demand ratchet; and
6. change the supply voltage adjustments in the Primary Supply Voltage Service provision from 2.0% to 1.1% for distribution primary supply voltage (DP adj.), and from 1.0% to 0.5% for distribution secondary supply voltage (DS adj.).

The proposed changes to Schedule J rates are designed to produce the proposed allocated class' revenue requirements of $2,981,100 as shown in MECO-1818.

Q. How are the proposed customer charges of $32.00 and $42.00 per month for Single-Phase and Three-Phase service, respectively, determined?

A. The proposed customer charges recover about 90% of the customer cost shown in the cost of service study, which is somewhat higher than the percentage recovery in current rates.

Q. How is the proposed demand charge of $11.00 per kW determined?

A. The proposed demand charge of $11.00 per kW is based on about 23% of the

class's full unit demand cost. In the existing rates, the Schedule J demand charge recovers about 11% of the demand cost. MECO proposes to increase the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service.

Q. How are the proposed energy charges determined?

A. The proposed energy charges the three load factor blocks are designed to recover all of the class's allocated energy costs as well as the remaining customer-related and demand-related costs that are not recovered in the proposed customer and demand charges. The proposed energy charges are approximately the same rate increase in cents per kWh in each energy charge block.

Q. Why is the Company proposing a maximum qualifying load of less than 100 kW for Schedule J?

A. MECO's proposal to define a maximum qualifying load under Schedule J is based on the following reasons:

1. to better define and clarify the load size that qualifies under Schedule J for ease of understanding and application;
2. to make a clearer distinction between the medium-sized customers served under Schedule J, and the large power customers served under the Schedule P;
3. to apply Schedule J to a more homogenous group of medium-size commercial and industrial customers with similar load levels and characteristics, essential for designing more efficient pricing and costing, and facilitate aligning rates closer to cost of service; and
4. to support rate and revenue stability and continuity.

Q. Will customers currently served under Schedule J with loads equal to or greater

than 100 kW be allowed to stay on Schedule J?

A. Yes. These customers will be grandfathered and can remain to be served under Schedule J, if they chose. The new proposed maximum qualifying load under Schedule J will apply to new customers.

Q. Why is MECO proposing to change Schedule J's demand ratchet?

A. MECO is proposing to change Schedule J's demand ratchet for determining the billing kW from the current 75% ratchet to average demand ratchet for simplicity and ease of understanding. The proposed average demand ratchet is the same as the current demand ratchet in Schedule P, making the demand ratchet provisions for all the demand rate schedules the same and consistent. The average demand ratchet compares the customer's maximum demand for the current billing period with the average of his current maximum demand and his maximum demand for the last 11 months, as well as with Schedule J's minimum billing demand of 25 kW – in determining the customer's billing kW demand. The customer's demand charge is based on the highest of these three demand values.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments for distribution primary supply voltage and distribution secondary supply voltage is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule J customers?

A. MECO-1821 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule H – Commercial Cooking, Heating, Air Conditioning, and Refrigeration Service

Q. What is Schedule H?

A. Schedule H is an end-use rate that applies to specific commercial electric loads including commercial cooking, heating, air conditioning, and refrigeration loads that are less than 600 volts.

Q. What are the proposed changes to Schedule H?

A. The following are the proposed changes to Schedule H:

1. increase the Demand Charge from $6.00 per kWb to $10.00 per kWb;
2. increase the Energy Charge from 14.0975 ¢/kWh to 30.3625 ¢/kWh; and
3. close the rate schedule to new customers.

The proposed changes to Schedule H are designed to produce the class's total allocated revenue requirements of $677,300 as shown in MECO-1818.

Q. How is the proposed demand charge of $10.00 per kW determined?

A. The proposed demand charge of $10.00 per kW is based on about 27% of the class's full unit demand cost, compared to the current demand charge's recovery of about 16% of current demand cost. MECO proposes to increase the amount of demand costs recovered by demand charges in the future, which is also a movement towards aligning rates with the cost of service.

Q. How did you determine the proposed Energy Charge?

A. The proposed energy charge is based on recovering the class's total allocated energy-related and demand-related costs as well as the remaining customer-related costs that are not recovered from the proposed customer charge.

Q. Why is MECO proposing to close Schedule H to new customers?

A. With the proposals to define kW limits in Schedules J and P, MECO is moving towards clearer distinctions between its commercial customers. The number of Schedule H customers is relatively small compared to the number of Schedules G, J, or P customers. MECO would like to close the Schedule H to new customers in order to plan for a transition for the existing Schedule H customers. The same proposal has been advanced in the open HELCO and HECO rate cases.

Q. Does that mean that no customer can have new Schedule H service?

A. The Company proposes that there will be no new Schedule H service connections, with the exception of allowing customers with existing Schedule H service to re-locate their Schedule H service. That is, a customer who terminates Schedule H service in one location will be allowed to contemporaneously open a new Schedule H service in another service location. There is no net gain of Schedule H customers in this situation.

Q. What is the impact of the proposed changes to Schedule H customers?

A. MECO-1821 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

<u>Schedule P – Large Power Service</u>

Q. What is Schedule P?

A. Schedule P is for general power service applicable to commercial or industrial customers with large power loads of at least 100 kW.

Q. What are the proposed changes to Schedule P?

A. The following are the proposed changes to Schedule P:

1. increase the Demand Charge for the two demand blocks from $5.00

per kW and $4.85 per kW to $11.00 and $10.00 per kW, respectively;

2. increase the Energy Charge for the three load factor blocks from 16.3763 ¢/kWh, 14.2763 ¢/kWh, and 7.1313 ¢/kWh, to 32.3273 ¢/kWh, 30.2273 ¢/kWh, and 23.0823 ¢/kWh, respectively; and
3. change the service voltage adjustments in the Supply Voltage Delivery provision from the current 4.9%, 3.9%, 2.0%, and 1.0% for transmission primary, transmission secondary, distribution primary, and distribution secondary, to 4.4 %, 3.8%, 1.1%, and 0.5 %, respectively.

The proposed changes to Schedule P rates are designed to produce the proposed allocated class' revenue requirements of $2,879,100 as shown in MECO-1818.

Q. Please explain how you determined the proposed demand charges?

A. The proposed demand charge for the first demand block is designed to recover approximately 37% of the class's unit demand cost, compared to about 21% recovery in existing rates. MECO proposes to increase the amount of demand costs recovered by demand charges, which is also a movement towards aligning rates with the cost of service. The proposed demand charge for the 2nd demand block recovers about 34% of demand cost.

Q. How are the proposed energy charges determined?

A. The proposed energy charges are based on recovering the class's proposed allocated total revenue requirements less the revenues recovered from the proposed customer and demand charges. This includes the entire energy-related costs (or variable costs) and the remainder of the customer-related costs and the

demand-related costs (or fixed costs) that are not recovered from the proposed customer and demand charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule P energy block rates.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule P customers?

A. MECO-1821 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule N – Contract Off-Peak and Interruptible Service

Q. What is Schedule N?

A. Schedule N is the special night service that is included with Schedule P for the purpose of estimating revenues.

Q. What are the proposed changes to Schedule N?

A. The following are the proposed changes to Schedule N:

1. increase the Demand Charge from $1.70 per kW to $3.50 per kW;
2. increase the Energy Charge from 7.1313 ¢/kWh to 23.0823 ¢/kWh;
3. change the service voltage adjustments in the Supply Voltage Delivery provision from the current 2.0%, and 1.0% for distribution primary, and distribution secondary, to 1.1%, and 0.5 %, respectively; and
4. close the Schedule to new accounts.

The proposed changes to Schedule N rates are designed to produce the proposed allocated class' revenue requirements of $2,879,100 as shown in MECO-1818.

Q. Please explain how you determined the proposed demand charges?

A. The proposed demand charge is well below the Schedule P demand cost, but the charge for demand is proposed to be doubled, just as in Schedule P.

Q. How is the proposed energy charge determined?

A. The proposed energy charge is the same as the proposed third block energy rate for Schedule P, as it is under current rates.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments for distribution primary supply voltage and distribution secondary supply voltage is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. What is the impact of the proposed changes to Schedule N customers?

A. MECO-1821 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

<u>Schedule F – Public Street Lighting</u>

Q. What is Schedule F?

A. Schedule F is for public street and highway lighting.

Q. What are the proposed changes to Schedule F?

A. The following are the proposed changes to Schedule F:

1. increase the energy charge for the two load factor blocks from the current 20.2685 ¢/kWh and 15.8625 ¢/kWh to 37.9215 ¢/kWh and

33.5155 ¢/kWh, respectively.

The proposed changes to Schedule F rates are designed to produce the proposed allocated class' revenue requirements of $169,400, as shown in MECO-1818.

Q. Please explain how you derived the proposed energy charges for the two load factor blocks?

A. Like Schedule R and Schedule G, the proposed energy rates for Schedule F are determined to recover the remainder of the class' allocated revenue requirements at proposed rates that are not recovered in the proposed customer and minimum charges. This includes the class's entire energy cost and the remainder of the customer and demand costs that are not recovered in the proposed customer and minimum charges. The proposed energy rates for each energy block have approximately the same cents per kWh increase over the current Schedule F energy block rates.

Q. What is the impact of the proposed changes to Schedule F customers?

A. MECO-1821 compares the commercial electric bills under the present rates and proposed rates for various consumption levels.

Schedule U – Time-of-Use Service

Q. What is Schedule U?

A. Schedule U is an optional Time-of-Use Service for commercial or industrial customers with loads of at least 25 kW. Customers who qualify for service under Schedule J or P can elect to be served under Schedule U.

Schedule U provides an on-peak demand charge and time-differentiated energy rates. For instance, the demand charge is applied only to kW load used

during the on-peak period, and the energy rates are differentiated by the time-of-use rating periods. Service under Schedule U is based on customer election.

Q. What are the proposed changes to Schedule U?

A. The proposed changes to Schedule U include the following:

1. increase the Energy Charge from the current 19.6204 ¢/kWh for the on-peak period to 34.7806 ¢/kWh, and from 7.1313 ¢/kWh for the off-peak period to 23.0823 ¢/kWh;
2. change the service voltage adjustments in the Supply Voltage Delivery provision from the current 4.9%, 3.9%, 2.0%, and 1.0% for transmission primary, transmission secondary, distribution primary, and distribution secondary, to 4.4 %, 3.8%, 1.1%, and 0.5 %, respectively; and

3) close the Schedule to new customers.

Q. How did you determine the proposed time-of-use energy rates for Schedule U?

A. The proposed On-Peak Energy Rate of 34.7806 ¢/kWh is the same as the first block energy rate in the proposed Schedule J charges, and the proposed Off-Peak Energy Rate of 23.0823 ¢/kWh is the same as the third block energy rate in the proposed Schedule P charges. This is the same derivation that was used in test year 1999 to set the existing Schedule U rates.

Q. How did you determine the proposed changes to the supply voltage adjustments?

A. The determination of the proposed changes to the supply voltage adjustments is based on the system loss analysis prepared by MECO's Transmission Planning Division in this rate case.

Q. Why is the Company proposing to close Schedule U to new customers?

A. There are no customers currently receiving Schedule U service. The Company

wants to target the time-of-use rate options to specific classes of customers. The Company proposes in this docket to offer a time-of-use option only for Schedule J customers (TOU-J) and a time-of-use option only for Schedule P customers (TOU-P), rather than have one rate option (Schedule U) try to serve both classes of customers. A discussion of the Company's new time-of-use proposals follows below.

Rider T – Time-of-Day Rider

Q. What is Rider T?

A. Rider T is an optional time-of-use service rider for commercial or industrial customers with power loads of at least 25 kW who are served under Schedule J, or Schedule P. Rider T modifies or provides adjustments to the applicable rate schedule's demand and energy rates, which effectively results in time-of-use price signals. It was aimed at encouraging customers to manage their loads in order to help reduce the system peak load and defer the need for the next capacity addition.

Q. Is MECO proposing any changes to the Rider T?

A. Yes. MECO is proposing the following changes to Rider T:

1. add terms and conditions that would allow customers to do emergency maintenance on their equipment without considering its impact on the customers' maximum on-peak demand in the determination of their billing demand.

Rider M – Off-Peak and Curtailable Service

Q. What is Rider M?

A. Rider M is an optional off-peak and Curtailable service applicable to Schedule J

customers with loads greater than 100 kW, and to customers served under Schedule P with loads greater than 300 kW. Rider M provides load management incentives to customers by modifying the determination of the billing demand under Schedules J or P. It offers two load management service options: Option A – Off-Peak Service, and

Option B – Curtailable Service.

The Rider M – Off-Peak Service (Option A) encourages customers to shift their load to the off-peak hours by basing the determination of the billing demand only on the customers' kW demand during the on-peak period. The Rider M – Curtailable Service (Option B) encourages customers to shift their load to off-peak hours by reducing the customers' billing demand by 75% of the kW load that they curtail during the Company's priority peak period, or by 40% of the kW load that they curtail for a two-hour duration specified by the Company.

Q. Is MECO proposing any changes to Rider M?

A. Yes. The following are the proposed changes to Rider M:

1. modify the Availability Clause to appropriately reference the new Schedule TOU-J and Schedule TOU-P.

<u>Rider I – Interruptible Contract Service</u>

Q. What is Rider I?

A. Rider I is an optional interruptible service available to large power customers with interruptible kW load of at least 500 kW.

Q. Did MECO propose any changes to Rider I?

A. No, no changes are proposed.

Schedule Q – Purchases from Qualifying Facilities 100 kW or Less

Q. What is Schedule Q?

A. Schedule Q applies to customers with small production facilities with design capacity of 100 kW or less, qualifying under Chapter 74, Title 6 of the PUC Rules, and who have a purchase power contract with the Company. Schedule Q provides the energy rates and energy cost adjustment that the Company pays for energy purchased by the Company from the customer, and the metering charge to the customer for metering, billing and administration of the purchase power contract.

Q. Are there proposed changes to Schedule Q?

A. Yes. The following are the proposed changes to Schedule Q:

1. change the Energy Rates for energy delivered to the Company by the customer from the current 5.61 ¢/kWh to 20.64 ¢/kWh; and
2. change the generation base fuel cost from the current 467.54 ¢/mbtu to 1,833.50 ¢/mbtu.

Q. How was the proposed energy rate of 20.64 ¢/kWH for energy delivered to MECO determined?

A. The proposed energy rate of 20.64 ¢/kWh for energy delivered by the customer to MECO is based on the test-year estimates of the Company's generation cost and Distributed Generation cost and efficiency factors discussed in MECO T-4.

Q. What is the basis of the changes to Schedule Q's Energy Cost Adjustment Clause?

A. The proposed 1,833.50 ¢/mbtu in Schedule Q's Energy Cost Adjustment Clause is based on the test-year estimate of the total composite generation cost including Distributed Generation costs and discussed in MECO T-19. The test-year fuel price and efficiency factors used to determine this composite generation cost are

discussed in MECO T-4.

Energy Cost Adjustment Clause

Q. What is the Energy Cost Adjustment Clause?

A. The Energy Cost Adjustment Clause (ECAC) is a reconciliation mechanism that allows the Company to recover or refund the difference between the fuel price embedded in the base rates and the fuel price that it actually pays.

Q. What are the proposed changes to ECAC?

A. The following are the proposed changes to ECAC:

1. modify the ECAC's Applicability Clause to include the new Schedule TOU-R, Schedule TOU-G, Schedule TOU-J, and Schedule TOU-P;
2. change the base fuel cost for Company generation from the current 467.54 ¢/mbtu to 1,833.50 ¢/mbtu Company composite cost of generation from central station and other generation;
3. change the Company generation efficiency factor from the current 0.010522 mmbtu/kWh to use three separate efficiency factors, 0.010823 mmbtu/kWh for industrial fuel oil (IFO), 0.010823 mmbtu/kWh for diesel fuel, and 0.010823 mmbtu/kWh for other company generation sources;
4. add a distributed generation (DG) energy component in the Clause at 18.040 cents per kWh, adjusted to the sales delivery level and for revenue taxes; and
5. change the base purchased energy cost from the current 4.448 ¢/kWh to 18.040 ¢/kWh.

Q. How are the proposed changes to the above ECAC parameters determined?

A. The proposed changes to the base fuel costs, generation efficiency factors, DG energy component, and base purchased energy cost are discussed in MECO T-4. The ECAC calculations are presented in MECO T-19.

Integrated Resource Planning Cost Recovery Provision

Q. What is the Integrated Resource Planning Cost Recovery Provision ("IRP Clause")?

A. The IRP Clause is a cost recovery mechanism for the incremental costs incurred by the Company related to incremental IRP-related activities, and the recovery of the incremental DSM costs which include program costs (excluding base labor), lost margin and shareholder incentives.

Q. Does the Company still require an IRP clause?

A. Yes. The Company will have to retain the IRP clause for use in reconciling the recovery of the 1995-2005 IRP costs that MECO already recovered per stipulated agreement with the CA subject to refund with interest, with the amounts of such costs that the PUC would ultimately find reasonable and allow MECO to recover. Additionally, MECO will also use the current IRP clause to recover DSM program costs that are approved for recovery by the Commission.

Green Pricing Program Provision

Q. What is the Green Pricing Program Provision?

A. The Green Pricing Program Provision is a voluntary fund-raising program that is open to Island residents and non-residents for purposes of funding the development of renewable energy facilities on the Island. The voluntary

contributions received from this Green Pricing Program have been used for such programs as the Sun Power for Schools Pilot Program which funds the installation of photovoltaic systems in public schools.

Q. Are there changes proposed to the Green Pricing Program?

A. No. There are no changes proposed to the Green Pricing Program.

New Rate Schedules

Q. Is MECO proposing any new rate schedules for Molokai Division?

A. Yes. MECO is proposing four new rate schedules for Molokai Division:

1. Schedule TOU-R – Residential Time-of-Use Service;
2. Schedule TOU-G – Small Commercial Time-of-Use Service;
3. Schedule TOU-J – Commercial Time-of-Use Service; and
4. Schedule TOU-P – Large Power Time-of-Use Service.

Optional Time-of-Use Service Rate Schedules

Q. Please describe the goals of offering four new time-of-use rate options in this case.

A. The Company proposes to offer four new time-of-use rate options in this case, Schedule TOU-R – Residential Time-of-Use Service, Schedule TOU-G – Small Commercial Time-of-Use Service, Schedule TOU-J – Commercial Time-of-Use Service, and Schedule TOU-P – Large Power Time-of-Use Service, in order to extend to all customers the opportunity to choose time-of-use rates, to establish a consistency in rate design for all time-of-use rate options, and to manage participation and collect data for future time-of-use rate designs. Making time-of-use rate options available to all customers, with the exception of street light customers, is consistent with the approach taken in the recent HECO rate

cases, Docket No. 04-0113 and Docket No. 2006-0386, as well as in HELCO's test year 2006 rate case, Docket No. 05-0315. It is consistent with the goals of the Energy Policy Act of 2005. The proposed time-of-use rate options have consistent time-of-use rating periods (priority peak, mid-peak, and off-peak periods) and consistent rate designs (demand charge based on priority peak and mid-peak, no demand ratchet, separate energy charges for each rating period). The time-of-use rate options are intended to create lower electric bills for customers who modify their existing energy consumption patterns. The Company proposes to manage participation in these optional rates while collecting data for future time-of-use rate design offerings by setting a limit on the number of meters that can participate in certain optional rate schedules. The meter limit facilitates effective implementation of these rate options since the current billing system cannot bill time-of-use rates automatically, and in case the new Customer Information System (CIS) is not yet in place by the time these proposed rates are approved. In addition, the Company has not estimated any revenue adjustment for customer participation in these time-of-use rate options, so the meter limit helps to mitigate any negative revenue impact that the Company might experience in implementing these rate options.

<u>Schedule TOU-R – Residential Time-of-Use Service</u>

Q. Please describe MECO's proposed Schedule TOU-R for Molokai Division.

A. Customers currently served under Schedule R are eligible to elect time-of-use service under Schedule TOU-R. The proposed Schedule TOU-R has the following parameters:

1. Customer Charge: $7.50 per month for Single-Phase Service, and

$12.00 per month for Three-Phase service;

2. Energy Charge: Calculated in the same manner and at the same rates as the proposed Schedule R, with the following time-of-use energy rate adjustments:

Priority Peak Period kWh use	+ 5.0 ¢ per kWh,
Mid-Peak Period kWh use	+ 2.5 ¢ per kWh, and
Off-Peak Period kWh use	- 5.0 ¢ per kWh;

3. Minimum Bill is the same as proposed for Schedule R;
4. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily; and

5. Service is limited to a maximum of 300 meters across all three MECO divisions.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $7.50 for Single-Phase Service and $12.00 for Three-Phase Service are the same as the proposed customer charges for Schedule R.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate adjustment for all kWh used in the priority peak period of + 5.0 ¢/kWh is based on 250% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of +2.5 ¢/kWh is based on

125% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period is based on about 170% of the existing off-peak energy credit for Rider T customers. However, even at the lowest energy tier, the effective off-peak kWh rate on Schedule TOU-R exceeds the off-peak marginal energy cost rate for 2007, and therefore makes a contribution towards fixed cost recovery.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-R are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Schedule TOU-G – Small Commercial Time-of-Use Service

Q. Please describe HELCO's proposed Schedule TOU-G for Molokai Division.

A. Customers currently served under Schedule G are eligible to elect time-of-use service under Schedule TOU-G. The proposed Schedule TOU-G has the following parameters:

1. Customer Charge: $23.00 per month for Single-Phase Service, and $34.00 per month for Three-Phase service;
2. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	46.7728 ¢ per kWh,
Mid-Peak Period kWh use	44.2728 ¢ per kWh, and
Off-Peak Period kWh use	36.7728 ¢ per kWh;

3. Minimum Bill is the same as the proposed Schedule TOU-G customer charge;
4. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily; and

5. Service is limited to a maximum of 100 meters across all three MECO divisions.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $23.00 for Single-Phase Service and $34.00 for Three-Phase Service are the same as the proposed customer charges for Schedule G.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 46.7728 ¢/kWh is based on the proposed Schedule G energy rate plus 250% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 44.2728 ¢/kWh is based on the proposed Schedule G energy rate plus 125% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 36.7728 ¢/kWh is based on the proposed Schedule G energy rate less about 170% of the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-G exceeds the off-peak marginal energy cost rate for 2007, and therefore makes a contribution towards fixed cost recovery.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-G are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Schedule TOU-J – Commercial Time-of-Use Service

Q. Please describe MECO's proposed Schedule TOU-J for Molokai Division.

A. Customers currently served under Schedule J are eligible to elect time-of-use service under Schedule TOU-J. The proposed Schedule TOU-J has the following parameters:

1. Customer Charge: $42.00 per month for Single-Phase Service, and $52.00 per month for Three-Phase service;
2. Demand Charge of $23.75 per kW if customer's maximum demand occurs during the priority peak period and $11.00 per kW if it occurs during the mid-peak period.
3. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	38.4868 ¢ per kWh,
Mid-Peak Period kWh use	36.4868 ¢ per kWh, and
Off-Peak Period kWh use	26.4868 ¢ per kWh;

4. Minimum Bill is the same as proposed for Schedule J, the sum of the Customer Charge and the Demand Charge; and
5. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily.

Q. How did you determine proposed customer charge for the single-phase service and three-phase service?

A. The proposed customer charge of $42.00 for Single-Phase Service and $52.00 for Three-Phase Service are based on the proposed customer charges for Schedule J, plus an additional $10.00 per month, which is the same as the current time-of-use meter charge in Rider T and Rider M.

Q. Please explain the proposed demand charge for Schedule TOU-J.

A. The proposed demand charge under Schedule TOU-J is based on the customer's maximum measured kW demand for the billing period. The Company is not proposing a demand ratchet in the determination of the billing demand – the same as in the current Schedule U. However, the minimum billing demand of 25 kW still applies. If the customer's maximum measured kW demand for the billing period occurs during the priority peak hours, the priority peak demand charge of $23.75 per kW is applied. If the customer's maximum measured kW demand for the billing period occurs during the mid-peak hours, the mid-peak demand charge of $11.00 per kW is applied. In other words, a customer is charged either the $23.75 per kW Priority Peak demand charge or the $11.00 per kW Mid-Peak demand charge based on when his maximum kW demand occurs. There is no demand charge for kW load during the off-peak hours. The determination of demand provision in the proposed Schedule TOU-J specifies the application of the proposed demand charge.

Q. How did you determine the proposed priority peak demand charge and the mid-peak demand charge?

A. The proposed demand charge of $23.75 per kW for the priority peak period is based on recovering approximately 50% of full unit demand cost for Schedule J at

proposed rates. The proposed demand charge of $11.00 per kW for mid-peak period is the same as the proposed demand charge for Schedule J.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 38.4868 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates plus 300% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 36.4868 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates plus 200% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 26.4868 ¢/kWh is based on the weighted average of the proposed Schedule J energy rates less about 200% of the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-J exceeds the off-peak marginal energy cost rate for 2007.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-J are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

<u>Schedule TOU-P – Large Power Time-of-Use Service</u>

Q. Please describe MECO's proposed Schedule TOU-P for Molokai Division.

A. Customers currently served under Schedule P are eligible to elect time-of-use service under Schedule TOU-P. The proposed Schedule TOU-P has the following parameters:

1. Customer Charge: $85.00 per month;

2. Demand Charge of $14.75 per kW if customer's maximum demand occurs during the priority peak period and $11.00 per kW if it occurs during the mid-peak period.
3. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	36.5525 ¢ per kWh,
Mid-Peak Period kWh use	34.5525 ¢ per kWh, and
Off-Peak Period kWh us	24.5525 ¢ per kWh;

4. Minimum Bill is the same as proposed for Schedule P, the sum of the Customer Charge and the Demand Charge; and
5. Time-of-Use rating periods are the following:

Priority Peak Period:	5:00 p.m. – 9:00 p.m., Monday – Friday
Mid-Peak Period:	7:00 a.m. – 5:00 p.m., Monday – Friday
	7:00 a.m. – 9:00 p.m., Saturday – Sunday
Off-Peak Period:	9:00 p.m. – 7 a.m., Daily.

Q. How did you determine proposed customer charge?

A. The proposed customer charge of $85.00 per month is based on the proposed customer charge for Schedule P, plus an additional $10.00 per month, which is the same as the current time-of-use meter charge in Rider T and Rider M.

Q. Please explain the proposed demand charge for Schedule TOU-P.

A. The proposed demand charge under Schedule TOU-P is based on the customer's maximum measured kW demand for the billing period. The Company is not proposing a demand ratchet in the determination of the billing demand – the same as in the current effective Schedule U. However, the minimum billing demand of 100 kW still applies. If the customer's maximum measured kW demand for the billing period occurs during the priority peak hours, the priority peak demand

charge of $14.75 per kW is applied. If the customer's maximum measured kW demand for the billing period occurs during the mid-peak hours, the mid-peak demand charge of $11.00 per kW is applied. In other words, a customer is charged either the $14.75 per kW Priority Peak demand charge or the $11.00 per kW Mid-Peak demand charge based on when his maximum kW demand occurs. There is no demand charge for kW load during the off-peak hours. The determination of demand provision in the proposed Schedule TOU-P specifies the application of the proposed demand charge.

Q. How did you determine the proposed priority peak demand charge and the mid-peak demand charge?

A. The proposed demand charge of $14.75 per kW for the priority peak period is based on recovering approximately 50% of full unit demand cost for Schedule P at proposed rates. The proposed demand charge of $11.00 per kW for mid-peak period is the same as the proposed demand charge for the first kW tier on Schedule P.

Q. How were the proposed time-of-use energy rate adjustments determined?

A. The proposed time-of-use energy rate for all kWh used in the priority peak period of 36.5525 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates plus 300% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the mid-peak period of 34.5525 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates plus 200% of the existing on-peak energy surcharge for Rider T customers. The proposed time-of-use energy rate adjustment for all kWh used in the off-peak period of 24.5525 ¢/kWh is based on the weighted average of the proposed Schedule P energy rates less about 200% of

the existing off-peak energy credit for Rider T customers. The off-peak kWh rate on Schedule TOU-P exceeds the off-peak marginal energy cost rate for 2007.

Q. Are these time-of-use rating periods the same as currently used in MECO's existing time-of-use Riders or Schedules?

A. Yes, the time-of-use rating periods proposed for Schedule TOU-P are the same as used in MECO's existing Rider M, Rider T, and Schedule U.

Standby Charge

Q. Are there any other proposed new rates?

A. Pursuant to Decision and Order No. 22248 in Docket No. 03-0371 on Distributed Generation, the Company proposed Standby Rates for Maui, Lanai, and Molokai Divisions. The proposed Standby Rates will be reviewed in a separate proceeding, Docket No. 2006-0497, pursuant to the Commission's Order No. 23171.

Electric Vehicle Charging Rates

Q. Is MECO proposing to terminate any existing rate schedule or rate adjustment for Molokai Division?

A. Yes. MECO is proposing to withdraw the Rider EV-R – Residential Electric Vehicle Charging Service, Rider EV-C – Commercial Electric Vehicle Charging Service. MECO is also terminating the Firm Capacity Surcharge refund for the termination of capacity payments to Pioneer Mill. This reduction in capacity payments is reflected in the test-year estimates of the purchased power expense and embedded in the new proposed rate changes.

Q. Why is MECO proposing to withdraw Riders EV-R and EV-C?

A. HECO's Rider EV-R and Rider EV-C became effective on July 6, 1998. On August 13, 1998, HECO agreed to defer implementation of the riders per Commission's request in an August 3, 1998 letter. HECO has not received PUC approval to implement these riders, although they remained in MECO's current effective rates.

More importantly, MECO's proposed Schedule TOU-R, Schedule TOU-G, Schedule TOU-J, and Schedule TOU-P will also apply to electric vehicle charging service. These proposed new Schedules will provide time-of-use service to electric vehicle charging without the need to separately meter these loads from the rest of the customers' electric loads, as required under the Rider EV-R and Rider EV-C, which were available only for the electric vehicle charging load.

SERVICE-RELATED CHARGES AND PROPOSED RULE CHANGES

Q. What are service-related charges?

A. In addition to the rate schedules and riders, there are service-related charges included in the Company's Rules that are charged directly to the customers who caused the costs to be incurred by the utility. These service-related direct charges include the Service Establishment and Reconnection Charge in the Company's Rule No. 7, Section C, and the Returned Check Charge, Field Collection Charge, and Late Payment Charge in Rule No. 8, Sections D, E, and F, respectively.

Q. Are there any changes to these charges?

A. Yes. The Company is proposing the following changes:

1) increase the Service Establishment Charge from $15.00 to $25.00, and increase the additional charge for the same day service or for service outside of the normal business hours from the current $10.00 to $20.00;

2) change the Returned Check Charge to a Returned Payment Charge and increase the charge from the current $10.00 to $25.00 per returned check or returned payment; and

3) increase the Field Collection Charge from $15.00 to $25.00 per field collection call.

Q. Why is the Company proposing to change the "Returned Checks Charge" to "Returned Payment Charge"?

A. The Company is proposing to change the "Returned Checks Charge" to "Returned Payment Charge" to reflect the different payment options that are now available to customers, and to allow the Company to apply the same service charge on "returned" payments made through any of these options.

Q. What payment options are now available to the customers?

A. In the past, customers could pay their electric bill either by check or in cash. With the changes in technology, MECO started offering customers with different electronic bill payment options of paying their electric bills ("e-billing"). The various e-billing options that are available to MECO customers include the following:

1. Automatic Bill Payment (ABP) – automatically debits customer's savings or checking account;
2. Payment using credit card, and
3. Payment using debit card

When payments made through any of these "paperless" payment options are "returned" due to insufficient funds in the customers' accounts, the bank charges MECO a service charge for the processing cost – similar to a bounced check processing fee. For fairness and equity, MECO is proposing to change

the Returned Checks Charge to Returned Payment Charge and to apply it to any "returned" payment from any of the "paperless" payments in addition to returned checks. The proposed change will charge the cost of such returned payments to those customers who cause such costs to be incurred by MECO, rather than shifting those costs to the other ratepayers.

Q. How did you determine the proposed Returned Payment Charge of $25.00 per returned payment?

A. See the calculations presented in MECO-712 and MECO-WP-712 in Ms. Sharon Suzuki's MECO T-7 testimony.

Q. Please explain how the proposed changes to the Field Collection Charge and Service Establishment Charge were determined.

A. The proposed Field Collection Charge and Service Establishment Charge, including the same day service connection charge are based on the costs of various activities required for these services. See the calculations presented in MECO-712 and MECO-WP-712 in Ms. Sharon Suzuki's MECO T-7 testimony.

Rule No. 14 Interconnection

Q. Are there any other proposed new rules?

A. Pursuant to Decision and Order No. 22248 in Docket No. 03-0371 on Distributed Generation, the Company proposed modifications to Rule No. 14 for MECO. The proposed rule changes will be reviewed in a separate proceeding, Docket No. 2006-0497, pursuant to the Commission's Order No. 23171.

SUMMARY

Q. Please summarize your testimony.

A. My testimony presented the Company's embedded cost-of-service studies for each MECO division, the basis and determination of the proposed rates, and the proposed changes to the Company's tariffs. The Company proposes to implement an inclining rate block structure for Schedule R, modify the demand billing calculation for Schedule J, close Schedule H and Schedule U to new customers, and close Schedule N at Molokai Division to new accounts. In addition to the proposed changes to the current rate schedules, the Company is also proposing 4 new rate schedules – Schedules TOU-R, TOU-G, TOU-J, and TOU-P – for Commission approval, as well as changes to the service-related charges including the Returned Check Charge, Field Collection Charge, and Service Establishment Charge.

Q. Does this complete your testimony?

A. Yes.

MAUI ELECTRIC COMPANY, LIMITED
TEST YEAR 2007 DOCKET NO. 2006-0387

SUMMARY OF "FULL COST" TOTAL
REVENUE REQUIREMENTS BY DIVISION

	Maui	Lanai	Molokai	Consolidated
	($000s)	($000s)	($000s)	($000s)
Present Rates[1]				
Sales Revenues	333,075.2	10,066.7	12,631.4	355,773.3
Other Oper. Revenues	1,389.0	37.9	107.1	1,534.0
Total Oper. Revenues	334,464.2	10,104.6	12,738.5	357,307.3
Percent of Total	93.6%	2.8%	3.6%	100.0%
"Full Cost" Revenue Requirements				
Sales Revenues	348,654.0	12,015.0	13,858.0	374,527.0
Other Oper. Revenues	1,590.0	47.0	122.0	1,759.0
Total Oper. Revenues	350,244.0	12,062.0	13,980.0	376,286.0
Percent of Total	93.1%	3.2%	3.7%	100.0%
"Full Cost" Increase				
Sales Revenues	15,578.8	1,948.3	1,226.6	18,753.7
Other Oper. Revenues	201.0	9.1	14.9	225.0
Total Oper. Revenues	15,779.8	1,957.4	1,241.5	18,978.7
Percent of Total	83.1%	10.3%	6.5%	100.0%
Percent Increase				
Sales Revenues	4.7%	19.4%	9.7%	5.3%
Other Oper. Revenues	14.5%	24.0%	13.9%	14.7%
Total Oper. Revenues	4.7%	19.4%	9.7%	5.3%

[1]MECO rates effective April 15, 1999

MAUI ELECTRIC COMPANY, LIMITED
TEST YEAR 2007 DOCKET NO. 2006-0387

SUMMARY OF PROPOSED TOTAL
REVENUE REQUIREMENTS BY DIVISION

	Maui	Lanai	Molokai	Consolidated
	($000s)	($000s)	($000s)	($000s)
Present Rates[1]				
Sales Revenues	333,075.2	10,066.7	12,631.4	355,773.3
Other Oper. Revenues	1,389.0	37.9	107.1	1,534.0
Total Oper. Revenues	334,464.2	10,104.6	12,738.5	357,307.3
Percent of Total	93.6%	2.8%	3.6%	100.0%
Proposed Revenue Requirements				
Sales Revenues	350,632.5	10,597.3	13,297.3	374,527.1
Other Oper. Revenues	1,589.0	46.9	122.1	1,758.0
Total Oper. Revenues	352,221.5	10,644.2	13,419.4	376,285.1
Percent of Total	93.6%	2.8%	3.6%	100.0%
Proposed Increase				
Sales Revenues	17,557.3	530.6	665.9	18,753.8
Other Oper. Revenues	200.0	9.0	15.0	224.0
Total Oper. Revenues	17,757.3	539.6	680.9	18,977.8
Percent of Total	93.6%	2.8%	3.6%	100.0%
Percent Increase				
Sales Revenues	5.3%	5.3%	5.3%	5.3%
Other Oper. Revenues	14.4%	23.7%	14.0%	14.6%
Total Oper. Revenues	5.3%	5.3%	5.3%	5.3%

[1]MECO rates effective April 15, 1999

MAUI ELECTRIC COMPANY, INC. - *Maui Division*
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
AT PRESENT RATES AND AT PROPOSED RATES

	Present Rates			Proposed Rates			Proposed Increase	
Rate Class	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Amount ($000s)	Percent (%)
Schedule R	$121,916.2	3.36%	51.48%	$128,342.8	5.56%	59.84%	$6,426.6	5.27%
Schedule G	$29,812.9	8.49%	130.15%	$31,384.4	11.05%	118.93%	$1,571.5	5.27%
Schedule J	$75,029.6	11.80%	180.81%	$78,984.6	15.26%	164.32%	$3,955.0	5.27%
Schedule H	$5,909.6	4.96%	75.97%	$6,221.1	7.84%	84.42%	$311.5	5.27%
Schedule P	$98,985.7	8.50%	130.25%	$104,203.5	12.08%	130.04%	$5,217.8	5.27%
Schedule F	$1,421.2	1.76%	26.97%	$1,496.1	2.58%	27.78%	$74.9	5.27%
Total Sales Revenues	$333,075.2			$350,632.5			$17,557.3	5.27%
Other Operating Revenues	$1,389.0			$1,589.0			$200.0	14.40%
Total Revenues	$334,464.2	6.52%	100.00%	$352,221.5	9.29%	100.00%	$17,757.3	5.31%

MAUI ELECTRIC COMPANY, INC. - Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
AT PRESENT RATES AND AT PROPOSED RATES

Rate Class	Present Rates			Proposed Rates			Proposed Increase	
	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Amount ($000s)	Percent (%)
Schedule R	$2,731.6	-6.84%	-911.82%	$2,875.6	-5.22%	-173.36%	$144.0	5.27%
Schedule G	$725.2	3.47%	462.50%	$763.4	5.74%	190.70%	$38.2	5.27%
Schedule J	$2,253.8	6.32%	842.93%	$2,372.6	8.81%	292.61%	$118.8	5.27%
Schedule H	$180.5	5.82%	776.02%	$190.0	8.69%	288.50%	$9.5	5.26%
Schedule P	$4,138.7	6.15%	820.23%	$4,356.9	9.08%	301.47%	$218.2	5.27%
Schedule F	$36.9	-3.65%	-486.52%	$38.8	-2.55%	-84.69%	$1.9	5.15%
Total Sales Revenues	$10,066.7			$10,597.3			$530.6	5.27%
Other Operating Revenues	$37.9			$46.9			$9.0	23.75%
Total Revenues	$10,104.6	0.75%	100.00%	$10,644.2	3.01%	100.00%	$539.6	5.34%

MAUI ELECTRIC COMPANY, INC. - Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
AT PRESENT RATES AND AT PROPOSED RATES

Rate Class	Present Rates			Proposed Rates			Proposed Increase	
	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Sales Revenues ($000s)	Rate of Return (%)	ROR Index (%)	Amount ($000s)	Percent (%)
Schedule R	$4,556.7	-2.13%	-49.57%	$4,796.9	0.24%	3.51%	$240.2	5.27%
Schedule G	$1,703.7	17.79%	413.95%	$1,793.5	20.50%	298.87%	$89.8	5.27%
Schedule J	$2,831.8	15.65%	364.04%	$2,981.1	18.67%	272.17%	$149.3	5.27%
Schedule H	$643.4	0.04%	1.03%	$677.3	2.44%	35.62%	$33.9	5.27%
Schedule P	$2,734.9	-1.39%	-32.24%	$2,879.1	1.12%	16.35%	$144.2	5.27%
Schedule F	$160.9	20.73%	482.39%	$169.4	22.80%	332.43%	$8.5	5.28%
Total Sales Revenues	$12,631.4			$13,297.3			$665.9	5.27%
Other Operating Revenues	$107.1			$122.1			$15.0	14.01%
Total Revenues	$12,738.5	4.30%	100.00%	$13,419.4	6.86%	100.00%	$680.9	5.35%

MAUI ELECTRIC COMPANY, INC. Maui Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate Base ($000s)	Return on Rate Base (%)
Schedule R	$122,342.7	$116,714.1	$5,628.6	$167,584.8	3.36%
Schedule G	$29,872.1	$26,937.1	$2,935.0	$34,563.3	8.49%
Schedule J	$75,111.6	$67,597.5	$7,514.1	$63,696.8	11.80%
Schedule H	$5,917.0	$5,618.4	$298.6	$6,024.2	4.96%
Schedule P	$99,017.1	$92,110.3	$6,906.8	$81,275.7	8.50%
Schedule F	$2,203.7	$2,114.2	$89.5	$5,084.4	1.76%
TOTAL	$334,464.2	$311,091.6	$23,372.6	$358,229.1	6.52%

MAUI ELECTRIC COMPANY, INC. Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate Base ($000s)	Return on Rate Base (%)
Schedule R	$2,745.4	$3,106.3	($360.9)	$5,276.5	-6.84%
Schedule G	$726.2	$693.6	$32.6	$938.6	3.47%
Schedule J	$2,255.6	$2,088.7	$166.9	$2,640.1	6.32%
Schedule H	$180.8	$170.1	$10.7	$183.4	5.82%
Schedule P	$4,140.7	$3,887.0	$253.7	$4,123.4	6.15%
Schedule F	$55.9	$59.4	($3.5)	$96.4	-3.65%
TOTAL	$10,104.6	$10,005.1	$99.5	$13,258.4	0.75%

MAUI ELECTRIC COMPANY, INC. Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

Rate Class	Total Operating *Revenues* ($000s)	Total Operating *Expenses* ($000s)	Total Operating *Income* ($000s)	*Rate Base* ($000s)	Return on *Rate Base* (%)
Schedule R	$4,582.2	$4,709.2	($127.0)	$5,961.8	-2.13%
Schedule G	$1,707.5	$1,376.4	$331.1	$1,861.2	17.79%
Schedule J	$2,834.6	$2,406.8	$427.8	$2,734.2	15.65%
Schedule H	$644.4	$644.1	$0.3	$787.9	0.04%
Schedule P	$2,737.9	$2,782.3	($44.4)	$3,202.0	-1.39%
Schedule F	$231.9	$184.8	$47.1	$227.1	20.73%
TOTAL	$12,738.5	$12,103.5	$635.0	$14,774.3	4.30%

MAUI ELECTRIC COMPANY, INC. - Maui Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PROPOSED RATES

Rate Class	*Total Operating* Revenues ($000s)	*Total Operating* Expenses ($000s)	*Total Operating* Income ($000s)	Rate base ($000s)	*Return on* Rate Base (%)
Schedule R	$128,955.6	$119,643.3	$9,312.3	$167,516.6	5.56%
Schedule G	$31,455.6	$27,639.0	$3,816.6	$34,547.0	11.05%
Schedule J	$79,068.0	$69,351.7	$9,716.4	$63,656.1	15.26%
Schedule H	$6,228.8	$5,756.7	$472.1	$6,021.0	7.84%
Schedule P	$104,234.9	$94,423.7	$9,811.1	$81,221.9	12.08%
Schedule F	$2,278.6	$2,147.5	$131.2	$5,083.6	2.58%
TOTAL	$352,221.5	$318,961.9	$33,259.6	$358,046.1	9.29%

MAUI ELECTRIC COMPANY, INC. - Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PROPOSED RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate base ($000s)	Return on Rate Base (%)
Schedule R	$2,898.1	$3,173.9	($275.8)	$5,282.7	-5.22%
Schedule G	$764.7	$710.7	$54.0	$940.2	5.74%
Schedule J	$2,374.4	$2,141.3	$233.1	$2,644.9	8.81%
Schedule H	$190.3	$174.3	$16.0	$183.8	8.69%
Schedule P	$4,358.9	$3,983.7	$375.2	$4,132.3	9.08%
Schedule F	$57.8	$60.3	($2.5)	$96.5	-2.55%
TOTAL	$10,644.2	$10,244.3	$399.9	$13,280.4	3.01%

MAUI ELECTRIC COMPANY, INC. - Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PROPOSED RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate base ($000s)	Return on Rate Base (%)
Schedule R	$4,835.8	$4,821.5	$14.3	$5,967.4	0.24%
Schedule G	$1,798.6	$1,416.7	$381.9	$1,863.2	20.50%
Schedule J	$2,984.0	$2,473.0	$511.0	$2,737.5	18.67%
Schedule H	$678.4	$659.1	$19.3	$788.6	2.44%
Schedule P	$2,882.2	$2,846.2	$35.9	$3,205.1	1.12%
Schedule F	$240.4	$188.6	$51.8	$227.3	22.80%
TOTAL	$13,419.4	$12,405.2	$1,014.2	$14,789.3	6.86%

MAUI ELECTRIC COMPANY, INC. - Maui Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

ALLOCATION OF RATE INCREASE BASED ON EQUAL CLASS ROR FROM PRESENT RATES

Rate Class	Sales Revenues at Present Rates	Rev Requirements at Equal ROR	REVENUE INCREASE			CLASS RATES OF RETURN	
	($000s)	($000s)	($000s)	% Increase	% of Total	At Present Rates (%)	At Equal ROR (%)
Schedule R	$121,916.2	$138,656.8	$16,740.6	13.73%	107.3%	3.36%	8.99%
Schedule G	$29,812.9	$30,103.0	$290.1	0.97%	1.9%	8.49%	8.98%
Schedule J	$75,029.6	$71,804.6	($3,225.0)	-4.30%	-20.7%	11.80%	8.97%
Schedule H	$5,909.6	$6,344.6	$435.0	7.36%	2.8%	4.96%	8.99%
Schedule P	$98,985.7	$99,686.5	$700.8	0.71%	4.5%	8.50%	8.98%
Schedule F	$1,421.2	$2,081.1	$659.9	46.43%	4.2%	1.76%	9.00%
Total Sales Revenues	$333,075.2	$348,676.5	$15,601.3	4.68%	100.0%		
Other Operating Revenues	$1,389.0	$1,589.0	$200.0	14.40%			
TOTAL SYSTEM	$334,464.2	$350,265.5	$15,801.3	4.72%		6.52%	8.99%

MAUI ELECTRIC COMPANY, INC. - Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

ALLOCATION OF RATE INCREASE BASED ON EQUAL CLASS ROR FROM PRESENT RATES

Rate Class	Sales Revenues at Present Rates	Rev Requirements at Equal ROR	REVENUE INCREASE			CLASS RATES OF RETURN	
	($000s)	($000s)	($000s)	% Increase	% of Total	At Present Rates (%)	At Equal ROR (%)
Schedule R	$2,731.6	$4,225.6	$1,494.0	54.69%	76.4%	-6.84%	8.99%
Schedule G	$725.2	$818.1	$92.9	12.81%	4.8%	3.47%	8.99%
Schedule J	$2,253.8	$2,380.0	$126.2	5.60%	6.5%	6.32%	8.98%
Schedule H	$180.5	$191.0	$10.5	5.81%	0.5%	5.82%	9.03%
Schedule P	$4,138.7	$4,348.6	$209.9	5.07%	10.7%	6.15%	8.98%
Schedule F	$36.9	$58.8	$21.9	59.35%	1.1%	-3.65%	8.99%
Total Sales Revenues	$10,066.7	$12,022.1	$1,955.4	19.42%	100.0%		
Other Operating Revenues	$37.9	$46.9	$9.0	23.75%			
TOTAL SYSTEM	$10,104.6	$12,069.0	$1,964.4	19.44%		0.75%	8.99%

MAUI ELECTRIC COMPANY, INC. - Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

ALLOCATION OF RATE INCREASE BASED ON EQUAL CLASS ROR FROM PRESENT RATES

Rate Class	Sales Revenues at Present Rates	Rev Requirements at Equal ROR	REVENUE INCREASE			CLASS RATES OF RETURN	
	($000s)	($000s)	($000s)	% increase	% of Total	At Present Rates (%)	At Equal ROR (%)
Schedule R	$4,556.7	$5,736.6	$1,179.9	25.89%	95.8%	-2.13%	8.99%
Schedule G	$1,703.7	$1,407.0	($296.7)	-17.42%	-24.1%	17.79%	8.98%
Schedule J	$2,831.8	$2,503.5	($328.3)	-11.59%	-26.7%	15.65%	8.98%
Schedule H	$643.4	$770.1	$126.7	19.69%	10.3%	0.04%	8.99%
Schedule P	$2,734.9	$3,332.7	$597.8	21.86%	48.5%	-1.39%	8.99%
Schedule F	$160.9	$113.0	($47.9)	-29.77%	-3.9%	20.73%	9.05%
Total Sales Revenues	$12,631.4	$13,862.9	$1,231.5	9.75%	100.0%		
Other Operating Revenues	$107.1	$122.1	$15.0	14.01%			
TOTAL SYSTEM	$12,738.5	$13,985.0	$1,246.5	9.79%		4.30%	8.99%

MAUI ELECTRIC COMPANY, INC. - Maui Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

COMPARISON OF CLASS REVENUE REQUIREMENTS AT PRESENT RATES, AT PROPOSED RATES AND AT EQUAL RATES OF RETURN

				CLASS RATES OF RETURN		
Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	Sales Revenues at Equal ROR ($000s)	At Present Rates (%)	At Proposed Rates (%)	At Equal ROR (%)
Schedule R	$121,916.2	$128,342.8	$138,656.8	3.36%	5.56%	8.99%
Schedule G	$29,812.9	$31,384.4	$30,103.0	8.49%	11.05%	8.98%
Schedule J	$75,029.6	$78,984.6	$71,804.6	11.80%	15.26%	8.97%
Schedule H	$5,909.6	$6,221.1	$6,344.6	4.96%	7.84%	8.99%
Schedule P	$98,985.7	$104,203.5	$99,686.5	8.50%	12.08%	8.98%
Schedule F	$1,421.2	$1,496.1	$2,081.1	1.76%	2.58%	9.00%
Total Sales Revenues	$333,075.2	$350,632.5 [1]	$348,676.5 [1]			
Other Operating Revenues	$1,389.0	$1,589.0	$1,589.0			
TOTAL SYSTEM	$334,464.2	$352,221.5 [1]	$350,265.5 [1]	6.52%	9.29%	8.99%

[1] The totals may not exactly equal due to rounding.

MAUI ELECTRIC COMPANY, INC. - Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

COMPARISON OF CLASS REVENUE REQUIREMENTS AT PRESENT RATES, AT PROPOSED RATES AND AT EQUAL RATES OF RETURN

				CLASS RATES OF RETURN		
Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	Sales Revenues at Equal ROR ($000s)	At Present Rates (%)	At Proposed Rates (%)	At Equal ROR (%)
Schedule R	$2,731.6	$2,875.6	$4,225.6	-6.84%	-5.22%	8.99%
Schedule G	$725.2	$763.4	$818.1	3.47%	5.74%	8.99%
Schedule J	$2,253.8	$2,372.6	$2,380.0	6.32%	8.81%	8.98%
Schedule H	$180.5	$190.0	$191.0	5.82%	8.69%	9.03%
Schedule P	$4,138.7	$4,356.9	$4,348.6	6.15%	9.08%	8.98%
Schedule F	$36.9	$38.8	$58.8	-3.65%	-2.55%	8.99%
Total Sales Revenues	$10,066.7	$10,597.3 [1]	$12,022.1 [1]			
Other Operating Revenues	$37.9	$46.9	$46.9			
TOTAL SYSTEM	$10,104.6	$10,644.2 [1]	$12,069.0 [1]	0.75%	3.01%	8.99%

[1] The totals may not exactly equal due to rounding.

MAUI ELECTRIC COMPANY, INC. - Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

COMPARISON OF CLASS REVENUE REQUIREMENTS AT PRESENT RATES, AT PROPOSED RATES
AND AT EQUAL RATES OF RETURN

				CLASS RATES OF RETURN		
Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	Sales Revenues at Equal ROR ($000s)	At Present Rates (%)	At Proposed Rates (%)	At Equal ROR (%)
Schedule R	$4,556.7	$4,796.9	$5,736.6	-2.13%	0.24%	8.99%
Schedule G	$1,703.7	$1,793.5	$1,407.0	17.79%	20.50%	8.98%
Schedule J	$2,831.8	$2,981.1	$2,503.5	15.65%	18.67%	8.98%
Schedule H	$643.4	$677.3	$770.1	0.04%	2.44%	8.99%
Schedule P	$2,734.9	$2,879.1	$3,332.7	-1.39%	1.12%	8.99%
Schedule F	$160.9	$169.4	$113.0	20.73%	22.80%	9.05%
Total Sales Revenues	$12,631.4	$13,297.3 [1]	$13,862.9 [1]			
Other Operating Revenues	$107.1	$122.1	$122.1			
TOTAL SYSTEM	$12,738.5	$13,419.4 [1]	$13,985.0 [1]	4.30%	6.86%	8.99%

[1] The totals may not exactly equal due to rounding.

MAUI ELECTRIC COMPANY, INC. - Maui division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

Rate Class	COST COMPONENTS AT PROPOSED RATES							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$33,406.0	32.44%	$79,113.0	35.31%	$15,823.8	67.05%	$128,342.8	36.60%
Schedule G	$9,709.8	9.43%	$17,659.1	7.97%	$3,815.5	16.17%	$31,384.4	8.95%
Schedule J	$26,962.9	26.18%	$50,141.1	22.38%	$1,880.6	7.97%	$78,984.6	22.53%
Schedule H	$1,764.1	1.71%	$3,891.9	1.74%	$565.1	2.39%	$6,221.1	1.77%
Schedule PS	$30,988.0	30.09%	$72,091.3	32.18%	$1,124.2	4.76%	$104,203.5	29.72%
Schedule F	$143.3	0.14%	$962.8	0.43%	$390.0	1.65%	$1,496.1	0.43%
TOTAL	$102,974.1	100.00%	$224,059.2	100.00%	$23,599.2	100.00%	$350,632.5	100.00%
PERCENT OF TOTAL	29.37%		63.90%		6.73%		100.00%	

MAUI ELECTRIC COMPANY, INC. - Lanai division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

Rate Class	COST COMPONENTS AT PROPOSED RATES							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$689.9	20.84%	$1,856.2	27.20%	$329.5	71.32%	$2,875.6	27.14%
Schedule G	$229.4	6.93%	$450.6	6.60%	$83.4	18.04%	$763.4	7.20%
Schedule J	$899.3	27.17%	$1,444.0	21.16%	$29.4	6.35%	$2,372.6	22.39%
Schedule H	$60.7	1.83%	$126.6	1.86%	$2.7	0.58%	$190.0	1.79%
Schedule PS	$1,429.5	43.19%	$2,922.8	42.82%	$4.6	0.99%	$4,356.9	41.11%
Schedule F	$1.0	0.03%	$25.3	0.37%	$12.5	2.71%	$38.8	0.37%
TOTAL	$3,309.8	100.00%	$6,825.5	100.00%	$462.0	100.00%	$10,597.3	100.00%
PERCENT OF TOTAL	31.23%		64.41%		4.36%		100.00%	

MAUI ELECTRIC COMPANY, INC. - Molokai division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

Rate Class	COST COMPONENTS AT PROPOSED RATES							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$1,410.5	31.51%	$2,865.1	35.61%	$521.3	67.23%	$4,796.9	36.08%
Schedule G	$751.5	16.79%	$883.4	10.98%	$158.6	20.46%	$1,793.5	13.49%
Schedule J	$1,150.0	25.69%	$1,790.9	22.26%	$40.2	5.19%	$2,981.1	22.42%
Schedule H	$228.2	5.10%	$438.1	5.44%	$11.0	1.42%	$677.3	5.09%
Schedule PS	$902.4	20.16%	$1,964.7	24.42%	$12.0	1.55%	$2,879.1	21.65%
Schedule F	$33.7	0.75%	$103.4	1.29%	$32.2	4.16%	$169.4	1.27%
TOTAL	$4,476.2	100.00%	$8,045.6	100.00%	$775.4	100.00%	$13,297.3	100.00%
PERCENT OF TOTAL	33.65%		60.51%		5.83%		99.99%	

MAUI ELECTRIC COMPANY, INC. - Maui Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

	Unit Cost Components At Proposed Rates			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$10.77	18.391	$25.66	29.836
Schedule G	$22.97	18.566	$43.10	32.627
Schedule J	$32.04	18.696	$112.34	29.451
Schedule H	$26.21	18.467	$202.11	29.519
Schedule P	$38.90	18.392	$774.27	26.585
Schedule F	$9.14	18.030	$192.30	28.017
TOTAL	$19.63	18.473	$32.40	28.908

MAUI ELECTRIC COMPANY, INC. - Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

	Unit Cost Components At Proposed Rates			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$10.83	22.685	$20.01	35.142
Schedule G	$31.61	23.115	$36.95	39.161
Schedule J	$20.34	23.235	$67.95	38.178
Schedule H	$61.48	23.233	$55.81	34.862
Schedule P	$61.41	22.881	$126.90	34.108
Schedule F	$2.92	22.212	$348.10	34.125
TOTAL	$23.67	22.920	$23.97	35.586

MAUI ELECTRIC COMPANY, INC. - Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

	Unit Cost Components At Proposed Rates			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$15.20	21.909	$17.06	36.682
Schedule G	$34.97	22.343	$28.68	45.360
Schedule J	$47.52	22.316	$42.45	37.147
Schedule H	$36.43	21.968	$28.62	33.963
Schedule P	$29.49	21.783	$71.43	31.921
Schedule F	$23.67	21.617	$298.50	35.402
TOTAL	$25.33	22.014	$20.57	36.383

MAUI ELECTRIC COMPANY, INC. - Maui Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF COST COMPONENTS BY RATE CLASS AT EQUAL RATES OF RETURN

Rate Class	COST COMPONENTS AT EQUAL RATES OF RETURN							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$40,319.9	40.81%	$79,571.6	35.59%	$18,764.9	71.32%	$138,656.4	39.77%
Schedule G	$8,808.1	8.92%	$17,797.5	7.96%	$3,498.2	13.30%	$30,103.8	8.63%
Schedule J	$20,575.2	20.83%	$49,617.4	22.19%	$1,611.8	6.13%	$71,804.4	20.59%
Schedule H	$1,869.7	1.89%	$3,899.3	1.74%	$575.5	2.19%	$6,344.5	1.82%
Schedule PS	$26,891.7	27.22%	$71,718.0	32.08%	$1,076.9	4.09%	$99,686.6	28.59%
Schedule F	$325.3	0.33%	$973.5	0.44%	$782.3	2.97%	$2,081.1	0.60%
TOTAL	$98,790.0	100.00%	$223,577.3	100.00%	$26,309.5	100.00%	$348,676.8	100.00%
PERCENT OF TOTAL	28.33%		64.12%		7.55%		100.00%	

MAUI ELECTRIC COMPANY, INC. - Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF COST COMPONENTS BY RATE CLASS AT EQUAL RATES OF RETURN

Rate Class	*COST COMPONENTS AT EQUAL RATES OF RETURN*							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$1,668.7	38.42%	$1,915.9	27.81%	$641.2	81.12%	$4,225.7	35.15%
Schedule G	$269.9	6.21%	$453.8	6.59%	$94.6	11.97%	$818.3	6.81%
Schedule J	$906.0	20.86%	$1,444.5	20.97%	$29.6	3.75%	$2,380.2	19.80%
Schedule H	$61.6	1.42%	$126.7	1.84%	$2.6	0.33%	$190.9	1.59%
Schedule PS	$1,421.7	32.74%	$2,922.1	42.42%	$4.5	0.57%	$4,348.3	36.17%
Schedule F	$14.8	0.34%	$26.0	0.38%	$17.9	2.27%	$58.7	0.49%
TOTAL	$4,342.7	100.00%	$6,889.0	100.00%	$790.4	100.00%	$12,022.1	100.00%
PERCENT OF TOTAL	36.12%		57.30%		6.57%		100.00%	

MAUI ELECTRIC COMPANY, INC. - Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF COST COMPONENTS BY RATE CLASS AT EQUAL RATES OF RETURN

Rate Class	COST COMPONENTS AT EQUAL RATES OF RETURN							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$2,171.6	44.07%	$2,914.2	36.09%	$651.0	75.60%	$5,736.9	41.38%
Schedule G	$421.9	8.56%	$863.9	10.70%	$121.3	14.08%	$1,407.0	10.15%
Schedule J	$713.1	14.47%	$1,757.5	21.77%	$32.9	3.82%	$2,503.5	18.06%
Schedule H	$313.6	6.36%	$443.7	5.50%	$12.8	1.49%	$770.2	5.56%
Schedule PS	$1,323.3	26.86%	$1,994.9	24.71%	$14.4	1.67%	$3,332.6	24.04%
Schedule F	($16.1)	-0.33%	$100.6	1.25%	$28.7	3.33%	$113.2	0.82%
TOTAL	$4,927.4	100.00%	$8,074.9	100.00%	$861.1	100.00%	$13,863.4	100.00%
PERCENT OF TOTAL	35.54%		58.25%		6.21%		100.00%	

MAUI ELECTRIC COMPANY, INC. - Maui Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT EQUAL RATES OF RETURN

	Unit Cost Components At Equal Rates of Return			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$13.00	18.498	$30.42	32.233
Schedule G	$20.84	18.502	$39.51	31.295
Schedule J	$24.44	18.501	$96.27	26.773
Schedule H	$27.78	18.502	$205.84	30.104
Schedule P	$33.75	18.297	$741.68	25.433
Schedule F	$20.73	18.231	$385.71	38.972
TOTAL	$18.83	18.433	$36.11	28.747

MAUI ELECTRIC COMPANY, INC. - Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT EQUAL RATES OF RETURN

	Unit Cost Components At Equal Rates of Return			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$26.20	23.414	$38.94	51.642
Schedule G	$37.18	23.281	$41.91	41.977
Schedule J	$20.49	23.244	$68.59	38.300
Schedule H	$62.38	23.251	$54.32	35.028
Schedule P	$61.08	22.876	$124.85	34.041
Schedule F	$42.58	22.859	$497.62	51.627
TOTAL	$31.07	23.134	$41.01	40.371

MAUI ELECTRIC COMPANY, INC. - Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT EQUAL RATES OF RETURN

	Unit Cost Components At Equal Rates of Return			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$23.42	22.285	$21.31	43.870
Schedule G	$19.63	21.848	$21.92	35.585
Schedule J	$29.46	21.901	$34.68	31.196
Schedule H	$50.04	22.251	$33.45	38.622
Schedule P	$43.24	22.118	$85.76	36.949
Schedule F	($11.28)	21.026	$265.48	23.657
TOTAL	$27.87	22.094	$22.85	37.932

MAUI ELECTRIC COMPANY, INC. - Maui Division
DOCKET NO. 2006-0387, TEST-YEAR 2007
SUMMARY OF ALLOCATION FACTORS

ALLOCATION BASIS		Schedule R	Schedule G	Schedule J	Schedule H	Schedule P	Schedule F	Total
Demand Allocation Factors:								
Average-Excess Demand	D1	39.73%	8.78%	20.85%	1.88%	28.19%	0.57%	100.00%
Class Peak Demand	D2	42.95%	9.41%	19.88%	1.98%	25.10%	0.67%	100.00%
Composite NCD	D3	56.31%	9.69%	19.67%	1.82%	11.96%	0.54%	100.00%
Energy Allocation Factors:								
Gross Input	E1	35.60%	7.96%	22.19%	1.74%	32.07%	0.44%	100.00%
Customer Allocation Factors:								
Primary Lines	C1	79.08%	15.55%	4.08%	0.66%	0.37%	0.26%	100.00%
Secondary Lines	C2	82.76%	13.31%	2.92%	0.48%	0.26%	0.27%	100.00%
Transformers	C3	74.79%	17.50%	5.44%	0.75%	1.27%	0.25%	100.00%
Services	C4	81.98%	13.18%	2.96%	0.48%	1.14%	0.27%	100.00%
Meter	C5	81.49%	13.92%	2.94%	0.48%	0.90%	0.27%	100.00%
Cust Acct Fct	C6	77.84%	15.20%	5.58%	0.53%	0.60%	0.26%	100.00%
Bad Debt	C7	65.66%	11.65%	16.36%	1.57%	4.70%	0.06%	100.00%
Cust Serv Fct	C8	21.41%	6.20%	24.33%	16.07%	31.94%	0.05%	100.00%
Avg Cust	C10	84.68%	12.16%	2.30%	0.38%	0.20%	0.28%	100.00%

MAUI ELECTRIC COMPANY, INC. - Lanai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007
SUMMARY OF ALLOCATION FACTORS

ALLOCATION BASIS		Schedule R	Schedule G	Schedule J	Schedule H	Schedule P	Schedule F	Total
Demand Allocation Factors:								
Average-Excess Demand	D1	34.78%	6.33%	21.89%	1.49%	34.90%	0.61%	100.00%
Class Peak Demand	D2	35.15%	6.32%	21.93%	1.48%	34.50%	0.62%	100.00%
Composite NCD	D3	51.32%	7.48%	33.88%	1.45%	5.29%	0.58%	100.00%
Energy Allocation Factors:								
Gross Input	E1	27.67%	6.59%	21.01%	1.84%	42.50%	0.38%	100.00%
Customer Allocation Factors:								
Primary Lines	C1	82.08%	13.05%	3.98%	0.36%	0.36%	0.18%	100.00%
Secondary Lines	C2	84.32%	12.13%	2.83%	0.29%	0.25%	0.18%	100.00%
Transformers	C3	78.89%	14.38%	5.38%	0.64%	0.54%	0.17%	100.00%
Services	C4	83.60%	12.03%	2.83%	0.28%	1.07%	0.18%	100.00%
Meter	C5	82.75%	12.81%	2.82%	0.29%	1.14%	0.18%	100.00%
Cust Acct Fct	C6	79.69%	13.98%	5.25%	0.32%	0.57%	0.19%	100.00%
Bad Debt	C7	88.35%	11.65%	0.00%	0.00%	0.00%	0.00%	100.00%
Cust Serv Fct	C8	5.00%	5.00%	30.00%	20.00%	40.00%	0.00%	100.00%
Avg Cust	C10	85.43%	11.71%	2.24%	0.25%	0.19%	0.19%	100.00%

MAUI ELECTRIC COMPANY, INC. - Molokai Division
DOCKET NO. 2006-0387, TEST-YEAR 2007
SUMMARY OF ALLOCATION FACTORS

ALLOCATION BASIS		Schedule R	Schedule G	Schedule J	Schedule H	Schedule P	Schedule F	Total
Demand Allocation Factors:								
Average-Excess Demand	D1	37.28%	12.30%	19.73%	5.69%	23.43%	1.57%	100.00%
Class Peak Demand	D2	38.08%	13.12%	18.47%	5.81%	22.81%	1.71%	100.00%
Composite NCD	D3	46.43%	12.97%	16.50%	4.80%	18.01%	1.29%	100.00%
Energy Allocation Factors:								
Gross Input	E1	35.84%	10.84%	22.00%	5.47%	24.54%	1.31%	100.00%
Customer Allocation Factors:								
Primary Lines	C1	76.06%	17.08%	4.08%	1.67%	0.84%	0.27%	100.00%
Secondary Lines	C2	79.33%	15.51%	3.05%	1.25%	0.58%	0.28%	100.00%
Transformers	C3	71.35%	18.73%	5.36%	0.90%	3.41%	0.25%	100.00%
Services	C4	77.74%	15.20%	3.04%	1.21%	2.53%	0.27%	100.00%
Meter	C5	76.35%	16.04%	3.08%	1.23%	3.04%	0.27%	100.00%
Cust Acct Fct	C6	70.38%	20.90%	5.94%	1.45%	1.09%	0.25%	100.00%
Bad Debt	C7	70.27%	13.35%	11.13%	2.54%	2.69%	0.02%	100.00%
Cust Serv Fct	C8	5.00%	5.00%	30.00%	20.00%	40.00%	0.00%	100.00%
Avg Cust	C10	81.06%	14.68%	2.52%	1.02%	0.45%	0.29%	100.00%

MAUI ELECTRIC COMPANY - Maui Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
ENERGY LOSS ANALYSIS BY RATE CLASS

Line		Total System	R	G	J-Primary	J-Secondary	Total J	H	P-TP	P-TS	P-DP	P-DS	P-SEC	Total P	E
1	ENERGY SALES	1,212,929	430,167	96,193	2,998	265,195	268,193	21,075	0	2,771	138,029	43,927	207,234	391,961	5,340
	LINE, TRANSFORMER LOSSES:														
2	GENERATOR STEP UP	5,037	1,786	399	12	1,101	1,114	88	0	12	573	182	861	1,628	22
3	TRANSMISSION LINE LOSS	27,404	9,719	2,173	68	5,992	6,059	476	0	63	3,119	992	4,682	8,856	121
4	TRANM TO PRIMARY TRANSFR	7,980	2,830	633	20	1,745	1,765	139	0	18	908	289	1,363	2,579	35
5	PRIMARY LINE LOSS	37,944	13,457	3,009	94	8,296	8,390	659	0	87	4,318	1,374	6,483	12,262	167
6	PRIMARY TO SECNDRY TRANSF	8,281	3,332	745	0	2,054	2,054	163	0	0	0	340	1,605	1,945	41
7	SECONDARY LINE LOSS	7,529	3,959	885	0	2,441	2,441	194	0	0	0	0	0	0	49
8	TOTAL LINE AND TRSFMR LOSS	94,176	35,084	7,845	194	21,629	21,823	1,719	0	179	8,918	3,178	14,994	27,270	436
9	COMPANY USE	1,662	589	132	4	363	367	29	0	4	189	60	284	537	7
10	UNACCOUNTED FOR	-17,336	-6,148	-1,375	-43	-3,790	-3,833	-301	0	-40	-1,973	-628	-2,962	-5,602	-76
11	NET INPUT	1,291,431	459,692	102,795	3,153	283,397	286,550	22,522	0	2,914	145,163	46,538	219,550	414,166	5,707
12	LESS PURCHASED POWER	214,214	76,251	17,051	523	47,008	47,531	3,736	0	483	24,079	7,719	36,418	68,699	947
13	NET GENERATION	1,077,217	383,441	85,744	2,630	236,389	239,019	18,786	0	2,431	121,085	38,818	183,133	345,466	4,760
14	STATION USE	21,686	7,719	1,726	53	4,759	4,812	378	0	49	2,438	781	3,687	6,955	96
15	GROSS GENERATION	1,098,903	391,161	87,470	2,683	241,148	243,831	19,164	0	2,480	123,522	39,600	186,820	352,421	4,856
16	PLUS PURCHASED POWER	214,214	76,251	17,051	523	47,008	47,531	3,736	0	483	24,079	7,719	36,418	68,699	947
	GROSS INPUT BY VOLTAGE:														
17	GROSS I	1,313,117	467,411	104,521	3,206	288,156	291,362	22,900	0	2,963	147,601	47,319	223,237	421,120	5,802
18	GROSS II	1,310,154	467,411	104,521	3,206	288,156	291,362	22,900	0	0	147,601	47,319	223,237	418,157	5,802
19	GROSS III	1,112,028	467,411	104,521	0	288,156	288,156	22,900	0	0	0	0	223,237	223,237	5,802
20	GROSS TO SALES RATIO	1.0826	1.0866	1.0866	1.0693	1.0866	1.0864	1.0866	0.0000	1.0693	1.0693	1.0772	1.0772	1.0744	1.0866
21	NET TO SALES RATIO	1.0647	1.0686	1.0686	1.0517	1.0686	1.0684	1.0686	0.0000	1.0517	1.0517	1.0594	1.0594	1.0566	1.0686

Line	Derivation:	Line	Basis	Line	Basis
1	TEST YEAR FORECAST	8	Sum(L2 thru L7)	15	L13+L14
2	NET GENERATION * % SALES * 0.0039	9	% of SALES	16	L12
3	NET INPUT * % SALES * 0.0182	10	% of SALES	17	L15+L16
4	NET INPUT * % SALES * 0.0053	11	L1+L8+L9+L10	18	L17 EXCL TRANS
5	NET INPUT * % SALES * 0.0252	12	% of NET INPUT	19	L17 EXCL TRANS.PRIMY
6	NET INPUT * % SALES EXCL DP * 0.0055	13	L11 - L12	20	L17 ÷ L1
7	NET INPUT * % SALES EXCL DP,DS,PSEC * 0.005	14	% of NET GENRTN	21	L11 ÷ L1

MAUI ELECTRIC COMPANY - Lanai Division
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ENERGY LOSS ANALYSIS BY RATE CLASS

Line		Total System	R	G	J-Primary	J-Secondary	Total J	H	P-TP	P-TS	P-DP	P-DS	P-SEC	Total P	E
1	ENERGY SALES	29,779	8,183	1,949	0	6,215	6,215	545	0	0	10,803	0	1,971	12,774	114
	LINE, TRANSFORMER LOSSES:														
2	GENERATOR STEP UP	122	34	8	0	26	26	2	0	0	44	0	8	53	0
3	TRANSMISSION LINE LOSS	571	157	37	0	119	119	10	0	0	207	0	38	245	2
4	TRANM TO PRIMARY TRANSFR	166	46	11	0	35	35	3	0	0	60	0	11	71	1
5	PRIMARY LINE LOSS	791	217	52	0	165	165	14	0	0	287	0	52	339	3
6	PRIMARY TO SECNDRY TRANSF	173	74	18	0	57	57	5	0	0	0	0	18	18	1
7	SECONDARY LINE LOSS	157	76	18	0	57	57	5	0	0	0	0	0	0	1
8	TOTAL LINE AND TRSFMR LOSS	1,981	604	144	0	458	458	40	0	0	599	0	127	726	8
9	COMPANY USE	8	2	0	0	2	2	0	0	0	3	0	1	3	0
10	UNACCOUNTED FOR	-379	-104	-25	0	-79	-79	-7	0	0	-138	0	-25	-163	-1
11	NET INPUT	31,389	8,684	2,069	0	6,596	6,596	578	0	0	11,267	0	2,074	13,341	121
12	LESS PURCHASED POWER	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	NET GENERATION	31,389	8,684	2,069	0	6,596	6,596	578	0	0	11,267	0	2,074	13,341	121
14	STATION USE	1,012	280	67	0	213	213	19	0	0	363	0	67	430	4
15	GROSS GENERATION	32,400	8,964	2,136	0	6,808	6,808	597	0	0	11,630	0	2,141	13,771	125
16	PLUS PURCHASED POWER	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	GROSS INPUT BY VOLTAGE:														
17	GROSS I	32,400	8,964	2,136	0	6,808	6,808	597	0	0	11,630	0	2,141	13,771	125
18	GROSS II	32,400	8,964	2,136	0	6,808	6,808	597	0	0	11,630	0	2,141	13,771	125
19	GROSS III	20,770	8,964	2,136	0	6,808	6,808	597	0	0	0	0	2,141	2,141	125
20	GROSS TO SALES RATIO	1.0880	1.0955	1.0955	0.0000	1.0955	1.0955	1.0955	0.0000	0.0000	1.0766	0.0000	1.0860	1.0780	1.0955
21	NET TO SALES RATIO	1.0540	1.0613	1.0613	0.0000	1.0613	1.0613	1.0613	0.0000	0.0000	1.0430	0.0000	1.0521	1.0444	1.0613

Line	Derivation:	Line	Basis	Line	Basis
1	TEST YEAR FORECAST	8	Sum(L2 thru L7)	15	L13+L14
2	NET GENERATION * % SALES * 0.0039	9	% of SALES	16	L12
3	NET INPUT * % SALES * 0.0182	10	% of SALES	17	L15+L16
4	NET INPUT * % SALES * 0.0053	11	L1+L8+L9+L10	18	L17 EXCL TRANS
5	NET INPUT * % SALES * 0.0252	12	% of NET INPUT	19	L17 EXCL TRANS PRMY
6	NET INPUT * % SALES EXCL DP * 0.0055	13	L11 - L12	20	L17 ÷ L1
7	NET INPUT * % SALES EXCL DP,DS,PSEC * 0.005	14	% of NET GENRTN	21	L11 ÷ L1

MAUI ELECTRIC COMPANY - Molokai Division
DOCKET NO. 2006-0387 TEST-YEAR 2007
ENERGY LOSS ANALYSIS BY RATE CLASS

Line		Total System	R	G	J-Primary	J-Secondary	Total J	H	P-TP	P-TS	P-DP	P-DS	P-SEC	Total P	E
1	*ENERGY SALES*	36,548	13,077	3,954	0	8,025	8,025	1,994	0	0	1,102	0	7,917	9,019	479
	LINE, TRANSFORMER LOSSES:														
2	GENERATOR STEP UP	157	56	17	0	34	34	9	0	0	5	0	34	39	2
3	TRANSMISSION LINE LOSS	732	262	79	0	161	161	40	0	0	22	0	158	181	10
4	TRANM TO PRIMARY TRANSFR	213	76	23	0	47	47	12	0	0	6	0	46	53	3
5	PRIMARY LINE LOSS	1,013	362	110	0	222	222	55	0	0	31	0	219	250	13
6	PRIMARY TO SECNDRY TRANSF	221	82	25	0	50	50	12	0	0	0	0	49	49	3
7	SECONDARY LINE LOSS	201	95	29	0	59	59	15	0	0	0	0	0	0	3
8	TOTAL LINE AND TRSFMR LOSS	2,537	934	282	0	573	573	142	0	0	64	0	507	571	34
9	COMPANY USE	132	47	14	0	29	29	7	0	0	4	0	29	32	2
10	UNACCOUNTED FOR	982	351	106	0	216	216	54	0	0	30	0	213	242	13
11	NET INPUT	40,198	14,409	4,357	0	8,843	8,843	2,197	0	0	1,200	0	8,666	9,865	527
12	LESS PURCHASED POWER	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	NET GENERATION	40,198	14,409	4,357	0	8,843	8,843	2,197	0	0	1,200	0	8,666	9,865	527
14	STATION USE	1,322	474	143	0	291	291	72	0	0	39	0	285	325	17
15	GROSS GENERATION	41,521	14,883	4,500	0	9,133	9,133	2,270	0	0	1,239	0	8,951	10,190	545
16	PLUS PURCHASED POWER	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	GROSS INPUT BY VOLTAGE:														
17	GROSS I	41,521	14,883	4,500	0	9,133	9,133	2,270	0	0	1,239	0	8,951	10,190	545
18	GROSS II	41,521	14,883	4,500	0	9,133	9,133	2,270	0	0	1,239	0	8,951	10,190	545
19	GROSS III	40,282	14,883	4,500	0	9,133	9,133	2,270	0	0	0	0	8,951	8,951	545
20	GROSS TO SALES RATIO	1.1361	1.1381	1.1381	0.0000	1.1381	1.1381	1.1381	0.0000	0.0000	1.1241	0.0000	1.1306	1.1298	1.1381
21	NET TO SALES RATIO	1.0999	1.1019	1.1019	0.0000	1.1019	1.1019	1.1019	0.0000	0.0000	1.0883	0.0000	1.0946	1.0938	1.1019

Line	Derivation:	Line	Basis	Line	Basis
1	TEST YEAR FORECAST	8	Sum(L2 thru L7)	15	L13+L14
2	NET GENERATION * % SALES * 0.0039	9	% of SALES	16	L12
3	NET INPUT * % SALES * 0.0182	10	% of SALES	17	L15+L16
4	NET INPUT * % SALES * 0.0053	11	L1+L8+L9+L10	18	L17 EXCL TRANS
5	NET INPUT * % SALES * 0.0252	12	% of NET INPUT	19	L17 EXCL TRANS.PRIMY
6	NET INPUT * % SALES EXCL DP * 0.0055	13	L11 - L12	20	L17 ÷ L1
7	NET INPUT * % SALES EXCL DP.DS.PSEC * 0.005	14	% of NET GENRTN	21	L11 ÷ L1

MAUI ELECTRIC COMPANY, LTD.
DOCKET NO. 2006-0387, TEST-YEAR 2007
MARGINAL COST STUDY

MARGINAL ENERGY COSTS BY TIME-OF-USE RATING PERIOD

YEAR	Priority Peak	Mid-Peak	Off-Peak	TOTAL
	(A)	(B)	(C)	(D)
		Transmission Voltage Service (¢/kWh)		
2007	19.78	19.62	18.47	19.15
2008	15.22	14.95	14.14	14.64
2009	14.63	14.32	13.61	14.05
2010	14.18	13.76	13.08	13.53
2011	13.67	13.44	12.83	13.21
		Primary Voltage Service (¢/kWh)		
2007	21.06	20.77	19.18	20.12
2008	16.19	15.81	14.68	15.37
2009	15.55	15.13	14.12	14.75
2010	15.07	14.53	13.58	14.19
2011	14.52	14.19	13.31	13.85
		Secondary Voltage Service (¢/kWh)		
2007	21.29	20.97	19.31	20.30
2008	16.37	15.96	14.78	15.50
2009	15.72	15.28	14.21	14.87
2010	15.23	14.67	13.66	14.30
2011	14.67	14.32	13.39	13.96
Average	16.65	16.24	15.07	15.79

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
DOCKET NO. 2006-0387, TEST-YEAR 2007

DETERMINATION OF BASE FUEL ENERGY CHARGE

In Cents Per kWh

L1	Weighted Base Central Station + Other Generation Cost	13.74794	MECO-1906, line 19
L2	Revenue Tax Requirements Multiplier	1.0975	MECO-1906, line 21
L3 = L1 * L2	Base Central Station + Other Generation Cost at Revenue Level	15.08836	
L4	Weighted Base DG (Distributed Generation) Energy Cost	0.00223	MECO-1906, line 28
L5	Loss Factor	1.065	MECO-1906, line 30
L6	Revenue Tax Requirements Multiplier	1.0975	MECO-1906, line 31
L7 = L4*L5*L6	Base DG Energy Cost at Revenue Level	0.00261	
L8	Weighted Base Purchased Energy Cost	2.48816	MECO-1906, line 61
L9	Loss Factor	1.065	MECO-1906, line 63
L10	Revenue Tax Requirements Multiplier	1.0975	MECO-1906, line 64
L11 = L8*L9*L10	Base Purchased Energy Cost at Revenue Level	2.90825	
L12 = L3+L7+L11	Base Fuel Energy Charge	17.9992	

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
DOCKET NO. 2006-0387, TEST-YEAR 2007

DETERMINATION OF BASE FUEL ENERGY CHARGE

In Cents Per kWh

L1	Weighted Base Central Station + Other Generation Cost	20.73557	MECO-1910, line 19
L2	Revenue Tax Requirements Multiplier	1.0975	MECO-1910, line 21
L3 = L1 * L2	Base Central Station + Other Generation Cost at Revenue Level	22.75729	
L4	Weighted Base DG (Distributed Generation) Energy Cost	0	MECO-1910, line 28
L5	Loss Factor	1.054	MECO-1910, line 30
L6	Revenue Tax Requirements Multiplier	1.0975	MECO-1910, line 31
L7 = L4*L5*L6	Base DG Energy Cost at Revenue Level	0.00000	
L8	Weighted Base Purchased Energy Cost	0	MECO-1910, line 47
L9	Loss Factor	1.054	MECO-1910, line 49
L10	Revenue Tax Requirements Multiplier	1.0975	MECO-1910, line 50
L11 = L8*L9*L10	Base Purchased Energy Cost at Revenue Level	0.00000	
L12 = L3+L7+L11	Base Fuel Energy Charge	22.7573	

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
DOCKET NO. 2006-0387, TEST-YEAR 2007

DETERMINATION OF BASE FUEL ENERGY CHARGE

In Cents Per kWh

L1	Weighted Base Central Station + Other Generation Cost	19.84397	MECO-1912, line 19
L2	Revenue Tax Requirements Multiplier	1.0975	MECO-1912, line 21
L3 = L1 * L2	Base Central Station + Other Generation Cost at Revenue Level	21.77876	
L4	Weighted Base DG (Distributed Generation) Energy Cost	0	MECO-1912, line 28
L5	Loss Factor	1.100	MECO-1912, line 30
L6	Revenue Tax Requirements Multiplier	1.0975	MECO-1912, line 31
L7 = L4*L5*L6	Base DG Energy Cost at Revenue Level	0.00000	
L8	Weighted Base Purchased Energy Cost	0	MECO-1912, line 47
L9	Loss Factor	1.100	MECO-1912, line 49
L10	Revenue Tax Requirements Multiplier	1.0975	MECO-1912, line 50
L11 = L8*L9*L10	Base Purchased Energy Cost at Revenue Level	0.00000	
L12 = L3+L7+L11	Base Fuel Energy Charge	21.7788	

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
DOCKET NO. 2006-0387, TEST-YEAR 2007

DISTRIBUTION OF CUSTOMERS AND KWH IN PROPOSED USAGE TIERS

Non-Fuel Energy Charge Tier	% of Customer Bills in Tier	% of Cumulative kWh in Tier
0 to 350 kWh	25.8%	45.7%
350 to 1200 kWh	62.1%	43.3%
Over 1200 kWh	12.1%	11.0%
Total	100.0%	100.0%

Source: MECO Billing Data, January 2005 - December 2005

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
DOCKET NO. 2006-0387, TEST-YEAR 2007

DISTRIBUTION OF CUSTOMERS AND KWH IN PROPOSED USAGE TIERS

Non-Fuel Energy Charge Tier	% of Customer Bills in Tier	% of Cumulative kWh in Tier
0 to 350 kWh	28.5%	46.5%
350 to 1200 kWh	57.5%	39.5%
Over 1200 kWh	14.0%	14.0%
Total	100.0%	100.0%

Source: MECO Billing Data, January 2005 - December 2005

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
DOCKET NO. 2006-0387, TEST-YEAR 2007

DISTRIBUTION OF CUSTOMERS AND KWH IN PROPOSED USAGE TIERS

Non-Fuel Energy Charge Tier	% of Customer Bills in Tier	% of Cumulative kWh in Tier
0 to 350 kWh	31.0%	50.3%
350 to 1200 kWh	55.0%	39.5%
Over 1200 kWh	14.0%	10.2%
Total	100.0%	100.0%

Source: MECO Billing Data, January 2005 - December 2005

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
SCHEDULE R - RESIDENTIAL SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	UNITS BILLED (MWH)	UNIT PRICE $/KWH	REVENUES $1000s	UNIT PRICE $/KWH	REVENUES $1000s
ENERGY CHARGE:					
NON-FUEL ENERGY CHG	430167	8.8294	37,981.2		
0-350 kWh	194918			10.3229	20,121.2
351-1200 kWh	187226			11.1375	20,852.3
Over 1200 kWh	48023			11.6756	5,607.0
SUBTOTAL NON-FUEL ENERGY			37,981.2		46,580.5
BASE FUEL CHG.	430167	4.5937	19,760.6	17.9992	77,426.6
SUBTOTAL ENERGY			57,741.8		124,007.1
CUSTOMER CHARGE:	BILLS	$/MONTH		$/MONTH	
1 Phase	616590	7.50	4,624.4	7.50	4,624.4
3 Phase	185	12.00	2.2	12.00	2.2
SUBTOTAL			4,626.6		4,626.6
ADJUSTMENTS:					
SCHEDULE E ADJ.			(285.4)		(143.9)
10% APT-HSE.			(204.2)		(205.0)
MINIMUM			59.7		58.1
SUBTOTAL			(429.9)		(290.8)
UNADJUSTED BASE REV.:			61,938.5		128,342.9
	(MWH)	$/KWH		$/KWH	
FUEL OIL ADJ.:	430167	13.9540	60,025.5	0.0000	0.0
TEMP RATE DECR.:		0.0000	0.0	0.0000	0.0
FIRM CAP. SURC. ADJ.		(0.0769)	(47.8)	0.0000	0.0
UNADJUSTED TOTAL REV.			121,916.2		128,342.9
INTERIM RATE INCREASE:			0.0		0.0
TOTAL REVENUES			121,916.2		128,342.9

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
SCHEDULE G - GENERAL SERVICE NON-DEMAND
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE ¢/KWH	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE ¢/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:					
G: NON-DEMAND	96,192.9	14.5656	14,011.1	29.8037	28,669.0
	BILLS	$/BILL			
CUSTOMER CHARGE:					
1 PHASE	55,404	21.00	1,163.5	25.00	1,385.1
3 PHASE	33,168	36.00	1,194.0	40.00	1,326.7
SUBTOTAL	88572		2,357.5		2,711.8
ADJUSTMENTS:					
PRIMARY SERVICE			0.0		0.0
SECONDARY SERVICE			0.0		0.0
MINIMUM BILL ADJ.			34.1		33.8
SUBTOTAL			34.1		33.8
UNADJUSTED BASE REV.			16,402.7		31,414.6
	MWH	¢/KWH		¢/KWH	
FUEL OIL ADJ.	96192.9	13.9540	13,422.8	0.0000	0.0
TEMP RATE DECR.		0	0.0	0.0000	0.0
FIRM CAP. SURCHARGE		(0.0769)	(12.6)	0.0000	0.0
UNADJUSTED TOTAL REV.			29,812.9		31,414.6
SCHEDULE E ADJ.			0.0		(30.2)
INTERIM INCREASE			0.0		0.0
TOTAL REVENUES			29,812.9		31,384.4

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
SCHEDULE J - GENERAL SERVICE DEMAND
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	PRESENT RATES			PRESENT RATES		
	BILLING UNITS (MWH)	UNIT PRICE ¢/KWH	REVENUES $1000S	BILLING UNITS (MWH)	UNIT PRICE ¢/KWH	REVENUES $1000S
ENERGY CHARGE						
0 - 200 KWH/KW	163,741.2	12.4165	20330.9	170,268.7	25.5003	43,419.0
201 - 400 KWH/KW	87,396.2	11.4024	9965.3	79,655.5	24.4862	19,504.6
> 400 KWH/KW	17,055.5	8.4403	1,439.5	18,268.7	21.5241	3,932.2
TOTAL	268,192.9		31,735.7	268,192.9		66,855.8
DEMAND CHARGE		$/KW			$/KW	
ALL BILLING KW	916366	5.75	5,269.1	946751	12.00	11,361.0
CUSTOMER CHARGE		$/BILL			$/BILL	
1 PHASE	1590	35.00	55.7	1590	50.00	79.5
3 PHASE	15114	50.00	755.7	15114	65.00	982.4
SUBTOTAL	16,704		811.4	16,704		1,061.9
ADJUSTMENTS		¢/KWH				
FUEL OIL ADJUSTMENT	268192.9	13.9540	37,423.6		0.0000	0.0
TEMP RATE DECR.	268192.9	0.0000	0.0		0.0000	0.0
POWER FACTOR ADJUSTMENT			7.6			16.7
PRIMARY ADJUSTMENT (DP)			(9.1)			(10.5)
SECONDARY ADJUSTMENT (DS)			(1.4)			(1.4)
RIDER T ADJ			(176.3)			(243.4)
RIDER M ADJ			(2.1)			(4.5)
FCS NET	268192.9	(0.0769)	(28.9)	0	0.0000	0.0
SUBTOTAL			37,213.4			(243.1)
UNADJUSTED TOTAL REVENUE			75,029.6			79,035.6
SCHEDULE E ADJ.:						(51.0)
INTERIM RATE INCREASE:			0.0			0.0
TOTAL REVENUES			75,029.6			78,984.6

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
SCHEDULE H - COMMERCIAL COOKING, HEATING, AIR CONDITIONING, AND REFRIGERATION SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
	MWH	¢/KWH		¢/KWH	
ENERGY CHARGE:	21075	11.9675	2,522.2	26.3728	5558.1
	KW	$/KW		$/KW	
CAPACITY CHARGE:	74,581	4.50	335.6	7.00	522.1
CUSTOMER CHARGE:	0.089	$/BILL		$/BILL	
1 PHASE	430	27.00	11.6	40.00	17.2
3 PHASE	2,366	43.00	101.7	55.00	130.1
SUBTOTAL	2796		113.3		147.3
UNADJUSTED BASE REV.			2,971.1		6227.5
	MWH	¢/KWH		¢/KWH	
FUEL OIL ADJ.:	21075	13.9540	2,940.8	0.000	0.0
TEMP RATE DECR.:	21075	0.0000	0.0	0.000	0.0
fcs net	21075	(0.0769)	(2.3)	0.000	0.0
SCHEDULE E ADJ.			0.0		-6.3
UNADJUSTED REVENUES			5909.6		6,221.2
INTERIM RATE INCREASE			0.0		0.0
TOTAL REVENUES			5,909.6		6,221.2

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
SCHEDULE P - LARGE POWER SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES FOR TOTAL CLASS

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	¢/KWH		¢/KWH	
0 - 200 KWH/KW	162,977	10.9997	17,927.0	24.4694	39,879.5
201 - 400 KWH/KW	145,104	9.4576	13,723.4	22.9273	33,268.4
> 400 KWH/KW	83,880	7.7456	6,497.0	21.2153	17,795.4
SUBTOTAL	391961		38,147.4		90,943.3
DEMAND CHARGE:	(KW)	$/KW		$/KW	
0 - 500 KW	535,091	8.50	4,548.3	18.00	9,631.6
> 500 KW	287,746	8.00	2,302.0	17.00	4,891.7
SUBTOTAL	822,837		6,850.3		14,523.3
CUSTOMER CHARGE:	BILLS	$/BILL		$/BILL	
	1452	225.00	326.7	375.00	544.5
ADJUSTMENTS:					
PF			(360.0)		(843.7)
TP					
DP			(312.9)		(405.2)
TS			(12.1)		(27.9)
DS			(49.4)		(58.2)
SUBTOTAL			(734.4)		(1,335.0)
RIDER T			-115.1		(158.2)
RIDER I			0		0
RIDER M			-149.3		-251.1
SUBTOTAL			-264.4		-409.3
UNADJUSTED BASE REV.			44,325.6		104,266.8
		¢/KWH			
FUEL OIL REV.	391961	13.9540	54,694.2	0.0000	0.0
TEMP RATE DECR.		0.0000	0.0	0.0000	0.0
FIRM CAP. SURCHARGE		(0.0769)	(34.1)	0.0000	0.0
UNADJUSTED TOTAL REV.			98,985.7		104266.8
SCHEDULE E ADJ.			0		(63.3)
INTERIM RATE INCREASE			0.0		0
TOTAL REVENUES			98,985.7		104,203.5

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
SCHEDULE F - PUBLIC STREET LIGHTING SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE CENTS/KWH	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE CENTS/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:					
0 - 150 KWH/KW	2,350.8	15.1733	356.7	30.5954	719.2
> 150 KWH/KW	2,989.2	10.6753	319.1	26.0974	780.1
SUBTOTAL	5,340.0		675.8		1,499.3
FUEL OIL ADJ.:	5,340.0	13.9540	745.1	0.0000	0.0
TEMP RATE DECR.:	5,340.0	0	0.0	0.0000	0.0
SUBTOTAL			745.1		0
UNADJUSTED TOTAL REV.:			1,420.9		1,499.3
MINIMUM CHARGE ADJ.			0.8		0.7
SCHEDULE E ADJ.			0.0		(3.9)
FIRM CAP. SURC. ADJ.:	5,340.0	(0.0769)	(0.5)		
INTERIM RATE INCREASE			0.0		0
TOTAL REVENUES			1,421.2		1,496.1

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
SCHEDULE R - RESIDENTIAL SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE $/KWH	PRESENT RATES REVENUES $1000s	PROPOSED RATES UNIT PRICE $/KWH	PROPOSED RATES REVENUES $1000s
ENERGY CHARGE:					
NON-FUEL ENERGY CHG	8182.7	9.0028	736.7		
BASE FUEL CHG.	8182.7	9.0620	741.5		
SUBTOTAL ENERGY			1,478.2		
ENERGY CHARGE:					
BASE FUEL CHG.	8182.7			22.7573	1,862.2
NON-FUEL ENERGY CHG.					
0-250 kWh	3664.4			10.4932	384.5
250-750 kWh	3291.6			10.9998	362.1
Over 750 kWh	1226.7			11.7853	144.6
SUBTOTAL ENERGY		8182.7			2,753.4
CUSTOMER CHARGE:	BILLS	$/MONTH		$/MONTH	
1 Phase	16452	7.50	123.4	7.50	123.4
3 Phase	12	12.00	0.1	12.00	0.1
SUBTOTAL CUSTOMER			123.5		123.5
SUBTOTAL ENERGY + CUSTOMER			1,601.7		2,876.9
ADJUSTMENTS:					
SCHEDULE E ADJ.			(10.0)		(4.3)
10% APT-HSE.			0.0		0.0
Adjustment			(1.8)		0.0
MINIMUM			3.2		3.1
SUBTOTAL			(8.6)		(1.2)
UNADJUSTED BASE REV.:			1,593.1		2,875.7
	(MWH)	$/KWH		$/KWH	
FUEL OIL ADJ.:	8182.7	13.9130	1,138.5	0.0000	0.0
UNADJUSTED TOTAL REV.			2,731.6		2,875.7
INTERIM INCREASE			0.0		0.0
TOTAL REVENUES			2,731.6		2,875.7

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
SCHEDULE G - GENERAL SERVICE NON-DEMAND
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE ¢/KWH	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE ¢/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:					
G: NON-DEMAND	1,949.4	20.4188	398.0	35.4062	690.2
	BILLS	$/BILL			
CUSTOMER CHARGE:					
1 PHASE	1,906	22.00	41.9	30.00	57.2
3 PHASE	350	38.00	13.3	45.00	15.8
SUBTOTAL	2256		55.2		73.0
ADJUSTMENTS:					
PRIMARY SVC			0		0.0
SECONDARY SVC			0.0		0.0
MIN. BILL ADJ.			0.8		0.9
SUBTOTAL			0.8		0.9
UNADJUSTED BASE REV.			454.0		764.1
	MWH	¢/KWH		¢/KWH	
FUEL OIL ADJ.	1949.4	13.9130	271.2	0.0000	0.0
TEMP RATE DECR.		0.0000	0.0	0.0000	0.0
SCHEDULE E ADJ.			0.0		(0.8)
UNADJUSTED TOTAL REV.			725.2		763.3
INTERIM INCREASE			0		0.0
TOTAL REVENUES			725.2		763.3

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
SCHEDULE J - GENERAL SERVICE DEMAND
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE ¢/KWH	PRESENT RATES REVENUES $1000S	BILLING UNITS (MWH)	PROPOSED RATES UNIT PRICE ¢/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE						
0 - 200 KWH/KW	3,787.9	20.6089	780.6	4,101.6	34.9321	1,432.8
201 - 400 KWH/KW	2,062.5	19.4319	400.8	2,033.4	33.7551	686.4
> 400 KWH/KW	364.2	16.4719	60.0	79.6	30.7951	24.5
TOTAL	6,214.6		1,241.4	6,214.6		2,143.7
DEMAND CHARGE		$/KW			$/KW	
ALL BILLING KW	22,108	5.75	127.1	22,898	9.00	206.1
CUSTOMER CHARGE		$/BILL			$/BILL	
1 PHASE	65	35.00	2.3	65	45.00	2.9
3 PHASE	367	50.00	18.4	367	60.00	22.0
SUBTOTAL	432		20.7	432		24.9
ADJUSTMENTS		¢/KWH				
FUEL OIL ADJ.	6,214.6	13.9130	864.6	6,214.6	0.0000	0.0
TEMP RATE DECREASE	6,214.6	0.0000	0.0	6,214.6	0.0000	0.0
PRIMARY ADJ. (DP)			0.0			0.0
SECONDARY ADJ.(DS)			0.0			0.0
POWER FACTOR ADJ. (PF)			0.0			0.0
SCHEDULE E ADJ.			0.0			(2.0)
REVENUE ADJ.			0.0			0.0
SUBTOTAL			864.6			(2.0)
UNADJUSTED TOTAL REVENUE			2,253.8			2,372.7
RIDER T ADJ			0.0			0.0
RIDER I ADJ			0.0			0.0
RIDER M(B) ADJ			0.0			0.0
INTERIM RATE INCREASE			0.0			
TOTAL REVENUES			2,253.8			2,372.7

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
SCHEDULE H - COMMERCIAL COOKING, HEATING, AIR CONDITIONING, AND REFRIGERATION SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
	MWH	¢/KWH		¢/KWH	
ENERGY CHARGE:	545	18.0021	98.1	32.8358	179
	KW	$/KW		$/KW	
CAPACITY CHARGE:	1,101	4.50	5.0	8.00	8.8
CUSTOMER CHARGE:	BILLS	$/BILL		$/BILL	
1 PHASE	24	27.00	0.6	40.00	1.0
3 PHASE	24	43.00	1.0	55.00	1.3
SUBTOTAL	48		1.6		2.3
UNADJUSTED BASE REV.			104.7		190.1
	MWH	¢/KWH		¢/KWH	
FUEL OIL ADJ.:	545	13.9130	75.8	0.000	0.0
TEMP RATE DECR.:	545	0.0000	0.0	0.000	0.0
SCHEDULE E ADJ.			0.0		-0.1
UNADJUSTED REVENUES			180.5		190
INTERIM INCREASE			0.0		0
TOTAL REVENUES			180.5		190.0

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
SCHEDULE P - LARGE POWER SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES FOR TOTAL CLASS

	PRESENT RATES			PROPOSED RATES		
	BILLING UNITS	UNIT PRICE	REVENUES $1000s	BILLING UNITS	UNIT PRICE	REVENUES $1000s
ENERGY CHARGE:	(MWH)	¢/KWH		(MWH)	¢/KWH	
0 - 200 KWH/KW	3,852.6	18.8358	725.7	3,852.6	32.1715	1,239.4
201 - 400 KWH/KW	3,852.6	17.2958	666.3	3,852.6	30.6315	1,180.1
> 400 KWH/KW	2,257.5	15.5858	351.8	2,257.5	28.9215	652.9
SUBTOTAL	9,962.7		1,743.8	9,962.7		3072.4
DEMAND CHARGE:	(KW)	$/KW		(KW)	$/KW	
0 - 500 KW	10,754	8.50	91.4	10,754	22.00	236.6
501 - 1500 KW	8,671	8.00	69.4	8,671	20.00	173.4
1501 - 5000 KW	0	8.00	0.0	0	20.00	0.0
> 5000 KW	0	8.00	0.0	0	20.00	0.0
SUBTOTAL	19,425		160.8	19,425		410.0
	BILLS	$/BILL		BILLS	$/BILL	
CUSTOMER CHARGE:	24	200.00	4.8	24	200.00	4.8
SUBTOTAL			1,909.4			3,487.2
SPECIAL CONTRACT			894.7			941.9
	(MWH)	¢/KWH		(MWH)		
FUEL OIL REV.	9962.7	13.9130	1,386.1	9962.7	0.0000	0.0
DP VOLTAGE ADJ.			(30.5)			-30.7
POWER FACTOR ADJ.			-21			-38.3
TEMP RATE DECR.		0.0000	0.0		0.0000	0.0
SCHEDULE E ADJ.			0.0			(3.1)
REVENUE ADJ.			0			0
INTERIM RATE INCREASE			0.0			
TOTAL REVENUES			4,138.7			4,357.0

L

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
SCHEDULE F - PUBLIC STREET LIGHTING SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE CENTS/KWH	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE CENTS/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:					
0 - 150 KWH/KW	51.0	21.0335	10.7	36.8235	18.8
> 150 KWH/KW	62.0	16.5415	10.3	32.3315	20.0
	113.7		21.0		38.8
ADJUSTMENTS:					
MINIMUM BILL			0.1		0.1
UNADJUSTED BASE REV.:			21.1		38.9
FUEL OIL ADJ.:	113.7	13.9130	15.8	0.0000	0.0
TEMP RATE DECR.:	113.7	0.0000	0.0	0.0000	0.0
SCHEDULE E ADJ.			0.0		(0.1)
SUBTOTAL			15.8		-0.1
UNADJUSTED TOTAL REV.:			36.9		38.8
INTERIM INCREASE			0.0		0.0
TOTAL REVENUES			36.9		38.8

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
SCHEDULE R - RESIDENTIAL SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE $/KWH	PRESENT RATES REVENUES $1000s	PROPOSED RATES UNIT PRICE $/KWH	PROPOSED RATES REVENUES $1000s
ENERGY CHARGE:					
NON-FUEL ENERGY CHG	13077	12.0392	1,574.4		
BASE FUEL CHG.	13077	5.3991	706.0		
SUBTOTAL			2,280.4		
ENERGY CHARGE:					
BASE FUEL CHG.	13077			21.7788	2,848.0
NON-FUEL ENERGY CHG.					
0-250 kWh	6589			12.5944	829.8
250-750 kWh	5356			13.7500	736.5
Over 750 kWh	1132			14.0055	158.5
SUBTOTAL ENERGY		13077			4,572.8
	BILLS	$/MONTH		$/MONTH	
CUSTOMER CHARGE:	30552	7.50	229.1	7.50	229.1
SUBTOTAL			2,509.5		4,801.9
ADJUSTMENTS:					
SCHEDULE E ADJ.			(20.2)		(9.7)
10% APT-HSE.			(4.6)		(4.7)
MINIMUM			9.2		9.5
SUBTOTAL			(15.6)		(4.9)
UNADJUSTED BASE REV.:			2,493.9		4,797.0
	(MWH)	$/KWH		$/KWH	
FUEL OIL ADJ.:	13077	15.7740	2,062.8	0.0000	0.0
UNADJUSTED TOTAL REV.			4,556.7		4,797.0
INTERIM INCREASE			0.0		0.0
TOTAL REVENUES			4,556.7		4,797.0

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
SCHEDULE G - GENERAL SERVICE NON-DEMAND
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE ¢/KWH	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE ¢/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:					
G: NON-DEMAND	3,953.9	23.7929	940.7	41.7728	1,651.7
	BILLS	$/BILL			
CUSTOMER CHARGE:					
1 PHASE	4,181	22.00	92.0	23.00	96.2
3 PHASE	1,351	33.00	44.6	34.00	45.9
SUBTOTAL	5532		136.6		142.1
ADJUSTMENTS:					
DP VOLTAGE SERVICE			0		0.0
DS VOLTAGE SERVICE			0.0		0.0
MINIMUM BILL ADJ.			2.7		2.7
SCHEDULE E ADJ.					(3.0)
SUBTOTAL			2.7		(0.3)
UNADJUSTED BASE REV.			1,080.0		1,793.5
	MWH	¢/KWH		¢/KWH	
FUEL OIL ADJ.	3953.9	15.7740	623.7	0.0000	0.0
FIRM CAP. SURCHARGE		0.0000	0.0	0.0000	0.0
UNADJUSTED TOTAL REV.			1,703.7		1,793.5
TEMP RATE DECR.			0.0		0.0
REVENUE ADJ			0		
INTERIM RATE INCREASE					
TOTAL REVENUES			1,703.7		1,793.5

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
SCHEDULE J - GENERAL SERVICE DEMAND
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE ¢/KWH	PRESENT RATES REVENUES $1000S	BILLING UNITS (MWH)	PROPOSED RATES UNIT PRICE ¢/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE						
0 - 200 KWH/KW	5,016.0	19.6204	984.2	5,087.0	34.7806	1,769.3
201 - 400 KWH/KW	2,370.6	13.7734	326.5	2,269.8	28.9336	656.7
> 400 KWH/KW	638.5	11.9444	76.3	668.3	27.1046	181.1
TOTAL	8,025.1		1,387.0	8,025.1		2,607.1
DEMAND CHARGE		$/KW			$/KW	
ALL BILLING KW	30202	4.75	143.5	30923	11.00	340.2
CUSTOMER CHARGE		$/BILL			$/BILL	
1 PHASE	255	30.00	7.7	255	32.00	8.2
3 PHASE	693	40.00	27.7	693	42.00	29.1
SUBTOTAL	948		35.4	948		37.3
ADJUSTMENTS:		¢/KWH			¢/KWH	
FUEL OIL ADJ	8025.1	15.7740	1,265.9	8025.1	0.0000	0.0
FIRM CAP. SURCHRG	8025.1	0.0000	0.0	8025.1	0.0000	0.0
POWER FACTOR ADJ.			0			0
PRIMARY ADJUSTMENT (DP)			0.0			0.0
SECONDARY ADJUSTMENT (DS)			0.0			0
SCHEDULE E ADJ.						(3.5)
SUBTOTAL			1,265.9			(3.5)
TEMP RATE Adj.			0.0			0.0
REVENUE ADJ			0			
INTERIM RATE INCREASE			0.0			
TOTAL REVENUE			2,831.8			2,981.1

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
SCHEDULE H - COMMERCIAL COOKING, HEATING, AIR CONDITIONING, AND REFRIGERATION SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
	MWH	¢/KWH		¢/KWH	
ENERGY CHARGE:	1,994.2	14.0975	281.1	30.3625	605.5
	KW	$/KW		$/KW	
DEMAND CHARGE:	6,265	6.00	37.6	10.00	62.7
CUSTOMER CHARGE:	BILLS	$/BILL		$/BILL	
1 PHASE	97	22.00	2.1	22.00	2.1
3 PHASE	287	28.00	8.0	28.00	8.0
SUBTOTAL	384		10.1		10.1
	MWH	¢/KWH		¢/KWH	
FUEL OIL ADJ.:	1,994.2	15.7740	314.6	0.000	0.0
UNADJUSTED REVENUES			643.4		678.3
TEMP. RATE DECREASE			0		0
SCHEDULE E ADJ.					(1.0)
INTERIM RATE INCREASE			0.0		
TOTAL REVENUES			643.4		677.3

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
SCHEDULE P - LARGE POWER SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES FOR COMBINED
SCHEDULE P AND N CUSTOMERS AT PROPOSED RATES

	BILLING UNITS	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:			2691
DEMAND CHARGE:			293.3
CUSTOMER CHARGE:			12.6
ADJUSTMENTS:			-17.9
FUEL OIL REV.			0.0
UNADJUSTED REVENUES			2,979.0
TEMP RATE DECR. (%)			
RIDER M(B) ADJ			-94.2
RIDER T ADJ			-1.7
EMPLOYEE DISCOUNT			-4
PROPOSED REVENUES SCHEDULE P AND N			2,879.1

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
SCHEDULE P - LARGE POWER SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES FOR NIGHT CONTRACT RATE
AT PROPOSED RATES

	BILLING UNITS	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	$/KWH	
ALL KWH/KW	865.9	23.0823	199.9
DEMAND CHARGE:	(KW)	$/KW	
ALL KW	5,787	3.50	20.3
	BILLS	$/BILL	
CUSTOMER CHARGE:	36	75.00	2.7
ADJUSTMENTS:			
PF			3.0
TP			0.0
DP			0.0
TS			0.0
DS			0.0
SUBTOTAL			3.0
FUEL OIL REV.	865.9	0.000	0.0
UNADJUSTED REVENUES			225.9
TEMP RATE DECR. (%)		0.000	0.0
TOTAL REVENUES NIGHT CONTRACT RATE			225.9

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
SCHEDULE P - LARGE POWER SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES FOR REGULAR P CUSTOMERS
AT PROPOSED RATES

	BILLING UNITS	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	$/KWH	
0 - 200 KWH/KW	4,467.3	32.3273	1,444.2
201 - 400 KWH/KW	2,743.7	30.2273	829.3
> 400 KWH/KW	942.5	23.0823	217.6
SUBTOTAL	8,153.5		2491.1
DEMAND CHARGE:	(KW)	$/KW	
0 - 500 KW	24,817	11.00	273.0
501 - 1500 KW	0	10.00	0.0
1501 - 5000 KW	0	10.00	0.0
> 5000 KW	0	10.00	0.0
SUBTOTAL	24,817		273.0
	BILLS	$/BILL	
CUSTOMER CHARGE:	132	75.00	9.9
ADJUSTMENTS:			
PF			(16.6)
TP			0.0
DP			(4.3)
TS			0.0
DS			0.0
SUBTOTAL			(20.9)
FUEL OIL REV.	8,153.5	0.000	0.0
UNADJUSTED REVENUES			2,753.1
TEMP RATE DECR. (%)		0.0000	0.0
RIDER M(B) ADJ			-94.2
RIDER T ADJ			-1.7
TOTAL REVENUES REGULAR SCHEDULE P			2,657.2

T

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
SCHEDULE F - PUBLIC STREET LIGHTING SERVICE
DOCKET NO. 2006-0387 TEST-YEAR 2007

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	CURRENT EFFECTIVE RATES UNIT PRICE CENTS/KWH	CURRENT EFFECTIVE RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE CENTS/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:					
0 - 150 KWH/KW	213.7	20.2685	43.3	37.9215	81.0
> 150 KWH/KW	264.8	15.8625	42.0	33.5155	88.7
SUBTOTAL	478.5		85.3		169.7
ADJUSTMENTS:					
MINIMUM BILL			0.1		0.1
SECONDARY METERING			0.0		0.0
SUBTOTAL			0.1		0.1
UNADJUSTED BASE REV.:			85.4		169.8
FUEL OIL ADJ.:	478.5	15.7740	75.5	0.0000	0.0
FIRM CAP. SURC. ADJ.:	478.5	0.0000	0.0	0.0000	0.0
EMPLOYEE DISCOUNT ADJ					-0.4
			75.5		-0.4
UNADJUSTED TOTAL REV.:			160.9		169.4
TEMP. RATE DECREASE (%)		0.0	0.0	0.0	0.0
INTERIM RATE INCREASE			0.0		
TOTAL REVENUES			160.9		169.4

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

SINGLE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$34.85	$35.82	$0.97	2.78%
200	$62.23	$64.15	$1.92	3.09%
300	$89.59	$92.47	$2.88	3.21%
400	$116.96	$121.20	$4.24	3.63%
500	$144.33	$150.34	$6.01	4.16%
600	$171.69	$179.47	$7.78	4.53%
700	$199.07	$208.60	$9.53	4.79%
800	$226.43	$237.74	$11.31	4.99%
900	$253.79	$266.88	$13.09	5.16%
1,000	$281.16	$296.01	$14.85	5.28%
1,100	$308.52	$325.15	$16.63	5.39%
1,200	$335.89	$354.29	$18.40	5.48%
1,300	$363.26	$383.97	$20.71	5.70%
1,400	$390.63	$413.64	$23.01	5.89%
1,500	$418.00	$443.32	$25.32	6.06%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

THREE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$39.35	$40.32	$0.97	2.47%
200	$66.73	$68.65	$1.92	2.88%
300	$94.09	$96.97	$2.88	3.06%
400	$121.46	$125.70	$4.24	3.49%
500	$148.83	$154.84	$6.01	4.04%
600	$176.19	$183.97	$7.78	4.42%
700	$203.56	$213.10	$9.54	4.69%
800	$230.92	$242.24	$11.32	4.90%
900	$258.30	$271.38	$13.08	5.06%
1,000	$285.66	$300.51	$14.85	5.20%
1,100	$313.02	$329.65	$16.63	5.31%
1,200	$340.40	$358.79	$18.39	5.40%
1,300	$367.76	$388.47	$20.71	5.63%
1,400	$395.13	$418.14	$23.01	5.82%
1,500	$422.50	$447.82	$25.32	5.99%

* Present Rates Effective April 15, 1999
* Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
* Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

SINGLE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$49.49	$54.80	$5.31	10.73%
200	$78.00	$84.61	$6.61	8.47%
300	$106.51	$114.41	$7.90	7.42%
400	$135.02	$144.21	$9.19	6.81%
500	$163.53	$174.02	$10.49	6.41%
600	$192.03	$203.82	$11.79	6.14%
700	$220.55	$233.63	$13.08	5.93%
800	$249.04	$263.43	$14.39	5.78%
900	$277.56	$293.23	$15.67	5.65%
1,000	$306.07	$323.04	$16.97	5.54%
2,000	$591.15	$621.07	$29.92	5.06%
3,000	$876.24	$919.11	$42.87	4.89%
4,000	$1,161.32	$1,217.15	$55.83	4.81%
5,000	$1,446.40	$1,515.19	$68.79	4.76%

'* Present Rates Effective April 15, 1999
'Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
'Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

THREE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$64.48	$69.80	$5.32	8.25%
200	$92.99	$99.61	$6.62	7.12%
300	$121.50	$129.41	$7.91	6.51%
400	$150.01	$159.21	$9.20	6.13%
500	$178.52	$189.02	$10.50	5.88%
600	$207.02	$218.82	$11.80	5.70%
700	$235.53	$248.63	$13.10	5.56%
800	$264.03	$278.43	$14.40	5.45%
900	$292.55	$308.23	$15.68	5.36%
1,000	$321.06	$338.04	$16.98	5.29%
2,000	$606.14	$636.07	$29.93	4.94%
3,000	$891.23	$934.11	$42.88	4.81%
4,000	$1,176.30	$1,232.15	$55.85	4.75%
5,000	$1,461.39	$1,530.19	$68.80	4.71%

'* Present Rates Effective April 15, 1999
* Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
* Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$837.63	$987.51	$149.88	17.89%
25	5,000	200	$1,496.67	$1,625.02	$128.35	8.58%
25	10,000	400	$2,764.05	$2,849.33	$85.28	3.09%
25	12,500	500	$3,323.73	$3,387.43	$63.69	1.92%
25	15,000	600	$3,883.43	$3,925.53	$42.10	1.08%
50	5,000	100	$1,640.30	$1,925.02	$284.72	17.36%
50	10,000	200	$2,958.35	$3,200.03	$241.68	8.17%
50	20,000	400	$5,493.11	$5,648.65	$155.54	2.83%
50	25,000	500	$6,612.51	$6,724.86	$112.35	1.70%
50	30,000	600	$7,731.89	$7,801.06	$69.17	0.89%
100	10,000	100	$3,245.63	$3,800.03	$554.40	17.08%
100	20,000	200	$5,881.72	$6,350.06	$468.34	7.96%
100	40,000	400	$10,951.25	$11,247.30	$296.05	2.70%
100	50,000	500	$13,190.03	$13,399.71	$209.68	1.59%
100	60,000	600	$15,428.81	$15,552.12	$123.31	0.80%
300	30,000	100	$9,666.93	$11,300.09	$1,633.16	16.89%
300	60,000	200	$17,575.22	$18,950.18	$1,374.96	7.82%
300	120,000	400	$32,783.80	$33,641.90	$858.10	2.62%
300	150,000	500	$39,500.14	$40,099.13	$598.99	1.52%
300	180,000	600	$46,216.48	$46,556.36	$339.88	0.74%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$852.62	$1,002.51	$149.89	17.58%
25	5,000	200	$1,511.65	$1,640.02	$128.37	8.49%
25	10,000	400	$2,779.04	$2,864.33	$85.29	3.07%
25	12,500	500	$3,338.72	$3,402.43	$63.70	1.91%
25	15,000	600	$3,898.42	$3,940.53	$42.11	1.08%
50	5,000	100	$1,655.29	$1,940.02	$284.73	17.20%
50	10,000	200	$2,973.34	$3,215.03	$241.69	8.13%
50	20,000	400	$5,508.10	$5,663.65	$155.55	2.82%
50	25,000	500	$6,627.49	$6,739.86	$112.37	1.70%
50	30,000	600	$7,746.88	$7,816.06	$69.18	0.89%
100	10,000	100	$3,260.61	$3,815.03	$554.42	17.00%
100	20,000	200	$5,896.71	$6,365.06	$468.35	7.94%
100	40,000	400	$10,966.24	$11,262.30	$296.06	2.70%
100	50,000	500	$13,205.02	$13,414.71	$209.69	1.59%
100	60,000	600	$15,443.80	$15,567.12	$123.32	0.80%
300	30,000	100	$9,681.92	$11,315.09	$1,633.17	16.87%
300	60,000	200	$17,590.21	$18,965.18	$1,374.97	7.82%
300	120,000	400	$32,798.78	$33,656.90	$858.12	2.62%
300	150,000	500	$39,515.13	$40,114.13	$599.00	1.52%
300	180,000	600	$46,231.47	$46,571.36	$339.89	0.74%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$331.07	$373.73	$42.66	12.89%
10	2,000	200	$590.19	$637.46	$47.27	8.01%
10	3,000	300	$849.32	$901.18	$51.86	6.11%
10	4,000	400	$1,108.44	$1,164.91	$56.47	5.09%
25	2,500	100	$787.20	$874.32	$87.12	11.07%
25	5,000	200	$1,435.01	$1,533.64	$98.63	6.87%
25	7,500	300	$2,082.81	$2,192.96	$110.15	5.29%
25	10,000	400	$2,730.62	$2,852.28	$121.66	4.46%
50	5,000	100	$1,547.43	$1,708.64	$161.21	10.42%
50	10,000	200	$2,843.04	$3,027.28	$184.24	6.48%
50	15,000	300	$4,138.66	$4,345.92	$207.26	5.01%
50	20,000	400	$5,434.27	$5,664.56	$230.29	4.24%
100	10,000	100	$3,067.86	$3,377.28	$309.42	10.09%
100	20,000	200	$5,659.09	$6,014.56	$355.47	6.28%
100	30,000	300	$8,250.32	$8,651.84	$401.52	4.87%
100	40,000	400	$10,841.55	$11,289.12	$447.57	4.13%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$347.06	$388.73	$41.67	12.01%
10	2,000	200	$606.18	$652.46	$46.28	7.63%
10	3,000	300	$865.31	$916.18	$50.87	5.88%
10	4,000	400	$1,124.42	$1,179.91	$55.49	4.93%
25	2,500	100	$803.19	$889.32	$86.13	10.72%
25	5,000	200	$1,451.00	$1,548.64	$97.64	6.73%
25	7,500	300	$2,098.80	$2,207.96	$109.16	5.20%
25	10,000	400	$2,746.61	$2,867.28	$120.67	4.39%
50	5,000	100	$1,563.41	$1,723.64	$160.23	10.25%
50	10,000	200	$2,859.02	$3,042.28	$183.26	6.41%
50	15,000	300	$4,154.64	$4,360.92	$206.28	4.97%
50	20,000	400	$5,450.25	$5,679.56	$229.31	4.21%
100	10,000	100	$3,083.85	$3,392.28	$308.43	10.00%
100	20,000	200	$5,675.08	$6,029.56	$354.48	6.25%
100	30,000	300	$8,266.31	$8,666.84	$400.53	4.85%
100	40,000	400	$10,857.54	$11,304.12	$446.58	4.11%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE P: LARGE POWER SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$17,740.01	$20,456.64	$2,716.63	15.31%
300	120	400	$31,782.61	$34,213.02	$2,430.41	7.65%
300	150	500	$38,290.70	$40,577.61	$2,286.91	5.97%
300	180	600	$44,798.79	$46,942.20	$2,143.41	4.78%
300	210	700	$51,306.89	$53,306.79	$1,999.90	3.90%
500	100	200	$29,416.80	$33,844.40	$4,427.60	15.05%
500	200	400	$52,821.13	$56,771.70	$3,950.57	7.48%
500	250	500	$63,667.95	$67,379.35	$3,711.40	5.83%
500	300	600	$74,514.77	$77,987.00	$3,472.23	4.66%
500	350	700	$85,361.59	$88,594.65	$3,233.06	3.79%
1,500	300	200	$87,301.13	$99,783.20	$12,482.07	14.30%
1,500	600	400	$157,514.11	$168,565.10	$11,050.99	7.02%
1,500	750	500	$190,054.58	$200,388.05	$10,333.47	5.44%
1,500	900	600	$222,595.04	$232,211.00	$9,615.96	4.32%
1,500	1,050	700	$255,135.51	$264,033.95	$8,898.44	3.49%
5,000	1,000	200	$289,896.29	$330,569.00	$40,672.71	14.03%
5,000	2,000	400	$523,939.56	$559,842.00	$35,902.44	6.85%
5,000	2,500	500	$632,407.78	$665,918.50	$33,510.72	5.30%
5,000	3,000	600	$740,875.99	$771,995.00	$31,119.01	4.20%
5,000	3,500	700	$849,344.21	$878,071.50	$28,727.29	3.38%
10,000	2,000	200	$579,317.94	$660,263.00	$80,945.06	13.97%
10,000	4,000	400	$1,047,404.48	$1,118,809.00	$71,404.52	6.82%
10,000	5,000	500	$1,264,340.92	$1,330,962.00	$66,621.08	5.27%
10,000	6,000	600	$1,481,277.35	$1,543,115.00	$61,837.65	4.17%
10,000	7,000	700	$1,698,213.79	$1,755,268.00	$57,054.21	3.36%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE F: PUBLIC STREET LIGHTING, HIGHWAY LIGHTING, AND PARK AND PLAYGROUND LIGHTING

KW	KWH	KWH/KW	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase (%)
1	150	150	$43.67	$45.89	$2.22	5.08%
1	340	340	$90.45	$95.48	$5.02	5.55%
5	750	150	$218.37	$229.47	$11.10	5.08%
5	1,700	340	$452.27	$477.39	$25.12	5.55%
10	1,500	150	$436.73	$458.93	$22.20	5.08%
10	3,400	340	$904.54	$954.78	$50.25	5.55%
25	3,750	150	$1,091.84	$1,147.33	$55.49	5.08%
25	8,500	340	$2,261.34	$2,386.95	$125.62	5.55%
50	7,500	150	$2,183.67	$2,294.66	$110.98	5.08%
50	17,000	340	$4,522.68	$4,773.91	$251.23	5.55%
100	15,000	150	$4,367.34	$4,589.31	$221.97	5.08%
100	34,000	340	$9,045.35	$9,547.82	$502.46	5.55%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.954 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = -.0769%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

SINGLE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$39.47	$40.75	$1.28	3.24%
200	$71.46	$74.00	$2.54	3.55%
300	$103.44	$107.50	$4.06	3.92%
400	$135.41	$141.26	$5.85	4.32%
500	$167.39	$175.02	$7.63	4.56%
600	$199.37	$208.77	$9.40	4.71%
700	$231.34	$242.53	$11.19	4.84%
800	$263.32	$276.68	$13.36	5.07%
900	$295.32	$311.23	$15.91	5.39%
1,000	$327.28	$345.76	$18.48	5.65%
1,100	$359.25	$380.31	$21.06	5.86%
1,200	$391.23	$414.85	$23.62	6.04%
1,300	$423.22	$449.39	$26.17	6.18%
1,400	$455.19	$483.93	$28.74	6.31%
1,500	$487.17	$518.48	$31.31	6.43%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

THREE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$43.97	$45.25	$1.28	2.91%
200	$75.96	$78.50	$2.54	3.34%
300	$107.93	$112.00	$4.07	3.77%
400	$139.91	$145.76	$5.85	4.18%
500	$171.89	$179.52	$7.63	4.44%
600	$203.87	$213.27	$9.40	4.61%
700	$235.84	$247.03	$11.19	4.74%
800	$267.82	$281.18	$13.36	4.99%
900	$299.80	$315.73	$15.93	5.31%
1,000	$331.78	$350.26	$18.48	5.57%
1,100	$363.75	$384.81	$21.06	5.79%
1,200	$395.74	$419.35	$23.61	5.97%
1,300	$427.71	$453.89	$26.18	6.12%
1,400	$459.69	$488.43	$28.74	6.25%
1,500	$491.67	$522.98	$31.31	6.37%

* Present Rates Effective April 15, 1999
* Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
* Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

SINGLE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$56.33	$65.41	$9.08	16.12%
200	$90.67	$100.81	$10.14	11.18%
300	$125.00	$136.22	$11.22	8.98%
400	$159.33	$171.62	$12.29	7.71%
500	$193.66	$207.03	$13.37	6.90%
600	$227.99	$242.44	$14.45	6.34%
700	$262.32	$277.84	$15.52	5.92%
800	$296.65	$313.25	$16.60	5.60%
900	$330.99	$348.66	$17.67	5.34%
1,000	$365.32	$384.06	$18.74	5.13%
2,000	$708.64	$738.12	$29.48	4.16%
3,000	$1,051.95	$1,092.19	$40.24	3.83%
4,000	$1,395.27	$1,446.25	$50.98	3.65%
5,000	$1,738.59	$1,800.31	$61.72	3.55%

'* Present Rates Effective April 15, 1999
* Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
* Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

THREE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$72.33	$80.41	$8.08	11.17%
200	$106.67	$115.81	$9.14	8.57%
300	$141.00	$151.22	$10.22	7.25%
400	$175.33	$186.62	$11.29	6.44%
500	$209.66	$222.03	$12.37	5.90%
600	$243.99	$257.44	$13.45	5.51%
700	$278.32	$292.84	$14.52	5.22%
800	$312.65	$328.25	$15.60	4.99%
900	$346.99	$363.66	$16.67	4.80%
1,000	$381.32	$399.06	$17.74	4.65%
2,000	$724.64	$753.12	$28.48	3.93%
3,000	$1,067.95	$1,107.19	$39.24	3.67%
4,000	$1,411.27	$1,461.25	$49.98	3.54%
5,000	$1,754.59	$1,815.31	$60.72	3.46%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$1,041.80	$1,143.30	$101.50	9.74%
25	5,000	200	$1,904.85	$2,016.61	$111.76	5.87%
25	10,000	400	$3,572.09	$3,704.36	$132.27	3.70%
25	12,500	500	$4,331.72	$4,474.16	$142.45	3.29%
25	15,000	600	$5,091.34	$5,243.97	$152.63	3.00%
50	5,000	100	$2,048.60	$2,241.61	$193.01	9.42%
50	10,000	200	$3,774.69	$3,988.21	$213.52	5.66%
50	20,000	400	$7,109.18	$7,363.72	$254.54	3.58%
50	25,000	500	$8,628.43	$8,903.33	$274.90	3.19%
50	30,000	600	$10,147.67	$10,442.93	$295.26	2.91%
100	10,000	100	$4,062.19	$4,438.21	$376.02	9.26%
100	20,000	200	$7,514.38	$7,931.42	$417.04	5.55%
100	40,000	400	$14,183.36	$14,682.44	$499.08	3.52%
100	50,000	500	$17,221.85	$17,761.65	$539.80	3.13%
100	60,000	600	$20,260.34	$20,840.86	$580.52	2.87%
300	30,000	100	$12,116.57	$13,224.63	$1,108.06	9.14%
300	60,000	200	$22,473.14	$23,704.26	$1,231.12	5.48%
300	120,000	400	$42,480.08	$43,957.32	$1,477.24	3.48%
300	150,000	500	$51,595.55	$53,194.95	$1,599.40	3.10%
300	180,000	600	$60,711.02	$62,432.58	$1,721.56	2.84%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$1,056.80	$1,158.30	$101.50	9.60%
25	5,000	200	$1,919.85	$2,031.61	$111.76	5.82%
25	10,000	400	$3,587.09	$3,719.36	$132.27	3.69%
25	12,500	500	$4,346.72	$4,489.16	$142.45	3.28%
25	15,000	600	$5,106.34	$5,258.97	$152.63	2.99%
50	5,000	100	$2,063.60	$2,256.61	$193.01	9.35%
50	10,000	200	$3,789.69	$4,003.21	$213.52	5.63%
50	20,000	400	$7,124.18	$7,378.72	$254.54	3.57%
50	25,000	500	$8,643.43	$8,918.33	$274.90	3.18%
50	30,000	600	$10,162.67	$10,457.93	$295.26	2.91%
100	10,000	100	$4,077.19	$4,453.21	$376.02	9.22%
100	20,000	200	$7,529.38	$7,946.42	$417.04	5.54%
100	40,000	400	$14,198.36	$14,697.44	$499.08	3.52%
100	50,000	500	$17,236.85	$17,776.65	$539.80	3.13%
100	60,000	600	$20,275.34	$20,855.86	$580.52	2.86%
300	30,000	100	$12,131.57	$13,239.63	$1,108.06	9.13%
300	60,000	200	$22,488.14	$23,719.26	$1,231.12	5.47%
300	120,000	400	$42,495.08	$43,972.32	$1,477.24	3.48%
300	150,000	500	$51,610.55	$53,209.95	$1,599.40	3.10%
300	180,000	600	$60,726.02	$62,447.58	$1,721.56	2.83%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$391.15	$448.36	$57.21	14.63%
10	2,000	200	$710.30	$776.72	$66.42	9.35%
10	3,000	300	$1,029.45	$1,105.07	$75.62	7.35%
10	4,000	400	$1,348.60	$1,433.43	$84.83	6.29%
25	2,500	100	$937.38	$1,060.90	$123.52	13.18%
25	5,000	200	$1,735.26	$1,881.79	$146.53	8.44%
25	7,500	300	$2,533.14	$2,702.69	$169.55	6.69%
25	10,000	400	$3,331.01	$3,523.58	$192.57	5.78%
50	5,000	100	$1,847.76	$2,081.79	$234.03	12.67%
50	10,000	200	$3,443.51	$3,723.58	$280.07	8.13%
50	15,000	300	$5,039.27	$5,365.37	$326.10	6.47%
50	20,000	400	$6,635.02	$7,007.16	$372.14	5.61%
100	10,000	100	$3,668.51	$4,123.58	$455.07	12.40%
100	20,000	200	$6,860.02	$7,407.16	$547.14	7.98%
100	30,000	300	$10,051.53	$10,690.74	$639.21	6.36%
100	40,000	400	$13,243.04	$13,974.32	$731.28	5.52%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$407.15	$463.36	$56.21	13.81%
10	2,000	200	$726.30	$791.72	$65.42	9.01%
10	3,000	300	$1,045.45	$1,120.07	$74.62	7.14%
10	4,000	400	$1,364.60	$1,448.43	$83.83	6.14%
25	2,500	100	$953.38	$1,075.90	$122.52	12.85%
25	5,000	200	$1,751.26	$1,896.79	$145.53	8.31%
25	7,500	300	$2,549.14	$2,717.69	$168.55	6.61%
25	10,000	400	$3,347.01	$3,538.58	$191.57	5.72%
50	5,000	100	$1,863.76	$2,096.79	$233.03	12.50%
50	10,000	200	$3,459.51	$3,738.58	$279.07	8.07%
50	15,000	300	$5,055.27	$5,380.37	$325.10	6.43%
50	20,000	400	$6,651.02	$7,022.16	$371.14	5.58%
100	10,000	100	$3,684.51	$4,138.58	$454.07	12.32%
100	20,000	200	$6,876.02	$7,422.16	$546.14	7.94%
100	30,000	300	$10,067.53	$10,705.74	$638.21	6.34%
100	40,000	400	$13,259.04	$13,989.32	$730.28	5.51%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE P: LARGE POWER SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$22,399.28	$26,102.90	$3,703.62	16.53%
300	120	400	$41,124.56	$44,481.80	$3,357.24	8.16%
300	150	500	$49,974.20	$53,158.25	$3,184.05	6.37%
300	180	600	$58,823.84	$61,834.70	$3,010.86	5.12%
300	210	700	$67,673.48	$70,511.15	$2,837.67	4.19%
500	100	200	$37,198.80	$43,371.50	$6,172.70	16.59%
500	200	400	$68,407.60	$74,003.00	$5,595.40	8.18%
500	250	500	$83,157.00	$88,463.75	$5,306.75	6.38%
500	300	600	$97,906.40	$102,924.50	$5,018.10	5.13%
500	350	700	$112,655.80	$117,385.25	$4,729.45	4.20%
1,500	300	200	$110,696.40	$127,714.50	$17,018.10	15.37%
1,500	600	400	$204,322.80	$219,609.00	$15,286.20	7.48%
1,500	750	500	$248,571.00	$262,991.25	$14,420.25	5.80%
1,500	900	600	$292,819.20	$306,373.50	$13,554.30	4.63%
1,500	1,050	700	$337,067.40	$349,755.75	$12,688.35	3.76%
5,000	1,000	200	$367,938.00	$422,915.00	$54,977.00	14.94%
5,000	2,000	400	$680,026.00	$729,230.00	$49,204.00	7.24%
5,000	2,500	500	$827,520.00	$873,837.50	$46,317.50	5.60%
5,000	3,000	600	$975,014.00	$1,018,445.00	$43,431.00	4.45%
5,000	3,500	700	$1,122,508.00	$1,163,052.50	$40,544.50	3.61%
10,000	2,000	200	$735,426.00	$844,630.00	$109,204.00	14.85%
10,000	4,000	400	$1,359,602.00	$1,457,260.00	$97,658.00	7.18%
10,000	5,000	500	$1,654,590.00	$1,746,475.00	$91,885.00	5.55%
10,000	6,000	600	$1,949,578.00	$2,035,690.00	$86,112.00	4.42%
10,000	7,000	700	$2,244,566.00	$2,324,905.00	$80,339.00	3.58%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE F: PUBLIC STREET LIGHTING, HIGHWAY LIGHTING, AND PARK AND PLAYGROUND LIGHTING

KW	KWH	KWH/KW	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase (%)
1	150	150	$52.42	$55.24	$2.82	5.37%
1	340	340	$110.28	$116.67	$6.38	5.79%
5	750	150	$262.10	$276.18	$14.08	5.37%
5	1,700	340	$551.42	$583.33	$31.91	5.79%
10	1,500	150	$524.20	$552.35	$28.16	5.37%
10	3,400	340	$1,102.83	$1,166.65	$63.82	5.79%
25	3,750	150	$1,310.49	$1,380.88	$70.39	5.37%
25	8,500	340	$2,757.08	$2,916.63	$159.55	5.79%
50	7,500	150	$2,620.99	$2,761.76	$140.78	5.37%
50	17,000	340	$5,514.17	$5,833.26	$319.09	5.79%
100	15,000	150	$5,241.98	$5,523.53	$281.55	5.37%
100	34,000	340	$11,028.33	$11,666.51	$638.18	5.79%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 13.9130 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

SINGLE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$40.71	$41.87	$1.16	2.85%
200	$73.93	$76.25	$2.32	3.14%
300	$107.14	$111.21	$4.07	3.80%
400	$140.36	$146.74	$6.38	4.55%
500	$173.57	$182.26	$8.69	5.01%
600	$206.77	$217.79	$11.02	5.33%
700	$239.98	$253.32	$13.34	5.56%
800	$273.19	$288.97	$15.78	5.78%
900	$306.41	$324.76	$18.35	5.99%
1,000	$339.62	$360.54	$20.92	6.16%
1,100	$372.83	$396.33	$23.50	6.30%
1,200	$406.05	$432.11	$26.06	6.42%
1,300	$439.26	$467.89	$28.63	6.52%
1,400	$472.48	$503.68	$31.20	6.60%
1,500	$505.69	$539.46	$33.77	6.68%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE

THREE PHASE

KWH	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase %
100	$45.21	$46.37	$1.16	2.57%
200	$78.43	$80.75	$2.32	2.96%
300	$111.63	$115.71	$4.08	3.65%
400	$144.85	$151.24	$6.39	4.41%
500	$178.06	$186.76	$8.70	4.89%
600	$211.27	$222.29	$11.02	5.22%
700	$244.49	$257.82	$13.33	5.45%
800	$277.70	$293.47	$15.77	5.68%
900	$310.91	$329.26	$18.35	5.90%
1,000	$344.12	$365.04	$20.92	6.08%
1,100	$377.33	$400.83	$23.50	6.23%
1,200	$410.55	$436.61	$26.06	6.35%
1,300	$443.76	$472.39	$28.63	6.45%
1,400	$476.98	$508.18	$31.20	6.54%
1,500	$510.18	$543.96	$33.78	6.62%

* Present Rates Effective April 15, 1999
* Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
* Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

SINGLE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$61.56	$64.77	$3.21	5.21%
200	$101.14	$106.55	$5.41	5.35%
300	$140.70	$148.32	$7.62	5.42%
400	$180.27	$190.09	$9.82	5.45%
500	$219.83	$231.86	$12.03	5.47%
600	$259.40	$273.64	$14.24	5.49%
700	$298.97	$315.41	$16.44	5.50%
800	$338.53	$357.18	$18.65	5.51%
900	$378.11	$398.96	$20.85	5.51%
1,000	$417.67	$440.73	$23.06	5.52%
2,000	$813.34	$858.46	$45.12	5.55%
3,000	$1,209.01	$1,276.18	$67.17	5.56%
4,000	$1,604.68	$1,693.91	$89.23	5.56%
5,000	$2,000.35	$2,111.64	$111.29	5.56%

* Present Rates Effective April 15, 1999
* Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
* Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE, NON-DEMAND

THREE PHASE

KWH	Present Rate $/Mo.	Proposed Rate $/Mo.	Increase $/Mo.	Increase %
100	$72.56	$75.77	$3.21	4.42%
200	$112.14	$117.55	$5.41	4.82%
300	$151.70	$159.32	$7.62	5.02%
400	$191.27	$201.09	$9.82	5.13%
500	$230.83	$242.86	$12.03	5.21%
600	$270.40	$284.64	$14.24	5.27%
700	$309.97	$326.41	$16.44	5.30%
800	$349.53	$368.18	$18.65	5.34%
900	$389.11	$409.96	$20.85	5.36%
1,000	$428.67	$451.73	$23.06	5.38%
2,000	$824.34	$869.46	$45.12	5.47%
3,000	$1,220.01	$1,287.18	$67.17	5.51%
4,000	$1,615.68	$1,704.91	$89.23	5.52%
5,000	$2,011.35	$2,122.64	$111.29	5.53%

'* Present Rates Effective April 15, 1999
' Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
' Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$1,033.61	$1,176.52	$142.91	13.83%
25	5,000	200	$1,918.47	$2,046.03	$127.56	6.65%
25	10,000	400	$3,395.84	$3,492.71	$96.87	2.85%
25	12,500	500	$4,088.80	$4,170.33	$81.52	1.99%
25	15,000	600	$4,781.76	$4,847.94	$66.18	1.38%
50	5,000	100	$2,037.22	$2,321.03	$283.81	13.93%
50	10,000	200	$3,806.94	$4,060.06	$253.12	6.65%
50	20,000	400	$6,761.68	$6,953.42	$191.74	2.84%
50	25,000	500	$8,147.60	$8,308.65	$161.05	1.98%
50	30,000	600	$9,533.52	$9,663.88	$130.36	1.37%
100	10,000	100	$4,044.44	$4,610.06	$565.62	13.99%
100	20,000	200	$7,583.88	$8,088.12	$504.24	6.65%
100	40,000	400	$13,493.36	$13,874.84	$381.48	2.83%
100	50,000	500	$16,265.20	$16,585.30	$320.10	1.97%
100	60,000	600	$19,037.04	$19,295.76	$258.72	1.36%
300	30,000	100	$12,073.32	$13,766.18	$1,692.86	14.02%
300	60,000	200	$22,691.64	$24,200.36	$1,508.72	6.65%
300	120,000	400	$40,420.08	$41,560.52	$1,140.44	2.82%
300	150,000	500	$48,735.60	$49,691.90	$956.30	1.96%
300	180,000	600	$57,051.12	$57,823.28	$772.16	1.35%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$1,043.61	$1,186.52	$142.91	13.69%
25	5,000	200	$1,928.47	$2,056.03	$127.56	6.61%
25	10,000	400	$3,405.84	$3,502.71	$96.87	2.84%
25	12,500	500	$4,098.80	$4,180.33	$81.52	1.99%
25	15,000	600	$4,791.76	$4,857.94	$66.18	1.38%
50	5,000	100	$2,047.22	$2,331.03	$283.81	13.86%
50	10,000	200	$3,816.94	$4,070.06	$253.12	6.63%
50	20,000	400	$6,771.68	$6,963.42	$191.74	2.83%
50	25,000	500	$8,157.60	$8,318.65	$161.05	1.97%
50	30,000	600	$9,543.52	$9,673.88	$130.36	1.37%
100	10,000	100	$4,054.44	$4,620.06	$565.62	13.95%
100	20,000	200	$7,593.88	$8,098.12	$504.24	6.64%
100	40,000	400	$13,503.36	$13,884.84	$381.48	2.83%
100	50,000	500	$16,275.20	$16,595.30	$320.10	1.97%
100	60,000	600	$19,047.04	$19,305.76	$258.72	1.36%
300	30,000	100	$12,083.32	$13,776.18	$1,692.86	14.01%
300	60,000	200	$22,701.64	$24,210.36	$1,508.72	6.65%
300	120,000	400	$40,430.08	$41,570.52	$1,140.44	2.82%
300	150,000	500	$48,745.60	$49,701.90	$956.30	1.96%
300	180,000	600	$57,061.12	$57,833.28	$772.16	1.35%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

SINGLE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$380.72	$425.63	$44.91	11.80%
10	2,000	200	$679.43	$729.25	$49.82	7.33%
10	3,000	300	$978.15	$1,032.88	$54.73	5.60%
10	4,000	400	$1,276.86	$1,336.50	$59.64	4.67%
25	2,500	100	$918.79	$1,031.06	$112.27	12.22%
25	5,000	200	$1,665.58	$1,790.13	$124.55	7.48%
25	7,500	300	$2,412.36	$2,549.19	$136.83	5.67%
25	10,000	400	$3,159.15	$3,308.25	$149.10	4.72%
50	5,000	100	$1,815.58	$2,040.13	$224.55	12.37%
50	10,000	200	$3,309.15	$3,558.25	$249.10	7.53%
50	15,000	300	$4,802.73	$5,076.38	$273.65	5.70%
50	20,000	400	$6,296.30	$6,594.50	$298.20	4.74%
100	10,000	100	$3,609.15	$4,058.25	$449.10	12.44%
100	20,000	200	$6,596.30	$7,094.50	$498.20	7.55%
100	30,000	300	$9,583.45	$10,130.75	$547.30	5.71%
100	40,000	400	$12,570.60	$13,167.00	$596.40	4.74%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, A/C, & REFRIGERATION SERVICES

THREE PHASE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
10	1,000	100	$386.72	$431.63	$44.91	11.61%
10	2,000	200	$685.43	$735.25	$49.82	7.27%
10	3,000	300	$984.15	$1,038.88	$54.73	5.56%
10	4,000	400	$1,282.86	$1,342.50	$59.64	4.65%
25	2,500	100	$924.79	$1,037.06	$112.27	12.14%
25	5,000	200	$1,671.58	$1,796.13	$124.55	7.45%
25	7,500	300	$2,418.36	$2,555.19	$136.83	5.66%
25	10,000	400	$3,165.15	$3,314.25	$149.10	4.71%
50	5,000	100	$1,821.58	$2,046.13	$224.55	12.33%
50	10,000	200	$3,315.15	$3,564.25	$249.10	7.51%
50	15,000	300	$4,808.73	$5,082.38	$273.65	5.69%
50	20,000	400	$6,302.30	$6,600.50	$298.20	4.73%
100	10,000	100	$3,615.15	$4,064.25	$449.10	12.42%
100	20,000	200	$6,602.30	$7,100.50	$498.20	7.55%
100	30,000	300	$9,589.45	$10,136.75	$547.30	5.71%
100	40,000	400	$12,576.60	$13,173.00	$596.40	4.74%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE P: LARGE POWER SERVICE

KW	MWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
300	60	200	$20,865.18	$22,771.38	$1,906.20	9.14%
300	120	400	$38,895.36	$40,907.76	$2,012.40	5.17%
300	150	500	$45,766.95	$47,832.45	$2,065.50	4.51%
300	180	600	$52,638.54	$54,757.14	$2,118.60	4.02%
300	210	700	$59,510.13	$61,681.83	$2,171.70	3.65%
500	100	200	$34,725.30	$37,902.30	$3,177.00	9.15%
500	200	400	$64,775.60	$68,129.60	$3,354.00	5.18%
500	250	500	$76,228.25	$79,670.75	$3,442.50	4.52%
500	300	600	$87,680.90	$91,211.90	$3,531.00	4.03%
500	350	700	$99,133.55	$102,753.05	$3,619.50	3.65%
1,500	300	200	$103,875.90	$112,556.90	$8,681.00	8.36%
1,500	600	400	$194,026.80	$203,238.80	$9,212.00	4.75%
1,500	750	500	$228,384.75	$237,862.25	$9,477.50	4.15%
1,500	900	600	$262,742.70	$272,485.70	$9,743.00	3.71%
1,500	1,050	700	$297,100.65	$307,109.15	$10,008.50	3.37%
5,000	1,000	200	$345,903.00	$373,848.00	$27,945.00	8.08%
5,000	2,000	400	$646,406.00	$676,121.00	$29,715.00	4.60%
5,000	2,500	500	$760,932.50	$791,532.50	$30,600.00	4.02%
5,000	3,000	600	$875,459.00	$906,944.00	$31,485.00	3.60%
5,000	3,500	700	$989,985.50	$1,022,355.50	$32,370.00	3.27%
10,000	2,000	200	$691,656.00	$747,121.00	$55,465.00	8.02%
10,000	4,000	400	$1,292,662.00	$1,351,667.00	$59,005.00	4.56%
10,000	5,000	500	$1,521,715.00	$1,582,490.00	$60,775.00	3.99%
10,000	6,000	600	$1,750,768.00	$1,813,313.00	$62,545.00	3.57%
10,000	7,000	700	$1,979,821.00	$2,044,136.00	$64,315.00	3.25%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE N: CONTRACT OFF-PEAK AND INTERRUPTIBLE SERVICE

KW	KWH	KWH/KW	Present $/Mo.	Proposed $/Mo.	Increase $/Mo.	Increase %
25	2,500	100	$690.13	$739.56	$49.43	7.16%
25	5,000	200	$1,262.75	$1,316.62	$53.87	4.27%
25	10,000	400	$2,408.00	$2,470.73	$62.73	2.61%
25	12,500	500	$2,980.63	$3,047.79	$67.16	2.25%
25	15,000	600	$3,553.25	$3,624.85	$71.60	2.01%
50	5,000	100	$1,305.25	$1,404.12	$98.87	7.57%
50	10,000	200	$2,450.50	$2,558.23	$107.73	4.40%
50	20,000	400	$4,741.00	$4,866.46	$125.46	2.65%
50	25,000	500	$5,886.25	$6,020.58	$134.33	2.28%
50	30,000	600	$7,031.50	$7,174.69	$143.19	2.04%
100	10,000	100	$2,535.50	$2,733.23	$197.73	7.80%
100	20,000	200	$4,826.00	$5,041.46	$215.46	4.46%
100	40,000	400	$9,407.00	$9,657.92	$250.92	2.67%
100	50,000	500	$11,697.50	$11,966.15	$268.65	2.30%
100	60,000	600	$13,988.00	$14,274.38	$286.38	2.05%
300	30,000	100	$7,456.50	$8,049.69	$593.19	7.96%
300	60,000	200	$14,328.00	$14,974.38	$646.38	4.51%
300	120,000	400	$28,071.00	$28,823.76	$752.76	2.68%
300	150,000	500	$34,942.50	$35,748.45	$805.95	2.31%
300	180,000	600	$41,814.00	$42,673.14	$859.14	2.05%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
TEST YEAR: 2007, DOCKET NO: 2006-0387
BILL COMPARISONS UNDER
PRESENT RATES & PROPOSED RATES
SCHEDULE F: PUBLIC STREET LIGHTING, HIGHWAY LIGHTING, AND PARK AND PLAYGROUND LIGHTING

KW	KWH	KWH/KW	Present Rates $/Mo.	Proposed Rates $/Mo.	Increase $/Mo.	Increase (%)
1	150	150	$54.06	$56.88	$2.82	5.21%
1	340	340	$114.17	$120.56	$6.39	5.60%
5	750	150	$270.32	$284.41	$14.09	5.21%
5	1,700	340	$570.87	$602.81	$31.94	5.60%
10	1,500	150	$540.64	$568.82	$28.18	5.21%
10	3,400	340	$1,141.73	$1,205.62	$63.89	5.60%
25	3,750	150	$1,351.59	$1,422.06	$70.46	5.21%
25	8,500	340	$2,854.33	$3,014.04	$159.72	5.60%
50	7,500	150	$2,703.19	$2,844.11	$140.93	5.21%
50	17,000	340	$5,708.66	$6,028.09	$319.43	5.60%
100	15,000	150	$5,406.38	$5,688.23	$281.85	5.21%
100	34,000	340	$11,417.31	$12,056.17	$638.86	5.60%

* Present Rates Effective April 15, 1999
Test -year 2007 FOA:
@present rates = 15.7740 ¢/kWh
@ proposed rates = 0.000 ¢/kWh
Test - year 2007 Firm Capacity Surcharge:
@present rates = 0.0%
@proposed rates = 0.000%

MECO T-19
DOCKET NO. 2006-0387

TESTIMONY OF
ALAN K.C. HEE

MANAGER
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Energy Cost Adjustment Clause
Energy Policy Act of 2005

INTRODUCTION

Q. Please state your name and business address.

A. My name is Alan K.C. Hee and my business address is 220 South King Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of Hawaiian Electric Company, Inc.'s Energy Services Department ("ESD").

Q. What is your educational background and professional experience?

A. My experience and educational background are listed in HECO-1900.

Q. What is your area of responsibility in this testimony?

A. I will address:

- The Maui Electric Company, Limited ("MECO" or "Company") Energy Cost Adjustment Clause ("ECAC").
- Whether MECO's ECAC complies with the requirements of Act 162.
- Whether the commission should adopt, modify, or decline to adopt in whole or in part, the standards for time-based metering and communications articulated in section 111(d)(14) of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), as amended by the Energy Policy Act of 2005 ("EPACT") (16 U.S.C. § 2621(d)(14)).

ENERGY COST ADJUSTMENT CLAUSE

Q What are the test year Energy Cost Adjustment ("ECA") factors at present and proposed rates for each of MECO's divisions?

A. The test year ECA factors at present rates and proposed rates, as shown on MECO-1901 are as follows:

1) For the Maui Division, the ECA factor is 13.954 ¢/kWh at present rates, and 0.000 ¢/kWh at proposed rates;

2) For the Lanai Division, the ECA factor is 13.913 ¢/kWh at present rates, and 0.000 ¢/kWh at proposed rates;

3) For the Molokai Division, the ECA factor is 15.774 ¢/kWh at present rates, and 0.000 ¢/kWh at proposed rates.

Q. What is the Energy Cost Adjustment Clause ("ECAC")?

A. The ECAC is an automatic adjustment provision in the utility's rate schedules that allows the utility to automatically increase or decrease charges to reflect the change in the Company's energy costs of fuel and purchased energy above or below the levels included in the base charges without a rate proceeding. The Company's current base fuel energy charges and fixed efficiency factor embedded in the base charges, shown in MECO-1902, were established in MECO'S 1999 Test Year rate case, Docket No. 97-0346.

Q. What is the purpose of the ECAC?

A. The purpose of the ECAC is (1) to address price changes in the Company's cost of fuel and purchased energy and (2) to accommodate changes to the actual mix of generation, DG (distributed generation) and purchased energy resources, without the need for a rate case.

Q. How does the ECAC work?

A. A rate case proceeding determines the base electricity rates in which are embedded test year levels of fuel prices, payment rates for purchased energy and a test year resource mix. The ECAC mechanism, expressed in cents per kilowatt-hour, allows the Company to recover from, or return to, customers costs due to subsequent changes in (1) fuel and purchased energy costs, (2) the resource mix

between utility-owned generation, utility-DG and purchased energy, (3) the resource mix among the utility plants, and (4) the resource mix among purchased energy producers. Prior rate case proceedings established a fixed efficiency factor, or sales heat rate, for the utility central station generation to encourage efficient operation of the system units. An ECA Factor, which sets the rate adjustment that reflects these changes for the coming month, is filed with the Commission monthly.

Q. How much revenue has been collected/returned through MECO's ECAC on a historical basis?

A. Since 1984 annual revenues have varied between a return to customers of $24,000,000 in 1988, to a collection from customers of $161,000,000 in 2006, as shown in MECO-1903. The amount of revenue recovered or returned through the ECAC is a function of the actual costs and resource mix percentages for generated and purchased energy, the costs embedded in base rates and the fixed efficiency factor of MECO's generation units embedded in base charges.

Q. What costs are currently passed through the ECAC?

A. The Company's fuel oil and fuel related costs in the Generation Component and purchased energy cost in the Purchased Energy Component pass through the ECAC. In the generation component, the industrial and diesel fuel oil costs, discussed by Mr. Sakuda (MECO-T-4) passes through the ECAC. Fuel related costs that pass through the ECAC at present rates are the inspection cost (referred to as Petrospect expense) and ocean cargo insurance cost. In the purchased energy component, only payments for purchased energy are passed through the ECAC.

Q. Are costs being passed through the ECAC at present rates the same as the costs being passed through the ECAC at proposed rates?

A. No. At proposed rates, the Company is proposing to pass through the ECAC the additive costs and Hana's DG fuel costs that are discussed in Mr. Sakuda's testimony (HECO-T-4). These costs are not currently being passed through the ECAC. In the near future, MECO will request Commission approval of a fuel supply contract with Maui Oil Company, Inc. for Hana's DG fuel, and to include the fuel contract costs in MECO's ECAC.

Q. Why does the Company need the ECAC?

A. The Company needs the ECAC because fuel costs are a large portion of its expenses and because fuel price levels are largely beyond the Company's control.

In the test year, fuel and purchased energy expenses make up approximately 8182% of total O&M expenses. This makes the Company's financial condition very sensitive to changes in fuel prices. The ECAC benefits the Company and its shareholders by:

- Limiting the swings in cash flow and earnings,
- Reducing the cost of capital,
- Improving the Company's ability to earn a fair return on investor capital, and;
- Providing more timely recovery of fuel and purchased energy costs.

Q. How does the ECAC benefit customers?

A. The ECAC benefits customers by:

- Reducing the Company's financial risk and lowering the cost of capital. The resulting savings are passed on to our customers through lower base rates in rate proceedings such as this one.

- Passing through to customers, the savings incurred when fuel prices fall below the prices embedded in base rates, to the same extent that they will incur additional costs when fuel prices are above the embedded fuel prices.

Q. What other benefits does the ECAC have?

A. Since the ECAC is an automatic clause it allows the Commission time to concentrate on other key, substantive strategic issues.

Q. How is the ECA factor computed at present rates?

A. The calculation of the ECA factor at present rates has two base composite cost components, the generation component and the purchased energy component. The ECA factor is equal to the difference between test year energy costs and base composite costs of the generation and purchased energy component that were established in the last rate case. The fixed efficiency factor for the central station generation is also established in the last rate case. Computation of the ECA factor at present rates is similar to the monthly factor computation filed with the Commission, as shown in MECO-1904.

<u>Maui Division</u>

Q. What are the Maui Division ECA factors at present and proposed rates?

A. The Maui Division ECA factors at present and proposed rates are 13.954 ¢/kwh and 0.000 ¢/kwh, respectively, as shown in MECO-1901.

Q. Why is there a difference between the composite cost of generation at present rates and proposed rates for Maui Division, as shown on MECO-1905?

A. At proposed rates, the Company is proposing to pass through the ECAC, the fuel additive costs for the Kahului units. In addition, costs of Hana DG fuel are currently not being passed through the ECAC at present rates. In effect, the current ECAC treats Hana DG fuel as having no cost. As noted below, at

proposed rates the DG fuel and trucking costs will be included in the ECAC under a new DG energy component. The removal of the Hana DG fuel at zero cost from the composite cost of generation at present rates also leads to an increase in the test year estimate of the composite cost of generation at proposed rates.

Q. How is the ECA factor computed at proposed rates?

A. The proposed calculation of the ECA factor consists of three base composite cost components, the central station generation component, the DG energy component and the purchased energy component, as shown in MECO-1906.

Q. Why are the ECA factors different at present and proposed rates?

A. There are two reasons for the difference. First, the base central station fuel cost, base DG energy cost and base purchased energy cost at proposed rates have been changed to reflect the test year composite costs for central station fuel, DG energy and purchased energy. Second, the fixed fuel efficiency factor (sales heat rate) used to calculate the base central station generation component cost at proposed rates has been revised to reflect the test year fuel efficiency. The calculation of the ECA factor at present rates uses the base composite costs for fuel and purchased energy and the fuel efficiency factor established in the MECO's 1999 Test Year rate case, Docket No. 97-0346.

Q. Why is the Company proposing to include the DG component?

A. The Company is proposing to include the DG component in its proposed rates to allow the Company to recover the fuel, transportation costs, and related revenue taxes, incurred under the utility's DG agreements to the extent that the costs are not recovered in the Company's base charges. The DG component is the same DG component proposed in Docket 2006-0386, HECO's 2007 Test Year Rate Case.

Q. If the Company's DG installations are utility-owned generators why are they treated differently from the Company's other utility-owned generators?

A. DG units are generally more efficient than other Company-owned generating units and would tend to improve system efficiency and lower the system heat rate. As more utility DG units are installed, the system heat rate will continue to improve. Separating the Company's DG generation from the Company's other utility-owned generation in the ECA factor calculation will allow the benefits of DG units' improved efficiency to pass through the ECAC to MECO's customers. If the utility-owned DG generation were included with the Company's other utility owned generation, the resulting efficiency factor would be fixed in base rates. However, as the number of DG units increase over time, the actual system heat rate would improve. With the DG generation included in the fixed efficiency factor, the heat rate improvements would not be passed through to the customers.

Q. How does the DG component allow ratepayers to benefit from the improved efficiency resulting from the installation of utility-owned DG?

A. The DG component would recover DG fuel and transportation costs at actual expense levels and would not be subject to the fixed efficiency factor. Thus, to the extent that the DG unit heat rates are better than the fixed efficiency factor, the actual DG efficiency will pass through the ECAC.

Q. Why is the Company proposing a weighted efficiency factor in its central station generation component?

A. The Company is proposing to include a weighted efficiency factor in its proposed ECAC calculations, in the same manner as was introduced in Docket No. 05-0315, Hawaii Electric Light Company, Inc. (HELCO) 2006 Test Year Rate Case and also in Docket No. 2006-0386, HECO's 2007 Test Year Rate Case. The

dockets are on-going before the Commission. The proposed weighted efficiency factor addresses the diversity of fuel burned in MECO's central station generating units and is used in the calculation of the weighted composite central station and other generation cost.

Q. How is the weighted efficiency factor determined?

A. The fixed efficiency factors for industrial and diesel generating units, as shown in MECO-1907, are determined from the production simulation as discussed in Mr. Sakuda's testimony. The efficiency factor of each generating unit type is weighted by the mWh contribution of each type to the total central station mWh generation. At HELCO, a third efficiency factor was derived for company-owned renewable generating units (wind and hydro at HELCO). While MECO does not own any renewable generating units, the third "other" efficiency factor has been derived and included in MECO's proposed ECA clause for consistency.

Q. How will the weighted efficiency factor work in the monthly ECAC calculations?

A. The actual mWh contribution of each type to the total central station will be incorporated in determining the weighted efficiency factor. Thus, the weighted efficiency factor is a function of the actual mix percentages of central station fuel type generation and is not fixed. The weighted central station composite cost is determined by multiplying the composite cost of generation by the weighted efficiency factor. The efficiency factor used to calculate the weighted base central station and other generation cost, however, remains fixed. An illustration of the proposed weighted composite generation cost in the ECAC calculations mechanism is shown on MECO-1908.

<u>Lanai Division</u>

Q. What are the Lanai Division ECA factors at present and proposed rates?

A. The Lanai Division ECA factors at present and proposed rates are 13.913 ¢/kwh and 0.000 ¢/kwh, respectively, as shown in MECO-1901. Computation of the ECA factors at present rates and proposed rates are shown in MECO-1909 and 1910, respectively.

Q. When the CHP unit at Manele Bay is placed in-service (assuming it is approved by the Commission) will the associated fuel expenses be recovered through Lanai's DG component?

A. Yes. In Docket No. 2006-0186, MECO requested approval to include the fuel expenses associated with the Manele Bay generating unit in the ECAC (to the extent that such costs are not included in MECO's base rates), which does not have a DG component. Should MECO's ECAC for Lanai Division be approved in this proceeding, the fuel expenses associated with the Manele Bay unit will be included in the proposed DG component.

<u>Molokai Division</u>

Q. What are the Molokai Division ECA factors at present and proposed rates?

A. The Molokai Division ECA factors at present and proposed rates are 15.774 ¢/kwh and 0.000 ¢/kwh, respectively, as shown in MECO-1901. Computation of the ECA factors at present rates and proposed rates are shown in MECO-1911 and 1912, respectively.

Q. Does MECO have any DG units on Molokai or is MECO planning to install any DG units on Molokai, during the test year?

A. No.

Q. What is the reason that MECO is proposing to include a DG component in Molokai's ECAC?

A. MECO is proposing to include a DG component for two reasons; 1) to be consistent with the HELCO and HECO ECAC proposals made in Docket Nos. 05-0315 and 2006-0386, respectively, and with the other two division of MECO, and 2) to facilitate the addition of utility-owned DG on Molokai, should it occur in the future.

Avoided Energy Cost Rates and Schedule Q

Q. How are the avoided energy cost rates and Schedule Q rates for Qualifying Facilities less than 100 kW determined?

A. The Company currently uses the proxy method in its calculations of the avoided cost rates and Schedule Q rates. The calculations are a function of the composite fuel costs and certain proxy heat rates, as shown in MECO-WP-1906, pages 8 and 9. The composite fuel costs include the fuel, transportation costs and fuel related costs for all Company-owned generation.

Pending before the Commission is Docket No. 7310, in which the parties to the proceeding are in agreement that the proxy method should be replaced by the QF In/QF Out method for the Maui Division. However, the proxy method for the Lanai and Molokai Divisions will continue to be used. Upon the issuance of a Commission decision and order in that proceeding, MECO will comply with the Commission's ruling included in the decision and order.

Q. Are the calculations of avoided energy cost and Schedule Q modified due to the inclusion of the DG component in the ECAC?

A. Yes. The avoided energy cost rates and Schedule Q payment rate incorporate the DG component in the composite fuel cost.

Q. What modifications were made to the calculations of avoided energy cost and Schedule Q?

A. The composite fuel cost of total generation is a weighted composite cost, based on the central station energy component and the Company-owned DG energy component, as shown in MECO-WP-1906, page 7.

Q. Avoided costs for on-peak and off-peak and schedule Q rates are used to determine the energy expense for as-available IPPs. Why are the test year estimates of avoided cost and schedule Q rates the same for both present rates and proposed rates?

A. The avoided costs and schedule Q rates at proposed rates were used in the present rates calculations in order to keep fuel prices consistent in the determination of the ECA factors at present rates and proposed rates.

Act 162

Q. On June 2, 2006, the Governor of Hawaii signed into law Act 162, which amends Section 269-16 of the Hawaii Revised Statutes. How does Act 162 affect the ECAC?

A. Act 162, in part, states the following:

> Any automatic fuel rate adjustment clause requested by a public utility in an application filed with the commission shall be designed, as determined in the commission's discretion, to:
> (1) Fairly share the risk of fuel cost changes between the public utility and its customers;
> (2) Provide the public utility with sufficient incentive to reasonably manage or lower it fuel costs and encourage greater use of renewable energy;
> (3) Allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts;
> (4) Preserve, to the extent reasonably possible, the public utility's financial integrity; and

(5) Minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs.

Q. How has the Company approached the issue of whether MECO's ECAC complies with Act 162?

A. The Company has selected a highly qualified consultant, National Economic Research Associates, Inc. ("NERA"), to provide assistance in evaluating the extent to which HECO, HELCO and MECO ("the Companies") currently comply with the requirements of Act 162. The consultant's final report was received on December 28, 2006 and was submitted to the Commission on December 29, 2006 in Docket No. 2006-0386, HECO's Test Year 2007 rate case.

Further, in HELCO ST-23, Docket No. 05-0315 (HELCO's 2006 Test Year rate case), Dr. Jeff Makholm, Senior Vice President of NERA, explains the role of fuel adjustment clauses in utility ratemaking in the United States and analyzes whether the Companies' ECAC complies with Act 162. In HELCO ST-24 of the same docket, Mr. Eugene Meehan, also a Senior Vice President at NERA, discusses the possibility of the Companies engaging in fuel price hedging and assesses the potential impact of fuel price hedging on the Companies, their customers, and the regulatory ratemaking process. The consultant's final report filed on December 29, 2006 in Docket No. 2006-0386, and the testimonies of Dr. Makholm (HELCO ST-23) and Mr. Meehan (HELCO ST-24) filed in Docket No. 05-0315 are incorporated herein by reference.

In MECO T-17, Ms. Tayne Sekimura explains the impact that potential changes to the ECAC could have on investors.

Q. How does MECO's ECAC compare with fuel adjustment clauses ("FACs") in other states?

A. According to Dr. Makholm, "FACs are prevalent throughout the U.S. Of the 32 traditionally regulated states, only Utah and Vermont lack FACs. Furthermore, the "ECAC compares well to the FACs that are used in traditionally-regulated jurisdictions in the U.S. Nearly all traditionally regulated and most restructured states have some similar mechanism for power cost recovery with complete fuel cost recovery." "Like the ECAC, most (about 22) of the 30 traditionally regulated states with fuel clauses have some form of true-up mechanism to reconcile actual and forecasted cost recovery."

Q. Act 162 requires the design of the ECAC to consider a number of factors including fuel price risk sharing between the Company and its ratepayers. What is MECO's position on the appropriate level of fuel price risk sharing in the ECAC?

A. It is MECO's position that the current level of ECAC fuel price risk sharing is appropriate, and that no change is necessary to the current ECAC risk sharing approach.

The ECAC does not necessarily pass 100% of any change in fuel expenses to ratepayers. MECO's ability to recover its fuel expenses is subject to an efficiency factor, which measures how efficiently MECO converts fuel energy into electrical energy. If MECO cannot meet the efficiency factor embedded in the ECAC, it recovers only a portion of its fuel expenses. Thus, MECO is already at risk for the non-recovery of some portion of fuel expense and this risk profile is inherent in the currently employed ECAC mechanism.

The risk associated with meeting the efficiency factor is one that MECO can address through the overhaul and maintenance of its generating units and unit commitment schedule among others. Thus, it is reasonable for the Commission to

hold the Company responsible for not meeting the efficiency standard and for its fuel expenses to be subject to the risk of non-recovery as a result.

However, fuel prices are subject to market forces and geopolitical events that MECO cannot control. A risk sharing mechanism which penalizes the Company because prices increase above an expected base price, even one which provides a symmetric positive incentive when prices are below the base, holds the Company financially responsible for events beyond its control. Such a risk sharing mechanism would place the Company in an untenable financial position, for which it is not compensated.

Therefore, MECO maintains that the current level of ECAC risk sharing is appropriate, and that no change is necessary to the current ECAC risk sharing approach.

Q. Did NERA consider the use of fuel price hedging as a method to mitigate the risk of sudden or frequent fuel cost changes?

A. Yes, it did. In HELCO ST-24, Mr. Meehan concluded that:

1) Even if rate smoothing is a desired goal, there may be more effective means of meeting the goal.

2) While [MECO] could partially hedge against oil price risk for periods of just over a year into the future, there would be considerable costs to doing so.

3) Were [MECO] to hedge, it would at best be able to partially hedge as there are considerable differences in price fluctuations between the hedges [MECO] could readily purchase and the cost of the oil it burns.

4) Were [MECO] to hedge, it would encounter periods during which it experienced gains on its hedges and other periods during which it experienced losses.

5) Hedging of oil by [MECO] would not be expected to reduce fuel and purchased power costs and, in fact, would be expected to increase the level of such costs.

6) It would not be reasonable for [MECO] to take the position of a principal and speculate in the oil market with shareholders assuming the risk of oil derivative gains and losses.

Q. Does MECO have plans to explore ways to mitigate the impact of fuel price volatility on customers?

A. Dr. Makholm in Docket No. 05-0315 has identified two rate smoothing alternatives, budget billing and fixed rate billing. MECO will explore these two concept alternatives to determine if they are appropriate for implementation at MECO.

ENERGY POLICY ACT OF 2005

Q. How does EPACT 2005 define "time-based rate schedule"?

A. As defined by the EPACT 2005, a time-based rate schedule is a "schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's cost of generating and purchasing electricity at the wholesale level." The federal standard lists three types of time-based rate schedules that may be offered, among others:

1) Time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-

established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall.

2) Critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption.

3) Real-time pricing whereby electricity prices are set for a specific time period on an advance or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly.

The fourth definition in the federal standards is credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations. This is more of a load management concept, than a time-based rate schedule.

Q. What does EPACT 2005 require with respect to time-based rates?

A. EPACT 2005 requires that each State regulatory authority conduct an investigation and issue a decision as to whether it is appropriate to implement the following standards:

1) Each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

2) Each electric utility shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate.

Q. What are the intended benefits of time-based rates?

A. Time-based rates, if designed properly, are intended to provide price signals to consumers on the time-based rate schedule, so they can make decisions on when or whether to use electricity. With this pricing information, the consumer can then choose between consuming electricity now or deferring consumption to another, less costly, time period. Intended benefits of time-based rates may include reduced peak load demand, reduced total demand, increased reliability, more efficient use of current capacity, and lower consumer bills. For example, resulting reductions in peak demand may permit more expensive generators to run less often, and may also reduce the need for the addition of peaking capacity. Deferring consumption also can improve reliability by reducing the load on existing generators and purchased power providers. These benefits are only realized, however, if consumers significantly reduce their demand in response to price signals. Also, analysis and/or market tests may be used to determine if these benefits can be attained in a more cost effective manner using alternative means.

Q. If the rate design proposals in this proceeding are approved by the Commission would MECO comply with the first standard?

A. Generally, yes. MECO's rate proposals in this proceeding will provide a time-of-use rate schedule option for each of its customer classes (except for Schedule F - Street Light Service customers, which do not have significant flexibility to shift load). Should all of the proposed voluntary time-based rates be approved, the portfolio of time-of-use rates will include:

	Time-Based Rate	Applicable Customer Class
1)	TOU-R, Residential Time-of-Use Service	Sch. R & E
2)	TOU-G, Small Commercial Time-of-Use Service	Sch. G, H
3)	TOU-J, Commercial Time-of-Use Service	Sch. J, K
4)	TOU-P, Large Power Time-of-Use Service	Sch. P
5)	Rider M, Off-Peak and Curtailable Service	Sch. J, P
6)	Rider T, Time-of-Day Rider	Sch. J, P

As Mr. Peter Young also states in MECO T-18, MECO "proposes to manage participation in these optional rates while collecting data for future time-of-use rate design offerings by setting a limit on the number of meters that can participate in each optional rate schedule. The meter limit facilitates effective implementation of these rate options since the current billing system cannot bill time-of-use rates automatically, should the Company's new Customer Information System ("CIS") not be in place by the time these proposed rates are approved. In addition, the Company has not estimated any revenue adjustment for customer participation in these time-of-use rate options, so the meter limit helps to mitigate any negative revenue impact that the Company might experience in implementing these rate options."

In addition, in order to enable the customer to manage his energy use, each customer on a TOU rate schedule will be provided with a time-of-use meter so that the appropriate period pricing can be accurately billed on a monthly basis.

Q. Is MECO investigating new metering technology?

A. Yes. Even though MECO proposes to implement time-of-use rate options with existing metering technology, its affiliate company, HECO, continues to proactively investigate Advanced Metering Infrastructure ("AMI") solutions. For

example, in October 2006, HECO agreed to partner with Sensus Metering Systems to field test the FlexNet system, which is a full two-way fixed network AMI system that delivers interval meter data. The FlexNet system can facilitate time-of-use pricing options, as well as transmit meter status information. This pilot program will include approximately 500 Sensus "smart" meters in the Honolulu area. MECO may benefit from the work being pursued by HECO, should AMI prove to be appropriate for metering purposes.

Q. Does MECO currently comply with the second standard?

A. Yes. For each participant in its existing or proposed time-of-use rate options, MECO provides or will provide a time-of-use meter to record and properly reflect period pricing.

Q. Does MECO offer other rate options that take into account the time at which energy is used by the customer?

A. Yes. Mr. Peter Young explains some of these rate options in MECO T-18. For example, Rider M is an optional off-peak and curtailable service applicable to Schedule J customers with loads greater than 100 kW, and to customers served under Schedule P, with loads greater than 300 kW. Rider M provides load management incentives to customers by modifying the determination of the billing demand under Schedule J or Schedule P. It offers two load management service options: Option A – Off-Peak Service, and Option B – Curtailable Service.

Q. Does MECO plan to offer any of the other types of time-based options?

A. Yes. MECO has included a commercial & industrial load management program and a residential load management program in its IRP-3 final preferred plan. The commercial & industrial load management program would provide credits for customers with large loads who enter into pre-established peak load reduction

agreements. The residential load management program would provide credits to residential customers who agree to allow MECO to control their electric water heaters or air conditioners. Under the proposed load management programs, MECO would pay incentives to customers (which can be a credit to the customers' bills) who install a load control receiver on selected electrical loads. In the execution of its five-year IRP Action Plan to be filed with the Commission MECO will re-evaluate the cost-effectiveness of the load management programs before deciding on the size of any such programs and the scheduling of their implementation.

Q. What is the status of critical peak pricing and real-time pricing, the other two examples of time-based rates included in EPACT 2005?

A. Each type of time-based rate is different and may not work the same for all consumer sectors. Most of the benefits of time-based rates will be realized only if consumers respond to price signals and can and do change their consumption patterns. As a result, it is important to understand what types of consumers are present in the market. If load is made up of consumers that are willing and able to adjust their load, then there is more potential than with unresponsive load. This means that sector composition (percent residential vs. percent commercial vs. percent industrial, etc), the willingness of each sector to accept price risk, and the level of risk they are willing to accept, will determine the price responsiveness overall. Residential consumers may have a preference for lower risk. Large commercial and industrial consumers may be more responsive to dynamic prices. Large industrial consumers, which are not generally present on the MECO system, may have more options to curtail load and may also have the benefit of on-site generation. Thus, time-based rates may only be appropriate for certain consumer

sectors or utilities in some locations and the end decision may be that time-based rates are appropriate for some sectors or utilities but not for others.

MECO understands that critical peak pricing and real-time pricing rate levels on the mainland are based, in part, on market prices for electricity. However, because MECO lacks access to a wholesale market (i.e., MECO operates stand alone systems on the islands of Maui, Lanai, and Molokai), a pricing signal to drive critical peak pricing and real-time pricing is not available to the Company. Thus, it is unclear at what levels MECO's critical peak pricing or real-time pricing rates would be set. In addition, since MECO has proposed time-of-use rates for its customer classes in this rate proceeding, it would be prudent to evaluate its customers' response to those rates before moving to rates that are more complicated for customers to understand. Therefore, the Company is not proposing critical peak and real-time pricing at this time.

Q. What is MECO's recommendation regarding the time-based metering and communications standards included in the Energy Policy Act of 2005?

A. MECO recommends that the Commission's adoption of the standards articulated the Energy Policy Act of 2005 is not necessary because:

1) The Company will comply with the standard regarding the offer of time-based rates once the proposed rate design is approved.

2) MECO's affiliate company, HECO, is already proactively investigating advanced metering and telecommunications infrastructure ("AMI") solutions that will enhance the ability of the consumer to manage his energy use and cost. These solutions may prove to be beneficial to MECO as well.

Q. Since MECO generally is in compliance with the standard, does that mean that the Commission should adopt the standard?

A. No. First, as stated above, adoption of the standard is unnecessary. In addition, adoption of the standard could have unintended consequences. For example, the standard could be construed to require that street light customers be offered a time-of-use option, or that there be no initial limit on the number of meters that can initially participate.

In general, one size fits all federal standards are not the optimal method to achieve objectives such as equitable rates for electricity consumers. The purpose underlying PURPA can be met without adopting the time-based metering and communications standards. The stated purposes of the PURPA Title I standards, as enunciated in 1978, are to encourage (1) conservation of energy supplied by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates for electric consumers. The Conference Committee Report that accompanied the passage of PURPA in 1978 explained further that the first purpose of the Title was to foster conservation by end-users of electricity. The second purpose was directed at utilities and their use of energy and their facilities, including capital resources, and intended this to include "conserving scarce energy resources by techniques of rate reform which substitute the use of more plentiful resources produced in the United States in lieu of less plentiful resources, especially those imported into this Country." Joint Explanatory Statement of the Committee of Conference, Conference Committee Report accompanying Public Law 95-61 7 (PURPA), 1978, p. 69. Nothing further was added to the third purpose beyond what was said in the statute, that is, that it was intended to encourage equitable rates for consumers. This standard is closely tied to the first two stated purposes of PURPA, to (1) encourage conservation of energy supplied

by electric utilities and (2) optimize the efficiency of electric utility facilities and resources.

PURPA did not take the primary responsibility over electric utility rates from the states. The Title I standards impose certain obligations on state regulatory commissions and give certain rights to persons to go before state regulatory commissions and state courts. However, under PURPA and its amendments, states retain primary responsibility with respect to retail electric rates. PURPA and the three purposes are intended to supplement state law, but do not override state law. Conference Committee Report, pp. 70-71. Also, states may consider other purposes as well that are not specified by PURPA. State commissions are not required to take actions that conflict with state law. The intention was to preserve the discretion of state commissions that is provided by state law - except to the extent that Title I imposes procedural requirements, such as requirements to hold hearings and consider and make a determination. Conference Committee Report, p. 71.

Section 269-16 of the Hawaii Revised Statutes ("HRS") not only encourages equitable rates for consumers. It requires rates to be just and reasonable and prohibits unreasonable discrimination between localities, or between users or consumers, under substantially similar conditions. HRS 269-16 and Chapter 6-61 of the Hawaii Administrative Rules prescribe procedures to consider utility rate proposals and to determine whether the proposed rates are just, reasonable and non-discriminatory. It is in this ratemaking process that the underlying purpose of PURPA to encourage equitable rates for consumers is met. Since such a process already exists, it is not necessary for the Commission to adopt the federal standards to encourage equitable rates for consumers. Rather, rates should be

established based on the specific needs and circumstances that currently exist on this island. As I have explained above, the Company has proposed in this proceeding time-of-use rates which are appropriate for the islands of Maui County but it is not proposing critical peak pricing or real-time pricing which are not suited for this island at this time.

Q. Has the Commission previously considered whether to adopt any Energy Policy Act standards?

A. Yes. In Docket No. 94-0203, by Order No. 13387, filed July 19, 1994, the Commission instituted a proceeding to consider and determine the appropriateness of implementing the energy efficiency standards established by the Energy Policy Act of 1992 for electric utilities under PURPA Section 111. By Decision and Order No. 14454, filed January 12, 1996, the Commission concluded that it need not adopt the federal standards in order to be in compliance with Section 111 of PURPA, as amended by the Energy Policy Act of 1992.

Q. Please summarize MECO's position.

A. MECO has independently and proactively proposed to offer time-of-use rate options to all customer rate classes that give customers the ability to manage their electric bills by modifying their energy consumption. HECO is also investigating AMI solutions that may enable future and/or modified time-of-use rate options. HECO's AMI research and its proposed time-of-use tariffs are consistent with the standards put forth by the Energy Policy Act of 2005. Thus, it is not necessary for the Commission to adopt the EPACT 2005 time-based rates standards.

SUMMARY

Q. Please summarize your testimony.

A. In this testimony, I have explained MECO's ECAC proposal which includes the incorporation of a DG component as MECO's affiliates have also proposed in recent rate cases. Second, I have explained MECO's position that its ECAC complies with the provisions of Act 162, that the current level of ECAC fuel price risk sharing is appropriate, and that no change is necessary to the current ECAC risk sharing approach. Third, I have described MECO's current and proposed time-of-use offerings and have shown that it is not necessary for the Commission to adopt the EPACT 2005 time-based rates standards.

Q. Does this conclude your testimony?

A. Yes, it does.

ALAN K.C. HEE

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company, Inc. 220 South King Street Honolulu, Hawaii 96813
POSITION:	Manager, Energy Services Department
YEARS OF SERVICE:	21 Years
EDUCATION:	MBA, University of Hawaii, 1982 BS, Civil Engineering Cornell University, NY, 1974
OTHER QUALIFICATIONS:	Registered Professional Engineer, Hawaii Civil Engineering Branch
OTHER EXPERIENCE:	Director, Forecasts Division Energy Services Department, 1995-2004 Director, Forecasting Division Rate and Regulatory Affairs Dept., 1991-1995 Planning Analyst, Forecasting Division Rate and Regulatory Affairs Dept., 1986-1991 Operations Engineer GASCO, Inc., Hilo 1982-1986 Peace Corps Volunteer Fiji Islands, 1974-1976

Maui Electric Company, Ltd.

2007 TEST YEAR ENERGY COST ADJUSTMENT FACTORS
DIRECT TESTIMONY

	ENERGY COST ADJUSTMENT FACTOR PRESENT RATES		ENERGY COST ADJUSTMENT FACTOR PROPOSED RATES	
Maui Division	13.954	¢/KWH	0.000	¢/KWH
Lanai Division	13.913	¢/KWH	0.000	¢/KWH
Molokai Division	15.774	¢/KWH	0.000	¢/KWH

Source: MECO-1904, 1906, 1909 - 1912

Maui Electric Company, Ltd.

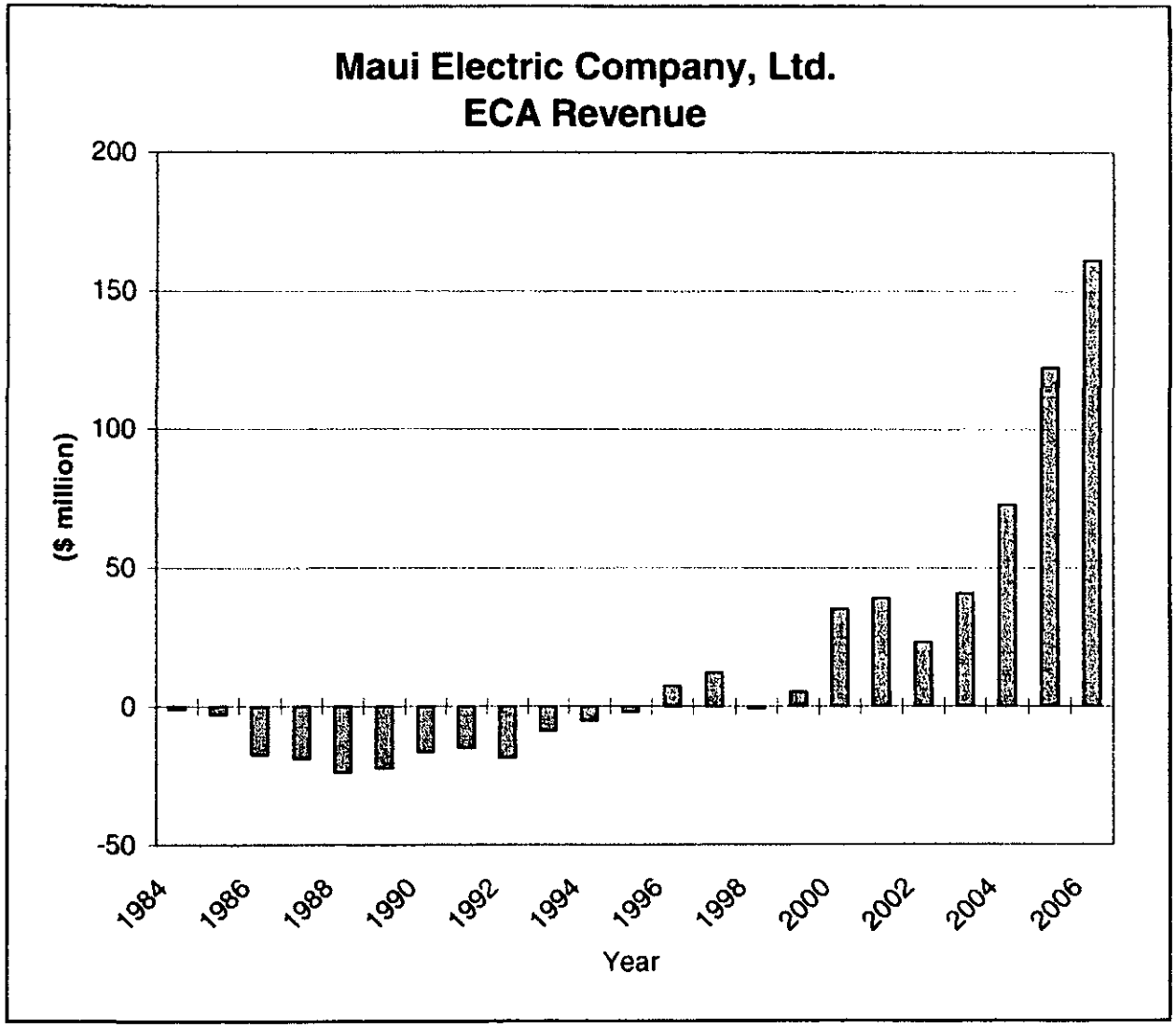
BASE FUEL ENERGY CHARGE AND
FIXED EFFICIENCY FACTOR (OR SALES HEAT RATE)

Line		Rate Proceeding	Docket No. 97-0346, Apr 1999		
			Maui	**Lanai**	**Molokai**
1	Base Fuel Energy, ¢/kWh		4.5937	9.0620	5.3991
	Fuel Price				
2	Industrial, $/bbl		14.21	- - - -	- - - -
3	Diesel, $/bbl		25.78	45.31	27.40
	Base Composite Cost				
4	Generation , ¢/mil btu		369.60	773.27	467.54
5	Purchased Energy, ¢/kWh		5.028	- - - -	- - - -
	Fixed Efficiency Factor or				
6	Sales Heat Rate, btu/kWh of sales		11,032	10,678	10,522

Year	ECA Revenue ($ million) **
1984	-1.077
1985	-2.971
1986	-17.561
1987	-19.069
1988	-23.941
1989	-22.491
1990	-16.748
1991	-14.953
1992	-18.814
1993	-8.707
1994	-5.147
1995	-1.992
1996	7.438
1997	12.112
1998	-0.678
1999	5.233
2000	35.320
2001	39.108
2002	23.227
2003	40.794
2004	72.754
2005	122.418
2006	161.018

** Includes Revenue Taxes

Note:
Positive values are collections.
Negative values are returns.



MAUI ELECTRIC COMPANY, LTD.
MAUI DIVISION
ENERGY COST ADJUSTMENT FILING

PRESENT RATES

Line		
1	Effective Date	2007 Test Year - Direct
	Supersedes Factor of	

OIL-FIRED GENERATION COMPONENT

Line		
	OIL PRICES, ¢/MBTU	
2	Industrial	948.90
3	Diesel	1,792.83
3a	Hana DG	0.00
	OIL BTU MIX, %	
4	Industrial	29.19%
5	Diesel	70.80%
5a	Hana DG	0.01%
6	COMPOSITE GENERATION COST, ¢/MBTU, {Lines (2x4) + Lines (3x5)}	1,546.31
7	% Input to System kWh Mix	83.42%
8	Efficiency Factor, mbtu/kWh	0.011032
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH, {Lines (6x7x8)}	14.23053
10	BASE GENERATION COST, ¢/MBTU	369.60
11	Base % Input to System kWh Mix	91.79
12	Efficiency Factor, mbtu/kWh	0.011032
13	WEIGHTED BASE GEN. COST ¢/KWH, {Lines (10x11x12)}	3.74267
14	COST LESS BASE { Line 9-13 }	10.48786
15	Multiplier to Include Rev. Tax Requirement	1.0975
16	GENERATION FACTOR, ¢/KWH { Lines (14x15) }	11.51043

PURCHASED POWER COMPONENT

Line			
	PURCHASED POWER PRICES, ¢/KWH		
17	HC&S - Regular	- On Peak	20.270
18		- Off Peak	18.450
19	HC&S - Emergency	- On Peak	20.270
20		- Off Peak	18.450
21	HC&S - Unscheduled	- On Peak	20.270
22		- Off Peak	18.450
23	Kaheawa Wind	- On Peak	12.0884
24		- Off Peak	10.8333
25	Makila Hydro	- On Peak	20.270
26		- Off Peak	18.450
27	Other (<100 kW)		0.000
	PURCHASED POWER KWH MIX, %		
28	HC&S - Regular	- On Peak	27.67%
29		- Off Peak	13.22%
30	HC&S - Emergency	- On Peak	0.00%
31		- Off Peak	0.00%
32	HC&S - Unscheduled	- On Peak	1.32%
33		- Off Peak	0.00%
34	Kaheawa Wind	- On Peak	31.54%
35		- Off Peak	25.84%
	Makila Hydro	- On Peak	0.24%
		- Off Peak	0.17%
36	Other (<100 kW)		0.00%
37	COMPOSITE COST OF PURCHASE ENERGY, ¢/KWH		15.007
38	% Input to System kWh Mix		16.58%
39	WEIGHTED COMP. PURCH. ENERGY COST, ¢/KWH, {Lines (35x36)}		2.48816
40	BASE PURCHASED ENERGY COMPOSITE COST, ¢/KWI		5.028
41	Base % Input to System kWh Mix		8.21
42	WEIGHTED BASE PURCH. ENERGY COST, ¢/KWH, Lines {38x39}		0.41280
43	COST LESS BASE {LINE (37-40)}		2.07536
44	Loss Factor		1.073
45	Multiplier to Include Rev. Tax Requirement		1.0975
46	PURCHASED ENERGY FCTR, ¢/KWH {Lines (41x42x43}		2.44398

SYSTEM COMPOSITE CALCULATIONS

Line		
45	FUEL AND PURCHASED ENERGY FACTOR, ¢/KWH {Lines 16+44}	13.954
46	ADJUSTMENT, ¢/KWH	0.000
47	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	0.000
48	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH	13.954

Reference: MECO-1902, MECO-WP-1904

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
Comparison of Composite Costs of Central Station Generation
at Present and Proposed Rates

2007 Test Year - Direct Testimony

Line		(A) At Current Effective Rates	(B) At Proposed Rates	(C) Difference (B) - (A)
	FUEL PRICES, ¢/mmbtu			
1	Industrial	948.90	953.85	4.95
2	Diesel	1,792.83	1,792.83	0.00
3	DG	0.00	0.00	0.00
	BTU MIX, %			
4	Industrial	29.19	29.19	0.00
5	Diesel	70.80	70.81	0.01
6	DG	0.01	0.00	(0.01)
		100.00	100.00	0.00
7	COMPOSITE COST OF GENERATION ¢/mmbtu	1,546.31	1,547.93	1.62

Source:
Col (A) : MECO-1904
Col (B) : MECO-1906

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct (page 1 of 2)

Line		
1	Effective Date	2007 Test Year - Direct
2	Supercedes Factors of	

GENERATION COMPONENT

	CENTRAL STATION	
	FUEL PRICES, ¢/mmbtu	
3	Industrial	953.85
4	Diesel	1,792.83
5	Other	0.00
	BTU MIX, %	
6	Industrial	29.19
7	Diesel	70.81
8	Other	0.00
		100.00
9	COMPOSITE COST OF GENERATION, CNTRL STN + OTHER ¢/mmbtu	1,547.93
10	% Input to System kWh Mix	83.41

EFFICIENCY FACTOR, mmbtu/kWh

	(A)	(B)	(C)	(D)
	Fuel Type	Eff Factor mmbtu/kwh	Percent of Centrl Stn + Other	Weighted Eff Factor
11	Industrial	0.015311	20.30	0.003108
12	Diesel	0.009460	79.70	0.007540
13	Other	0.010648	0.00	0.000000

(Lines 15, 16, 17): Col(B) x Col(C) = Col(D)

14	Weighted Efficiency Factor, mmbtu/kWh [lines 15(D) + 16(D) + 17(D)]	0.010648
15	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (13x14x18))	13.74794
16	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu	1,547.93
17	Base % Input to Sys kWh Mix	83.41
18	Efficiency Factor, mmbtu/kwh	0.010648
19	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (20x21x22))	13.74794
20	COST LESS BASE (line(19-23))	0.00000
21	Revenue Tax Req Multiplier	1.0975
22	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (24x25))	0.00000

	DG ENERGY COMPONENT	
23	COMPOSITE COST OF DG ENERGY, ¢/kWh	22.250
24	% Input to System kWh Mix	0.01
25	WTD COMP DG ENRGY COST, ¢/kWh (Lines 27 x 28)	0.00223
26	BASE DG ENERGY COMP COST	22.250
27	Base % Input to System kWh Mix	0.01
28	WTD BASE DG ENERGY COST, ¢/kWh (Line 30 x 31)	0.00223
29	Cost Less Base (Line 29 - 32)	0.00000
30	Loss Factor	1.065
31	Revenue Tax Req Multiplier	1.0975
32	DG FACTOR, ¢/kWh (Line 33 x 34 x 35)	0.00000

	SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh	
33	Cntrl Stn+Other (line 26)	0.00000
34	DG (line 36)	0.00000
35	TOTAL GENERATION FACTOR, ¢/kWh (lines 37 + 38)	0.00000

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct (page 2 of 2)

Line	PURCHASED ENERGY COMPONENT			
	PURCHASED ENERGY PRICE, ¢/kWh			
36	HC&S - Regular	- On Peak	20.270	
37		- Off Peak	18.450	
38	HC&S - Emergency	- On Peak	20.270	
39		- Off Peak	18.450	
40	HC&S - Unscheduled	- On Peak	20.270	
41		- Off Peak	18.450	
42	Kaheawa Wind	- On Peak	12.088	
43		- Off Peak	10.833	
44	Makila Hydro	- On Peak	20.270	
45		- Off Peak	18.450	
	PURCHASED ENERGY KWH MIX, %			
46	HC&S - Regular	- On Peak	27.67	
47		- Off Peak	13.22	
48	HC&S - Emergency	- On Peak	0.00	
49		- Off Peak	0.00	
50	HC&S - Unscheduled	- On Peak	1.32	
51		- Off Peak	0.00	
52	Kaheawa Wind	- On Peak	31.54	
53		- Off Peak	25.84	
54	Makila Hydro	- On Peak	0.24	
55		- Off Peak	0.17	
			100.00	
56	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh		15.007	
57	% Input to System kWh Mix		16.58	ok
58	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (60x61))		2.48816	
59	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh		15.007	
60	Base % Input to Sys kWh Mix		16.58	
61	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (63 x 64))		2.48816	
62	COST LESS BASE(lines (62 - 65))		0.00000	
63	Loss Factor		1.065	
64	Revenue Tax Req Multiplier		1.0975	
65	PURCHSD ENERGY FCTR, ¢/kWh (lines (66 x 67 x 68))		0.00000	

Line	SYSTEM COMPOSITE	
66	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (39 + 69))	0.00000
67	Adjustment, ¢/kWh	0.000
68	ECA Reconciliation Adjustment	0.000
69	ECA FACTOR, ¢/kWh (lines (70 + 71 + 72))	0.000

Reference: MECO-1907, MECO-WP-1904, pp. 1 and 5, MECO-WP-1906

Maui Electric Company, Ltd. - Maui Division

FIXED AND WEIGHTED EFFICIENCY FACTORS
2007 Test Year - Direct Testimony
At Proposed Rates

	Industrial	Diesel	Other	Total	
1 **Fixed Efficiency Factor**	**0.015311**	**0.009460**	**0.010648**		mbtu/kwh
2 Gen Mwh %	20.30	79.70	0.00	100.00	%
3 Weighted Efficiency Factor (line 1 x line 2)	0.003108	0.007540	0.000000	0.010648	mbtu/kwh

Reference:
1 MECO-WP-1907
2 MECO-WP-1906, p. 4

Maui Electric Company, Ltd. - Maui Division

ILLUSTRATION OF
THE PROPOSED WEIGHTED COMPOSITE GENERATION COST IN THE ECAC CALCULATIONS MECHANISM
2007 Test Year - Direct Testimony

As Proposed in Base Rates:

	Industrial	Diesel	Other	Total	
1 Fixed Efficiency Factor	0.015311	0.009460	0.010648		mbtu/kwh
2 Gen Mwh %	20.30	79.70	0.00	100.00	%
3 Weighted Efficiency Factor (line 1 x line 2)	0.003108	0.007540	0.000000	0.010648	mbtu/kwh

For illustration purposes,
assume during a month the kWh percent of industrial, diesel and other to the total Generation - Central Station percent are the following:

Industrial	20.0	%
Diesel	80.0	%
Other	0.0	%
	100.0	%

Assume there are no changes to the Industrial, Diesel, DG and Purchased Power fuel prices from proposed rates. Also no changes to the kwh % mix between Central Station, DG and Purchased Power.
Note: For illustration purposes only, assume no change to the btu mix %.

The Weighted Efficiency Factor for that month is as follows:

	Industrial	Diesel	Other	Total	
1 Fixed Efficiency Factor	0.015311	0.009460	0.010648		mbtu/kwh
2 Gen Mwh %	20.00	80.00	0.00	100.00	%
3 Weighted Efficiency Factor (line 1 x line 2)	0.003062	0.007568	0.000000	0.010630	mbtu/kwh

The result is an ECA factor of -0.026 cents/kwh. (Refer to MECO-1908 page 3)

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Illustration of a Month with
the Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct Illustration (page 1 of 2)

Line		
1	Effective Date	2007 Test Year - Direct Illustration
2	Supercedes Factors of	

GENERATION COMPONENT

CENTRAL STATION

	FUEL PRICES, ¢/mmbtu	
3	Industrial	953.85
4	Diesel	1,792.83
5	Other	0.00
	BTU MIX, %	
6	Industrial	29.19
7	Diesel	70.81
8	Other	0.00
		100.00
9	COMPOSITE COST OF GENERATION, CNTRL STN + OTHER ¢/mmbtu	1,547.93
10	% Input to System kWh Mix	83.41

EFFICIENCY FACTOR, mmbtu/kWh

	(A) Fuel Type	(B) Eff Factor mmbtu/kwh	(C) Percent of Cntrl Stn + Other	(D) Weighted Eff Factor
11	Industrial	0.015311	20.00	0.003062
12	Diesel	0.009460	80.00	0.007568
13	Other	0.010648	0.00	0.000000
	(Lines 15, 16, 17): Col(B) x Col(C) = Col(D)			
14	Weighted Efficiency Factor, mmbtu/kWh (lines 15(D) + 16(D) + 17(D))			0.010830

15	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (13x14x18))	13.72470
16	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu	1,547.93
17	Base % Input to Sys kWh Mix	83.41
18	Efficiency Factor, mmbtu/kwh	0.010648
19	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (20x21x22))	13.74794
20	COST LESS BASE (line(19-23))	(0.02324)
21	Revenue Tax Req Multiplier	1.0975
22	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (24x25))	(0.02551)

DG ENERGY COMPONENT

23	COMPOSITE COST OF DG ENERGY, ¢/kWh	22.250
24	% Input to System kWh Mix	0.01
25	WTD COMP DG ENRGY COST, ¢/kWh (Lines 27 x 28)	0.00223
26	BASE DG ENERGY COMP COST	22.250
27	Base % Input to System kWh Mix	0.01
28	WTD BASE DG ENERGY COST, ¢/kWh (Line 30 x 31)	0.00223
29	Cost Less Base (Line 29 - 32)	0.00000
30	Loss Factor	1.065
31	Revenue Tax Req Multiplier	1.0975
32	DG FACTOR, ¢/kWh (Line 33 x 34 x 35)	0.00000

SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh

33	Cntrl Stn+Other (line 26)	-0.02551
34	DG (line 36)	0.00000
35	TOTAL GENERATION FACTOR, ¢/kWh (lines 37 + 38)	-0.02551

MAUI ELECTRIC COMPANY, LTD. - MAUI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Illustration of a Month with
the Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct Illustration (page 2 of 2)

Line	PURCHASED ENERGY COMPONENT		
	PURCHASED ENERGY PRICE, ¢/kWh		
36	HC&S - Regular	- On Peak	20.270
37		- Off Peak	18.450
38	HC&S - Emergency	- On Peak	20.270
39		- Off Peak	18.450
40	HC&S - Unscheduled	- On Peak	20.270
41		- Off Peak	18.450
42	Kaheawa Wind	- On Peak	12.088
43		- Off Peak	10.833
44	Makila Hydro	- On Peak	20.270
45		- Off Peak	18.450
	PURCHASED ENERGY KWH MIX, %		
46	HC&S - Regular	- On Peak	27.67
47		- Off Peak	13.22
48	HC&S - Emergency	- On Peak	0.00
49		- Off Peak	0.00
50	HC&S - Unscheduled	- On Peak	1.32
51		- Off Peak	0.00
52	Kaheawa Wind	- On Peak	31.54
53		- Off Peak	25.84
54	Makila Hydro	- On Peak	0.24
55		- Off Peak	0.17
			100.00
56	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh		15.007
57	% Input to System kWh Mix		16.58 ok
58	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (60x61))		2.48816
59	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh		15.007
60	Base % Input to Sys kWh Mix		16.58
61	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (63 x 64))		2.48816
62	COST LESS BASE(lines (62 - 65))		0.00000
63	Loss Factor		1.065
64	Revenue Tax Req Multiplier		1.0975
65	PURCHSD ENERGY FCTR, ¢/kWh (lines (66 x 67 x 68))		0.00000

Line	SYSTEM COMPOSITE	
66	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (39 + 69))	(0.02551)
67	Adjustment, ¢/kWh	0.000
68	ECA Reconciliation Adjustment	0.000
69	**ECA FACTOR, ¢/kWh (lines (70 + 71 + 72))**	**(0.026)**

Reference: MECO-1906

MAUI ELECTRIC COMPANY, LTD.
LANAI DIVISION
ENERGY COST ADJUSTMENT FILING

PRESENT RATES

Line		
1	Effective Date	2007 Test Year - Direct
	Supersedes Factor of	

OIL-FIRED GENERATION COMPONENT

Line		
	OIL PRICES, ¢/MBTU	
2	Industrial	0.00
3	Diesel	1,960.44
	OIL BTU MIX, %	
4	Industrial	0.00
5	Diesel	100.00
6	COMPOSITE GENERATION COST, ¢/MBTU {Lines (2X4) + Lines (3X5)}	1,960.44
7	% Input to System kWh Mix	100.00%
8	Efficiency Factor, Mbtu/kWh	0.010678
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH {Lines (6X7X8)}	20.93358
10	BASE GENERATION COST, ¢/MBTU	773.27
11	Base % Input to System kWh Mix	100.00%
12	Efficiency Factor, Mbtu/kWh	0.010678
13	WEIGHTED BASE GEN. COST, ¢/KWH, {Lines (10X11X12)}	8.25698
14	COST LESS BASE {Lines (9-13)}	12.6766
15	Multiplier to Include Rev. Tax Requirement	1.0975
16	GENERATION FACTOR, ¢/KWH Lines (14X15)	13.91257

PURCHASED POWER COMPONENT

Line		
	PURCHASED POWER PRICES, ¢/KWH	
17	- Off Peak	0.000
18	- On Peak	0.000
19	Schedule Q	0.000
	PURCHASED POWER KWH MIX, %	
20	- Off Peak	0.000
21	- On Peak	0.000
22	Schedule Q	0.000
	COMPOSITE COST OF	
23	PURCHASED POWER, ¢/KWH	0.00000
24	% Input to System kWh Mix	0.00%
25	WEIGHTED BASE PURCH ENERGY COST, ¢/KWH {Lines (23X24)}	0.00000
	BASE PURCHASED POWER	
26	COMPOSITE COST ¢/KWH	7.695
27	Base % Input to System kWh Mix	0.00%
28	WEIGHTED BASE PURCH ENERGY COST ¢/KWH {Lines (26x27)}	0.00000
29	COST LESS BASE {LINES (25-28)}	0.000
30	Loss Factor	1.073
31	Multiplier to Include Rev. Tax Requirement	1.0975
32	PURCHASED POWER FACTOR, ¢/KWH {Lines (29X30X31)}	0.00000

Line	**SYSTEM COMPOSITE CALCULATIONS**	
33	FUEL AND PURCHASED ENERGY FACTOR, ¢/KWH {Lines (16+32)}	13.913
34	ADJUSTMENT, ¢/KWH	0.000
35	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	0.000
36	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH	13.913

Reference: MECO-1902, MECO-WP-1909

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct (page 1 of 2)

Line		
1	Effective Date	2007 Test Year - Direct
2	Supercedes Factors of	

GENERATION COMPONENT

	CENTRAL STATION	
	FUEL PRICES, ¢/mmbtu	
3	Industrial	0.00
4	Diesel	1,960.44
5	Other	0.00
	BTU MIX, %	
6	Industrial	0.00
7	Diesel	100.00
8	Other	0.00
		100.00
9	COMPOSITE COST OF GENERATION, CNTRL STN + OTHER ¢/mmbtu	1,960.44
10	% Input to System kWh Mix	100.00

EFFICIENCY FACTOR, mmbtu/kWh

	(A)	(B)	(C)	(D)
	Fuel Type	Eff Factor mmbtu/kwh	Percent of Centrl Stn + Other	Weighted Eff Factor
11	Industrial	0.000000	0.00	0.000000
12	Diesel	0.010577	100.00	0.010577
13	Other	0.010577	0.00	0.000000

(Lines 11, 12, 13): Col(B) x Col(C) = Col(D)

14	Weighted Efficiency Factor, mmbtu/kWh [lines 11(D) + 12(D) + 13(D)]	0.010577
15	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (9x10x14))	20.73557
16	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu	1,960.44
17	Base % Input to Sys kWh Mix	100.00
18	Efficiency Factor, mmbtu/kwh	0.010577
19	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (16x17x18))	20.73557
20	COST LESS BASE (line(15-19))	0.00000
21	Revenue Tax Req Multiplier	1.0975
22	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (20x21))	0.00000

	DG ENERGY COMPONENT	
23	COMPOSITE COST OF DG ENERGY, ¢/kWh	0.000
24	% Input to System kWh Mix	0.00
25	WTD COMP DG ENRGY COST, ¢/kWh (Lines 23 x 24)	0.00000
26	BASE DG ENERGY COMP COST	0.000
27	Base % Input to System kWh Mix	0.00
28	WTD BASE DG ENERGY COST, ¢/kWh (Line 26 x 27)	0.00000
29	Cost Less Base (Line 25 - 28)	0.00000
30	Loss Factor	1.054
31	Revenue Tax Req Multiplier	1.0975
32	DG FACTOR, ¢/kWh (Line 29 x 30 x 31)	0.00000

	SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh	
33	Cntrl Stn+Other (line 22)	0.00000
34	DG (line 32)	0.00000
35	TOTAL GENERATION FACTOR, ¢/kWh (lines 33 + 34)	0.00000

MAUI ELECTRIC COMPANY, LTD. - LANAI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct (page 2 of 2)

Line	PURCHASED ENERGY COMPONENT	
	PURCHASED ENERGY PRICE, ¢/kWh	
36	- On Peak	0.000
37	- Off Peak	0.000
38	Sch Q	0.000
	PURCHASED ENERGY KWH MIX, %	
39	- On Peak	0.00
40	- Off Peak	0.00
41	Sch Q	0.000
42	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh	0.000
43	% Input to System kWh Mix	0.00
44	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (42x43))	0.00000
45	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh	0.000
46	Base % Input to Sys kWh Mix	0.00
47	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (45 x 46))	0.00000
48	COST LESS BASE(lines (44 - 47))	0.00000
49	Loss Factor	1.054
50	Revenue Tax Req Multiplier	1.0975
51	PURCHSD ENERGY FCTR, ¢/kWh (lines (48 x 49 x 50))	0.00000

Line	SYSTEM COMPOSITE	
52	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (35 + 51))	0.00000
53	Adjustment, ¢/kWh	0.000
54	ECA Reconciliation Adjustment	0.000
55	ECA FACTOR, ¢/kWh (lines (52 + 53 + 54))	0.000

Reference: MECO-WP-1909, 1910

MAUI ELECTRIC COMPANY, LTD.
MOLOKAI DIVISION
ENERGY COST ADJUSTMENT FILING

PRESENT RATES

Line		
1	Effective Date	2007 Test Year - Direct
	Supersedes Factor of	

OIL-FIRED GENERATION COMPONENT

Line		
	OIL PRICES, ¢/MBTU	
2	Industrial	0.00
3	Diesel	1,833.50
	OIL BTU MIX, %	
4	Industrial	0.00%
5	Diesel	100.00%
6	COMPOSITE GENERATION COST, ¢/MBTU {Line(2X4)+Line(3X5)}	1,833.50
7	% Input to System kWh Mix	100.0%
8	Efficiency Factor, mbtu/kWh	0.010522
9	WEIGHTED COMPOSITE GEN. COST, ¢/KWH {LINES (6X7X8)}	19.29209
10	BASE GENERATION COST, ¢/MBTU	467.54
11	Base % Input to System kWh Mix	100.00%
12	Efficiency Factor, mbtu/kWh	0.010522
13	WEIGHTED BASE GEN. COST, ¢/KWH {LINES (10X11X12)}	4.91946
14	COST LESS BASE {LINES (9-13)}	14.37263
15	Multiplier to include Rev. Tax Requirement	1.09750
16	GENERATION FACTOR, ¢/KWH LINES (14X15)	15.77396

PURCHASED POWER COMPONENT

Line		
	PURCHASED POWER PRICES, ¢/KWH	
17	- Off Peak	0.000
18	- On Peak	0.000
19	Schedule Q	0.000
	PURCHASED POWER KWH MIX, %	
20	- Off Peak	0.000%
21	- On Peak	0.000%
22	Schedule Q	0.000%
	COMPOSITE COST OF	
23	PURCHASED POWER ¢/KWH	0.000
24	% Input to System kWh Mix	0.0%
25	WEIGHTED COMP. PURCH ENERGY COST, ¢/KWH {Lines (23X24)}	0.00000
	BASE PURCHASED POWER	
26	COMPOSITE COST ¢/KWH	4.448
27	Base % Input to System kWh Mix	0.00%
28	WEIGHTED BASE PURCH ENERGY COST, ¢/KWH {Lines (26X27)}	0.00000
29	COST LESS BASE {Lines (25-28)}	0.00000
30	Loss Factor	1.106
31	Multiplier to Include Rev. Tax Requirement	1.0975
32	PURCHASED POWER FACTOR, ¢/KWH {Lines (29X30X31)}	0.00000

Line	**SYSTEM COMPOSITE CALCULATIONS**	
33	FUEL AND PURCHASED ENERGY FACTOR, ¢/KWH {Lines (16+32)}	15.77396
34	ADJUSTMENT, ¢/KWH	0.000
35	ECA RECONCILIATION ADJUSTMENT, ¢/KWH	0.000
36	ENERGY COST ADJUSTMENT FACTOR, ¢/KWH	15.774

Reference: MECO-1902, MECO-WP-1909

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct (page 1 of 2)

Line		
1	Effective Date	2007 Test Year - Direct
2	Supercedes Factors of	

GENERATION COMPONENT

	CENTRAL STATION	
	FUEL PRICES, ¢/mmbtu	
3	Industrial	0.00
4	Diesel	1,833.50
5	Other	0.00
	BTU MIX, %	
6	Industrial	0.00
7	Diesel	100.00
8	Other	0.00
		100.00
9	COMPOSITE COST OF GENERATION, CNTRL STN + OTHER ¢/mmbtu	1,833.50
10	% Input to System kWh Mix	100.00

EFFICIENCY FACTOR, mmbtu/kWh

	(A)	(B)	(C)	(D)
	Fuel Type	Eff Factor mmbtu/kwh	Percent of Centrl Stn + Other	Weighted Eff Factor
11	Industrial	0.000000	0.00	0.000000
12	Diesel	0.010823	100.00	0.010823
13	Other	0.010823	0.00	0.000000

(Lines 11, 12, 13): Col(B) x Col(C) = Col(D)

14	Weighted Efficiency Factor, mmbtu/kWh [lines 11(D) + 12(D) + 13(D)]	0.010823
15	WGTD. COMPOSITE CNTRL STN + OTHER GEN COST, ¢/kWh (lines (9x10x14))	19.84397
16	BASE CNTRL STN + OTHER GEN. COST, ¢/mmbtu	1,833.50
17	Base % Input to Sys kWh Mix	100.00
18	Efficiency Factor, mmbtu/kwh	0.010823
19	WEIGHTED BASE CNTRL STN + OTHER GEN COST ¢/kWh (lines (16x17x18))	19.84397
20	COST LESS BASE (line(15-19))	0.00000
21	Revenue Tax Req Multiplier	1.0975
22	CNTRL STN + OTHER GENERATION FACTOR, ¢/kWh (line (20x21))	0.00000

	DG ENERGY COMPONENT	
23	COMPOSITE COST OF DG ENERGY, ¢/kWh	0.000
24	% Input to System kWh Mix	0.00
25	WTD COMP DG ENRGY COST, ¢/kWh (Lines 23 x 24)	0.00000
26	BASE DG ENERGY COMP COST	0.000
27	Base % Input to System kWh Mix	0.00
28	WTD BASE DG ENERGY COST, ¢/kWh (Line 26 x 27)	0.00000
29	Cost Less Base (Line 25 - 28)	0.00000
30	Loss Factor	1.100
31	Revenue Tax Req Multiplier	1.0975
32	DG FACTOR, ¢/kWh (Line 29 x 30 x 31)	0.00000

	SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh	
33	Cntrl Stn+Other (line 22)	0.00000
34	DG (line 32)	0.00000
35	TOTAL GENERATION FACTOR, ¢/kWh (lines 33 + 34)	0.00000

MAUI ELECTRIC COMPANY, LTD. - MOLOKAI DIVISION
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Weighted Generation Efficiency Factor & DG Component

ENERGY COST ADJUSTMENT (ECA) FILING - 2007 Test Year - Direct (page 2 of 2)

Line	PURCHASED ENERGY COMPONENT	
	PURCHASED ENERGY PRICE, ¢/kWh	
36	- On Peak	0.000
37	- Off Peak	0.000
38	Sch Q	0.000
	PURCHASED ENERGY KWH MIX, %	
39	- On Peak	0.00
40	- Off Peak	0.00
41	Sch Q	0.000
42	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh	0.000
43	% Input to System kWh Mix	0.00
44	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (42x43))	0.00000
45	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh	0.000
46	Base % Input to Sys kWh Mix	0.00
47	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (45 x 46))	0.00000
48	COST LESS BASE(lines (44 - 47))	0.00000
49	Loss Factor	1.100
50	Revenue Tax Req Multiplier	1.0975
51	PURCHSD ENERGY FCTR, ¢/kWh (lines (48 x 49 x 50))	0.00000

Line	SYSTEM COMPOSITE	
52	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (35 + 51))	0.00000
53	Adjustment, ¢/kWh	0.000
54	ECA Reconciliation Adjustment	0.000
55	ECA FACTOR, ¢/kWh (lines (52 + 53 + 54))	0.000

Reference: MECO-WP-1909, 1912

MECO T-20
DOCKET NO. 2006-0387

TESTIMONY OF
EDWARD L. REINHARDT

PRESIDENT
MAUI ELECTRIC COMPANY, LIMITED

Subject: Results of Operations,
including Revenue Requirements,
Rate Increase Implementation

INTRODUCTION

Q. Please state your name and business address.

A. My name is Edward L. Reinhardt and my business address is 210 West Kamehameha Avenue, Kahului, Hawaii.

Q. Have you testified earlier in this docket?

A. Yes. I submitted direct testimony in MECO T-1. MECO-100 provides my educational background and work experience.

Q. What will your testimony in MECO T-20 address?

A. My testimony in MECO T-20 will discuss MECO's results of operations, including revenue requirements for test year 2007, and the Company's proposed implementation of the requested increase.

RESULTS OF OPERATIONS

Q. What revenue requirements are reflected in MECO's test year 2007 results of operations?

A. MECO's test year 2007 results of operations reflect revenue requirements of $376,285,000 (based on September 1, 2006 fuel prices) to produce an 8.98% return on MECO's test year 2007 average rate base of $386,040,000 at proposed rates, as shown in MECO-2001. At present rates, MECO's results of operations include total estimated operating revenues of $357,308,000 for test year 2007 (based on September 1, 2006 fuel prices), or $18,977,000 less than MECO's test year 2007 revenue requirements.

Q. What are MECO's present rates?

A. MECO's present rates are the base rates that were established as a result of Amended Decision and Order No. 16922 in Docket No. 97-0346 (MECO's 1999 test year rate case).

Q. What would MECO's test year 2007 return on average rate base be for ratemaking purposes without rate relief?

A. MECO's normalized results of operations (based on September 1, 2006 fuel prices) reflect a rate of return on average rate base of 6.24% for the 2007 test year without rate relief, as shown in MECO-2001.

Q. What rate relief is being sought in this docket?

A. MECO is requesting that the Commission approve rates and charges that are designed to produce an additional $18,977,000 (over revenues at present rates and using September 1, 2006 fuel prices) in total operating revenues, as shown on MECO-2001. MECO's proposed rates and charges are included in MECO-108 (Maui Division), MECO-109 (Lanai Division), and MECO-110 (Molokai Division). MECO's proposed rate increase over present rates in total and by rate class for each division, in terms of dollars and by percentage for test year 2007 are reflected in MECO-113.

Q. How much additional operating income will MECO's proposed rates and charges produce?

A. The proposed revenue increase over present rates will increase MECO's estimated test year 2007 operating income by $10,560,000 to produce an 8.98% return on the Company's test year 2007 average rate base of $386,040,000 at proposed rates. MECO's supporting testimonies, exhibits and workpapers provide justification for a fair return of 8.98% on MECO's property that is used or useful for public utility purposes.

Q. How much of the required additional revenues will go towards paying increased taxes?

A. Approximately 44% of the requested increase in revenues ($8,406,000 of the

proposed $18,977,000 increase over present rates) will be used to pay increased County, State, and Federal taxes and fees.

RATE INCREASE IMPLEMENTATION

Q. How does MECO propose to implement its proposed rate increase?

A. MECO proposes to implement the proposed rate increase in two steps:

1) Interim Increase, and

2) Final Increase.

Q. When does MECO request that the proposed Interim Increase be made effective?

A. MECO requests that it be allowed to implement its proposed Interim Increase as soon as practicable after the evidentiary hearing is held. Based on the process followed in recent rate cases, MECO is targeting completion of the evidentiary hearing in the fourth quarter of 2007 or early 2008. MECO is requesting an interim increase as soon as possible. MECO's Results of Operations show that MECO has a need for a rate increase in the 2007 test year. Therefore, MECO requires the requested increase as near to the beginning of 2008 as practicable to provide the Company an opportunity to earn the rate of return on rate base authorized by the Commission in this proceeding. MECO will determine the amount that it is requesting in the Interim Increase at the close of the evidentiary hearing, based on the evidence before the Commission.

Q. When does MECO propose to make the Final Increase effective?

A. The Final Increase would become effective when the Commission issues its final decision and order in this docket. The amount of the Final Increase is to provide for the amount of the total revenue increase authorized but not included in the Interim Increase.

Q. What rate design mechanisms does MECO propose to use to implement the

Interim and Final Increase?

A. MECO proposes that the Interim Increase implemented prior to the Final Increase be structured as surcharges for the various classes based on a percentage of the customer's base charges (i.e., exclusive of Energy Cost Adjustment charges and other surcharges). MECO requests that the rate design changes proposed in the Application (and explained by Mr. Young in MECO T-18) be implemented when the Final Increase is implemented.

SUMMARY

Q. Please summarize the Company's presentation in this proceeding.

A. MECO has presented substantial evidence in its 20 written testimonies (with exhibits and workpapers) sponsored by 16 different witnesses to support MECO's requested rate increase. MECO's Results of Operations for the normalized 2007 test year indicate that a rate increase of $18,977,000 over revenues at present rates based on September 1, 2006 fuel prices is necessary to permit MECO an opportunity to earn a rate of return of 8.98% on its average rate base of $386,040,000 at proposed rates.

MECO has made substantial investments in production, transmission and distribution plant and engaged in programs and operational activities that are essential for MECO to continue to meet the energy requirements on the islands of Maui, Lanai and Molokai and to maintain and improve service quality for its customers.

In order for MECO to maintain its financial integrity and ability to attract capital for its capital expenditures, it is essential that the proceeding in this docket progress as expeditiously as possible, and that adequate rate relief be granted the Company on a timely basis. Thus, MECO urges that the Commission grant:

1) an appropriate Interim Increase as soon as practicable, pursuant to Section 269-16(d), HRS

2) a Final Increase (which would incorporate an Interim Increase) such that the combined impact of the Interim and Final Increases yields the requested increase of $18,977,000 over present rates for the normalized 2007 test year (based on September 1, 2006 fuel prices)

3) approval of the proposed revisions to MECO's rate schedules and rules as described by Mr. Peter Young in MECO T-18

Q. Does this conclude your testimony?

A. Yes, it does.

MAUI ELECTRIC COMPANY, LIMITED

EDWARD L. REINHARDT

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Maui Electric Company, Limited (MECO) 210 Kamehameha Avenue, Kahului, HI 96732
Position:	President Maui Electric Company, Limited (May 2001 to present)
Years of Service:	21 Years
Education:	Bachelor of Science in Electronic Engineering Northrop University, 1976 Edison Electric Institute, 1993 Public Utilities Executives' Course, 1994
Previous Positions:	Manager, Energy Delivery Department Maui Electric Company, Limited 1999-2001 Manager, Engineering Department Maui Electric Company, Limited 1990-1999 Senior Electrical Engineer Engineering Department Maui Electric Company, Limited 1989-1990 Staff Engineer Engineering Department Maui Electric Company, Limited 1988-1989 Electrical Designer Engineering Department Maui Electric Company, Limited 1986-1988

Systems Engineer
Kauai Electric Company
1982-1986

Chief Engineer
Molokai Electric Company
1981-1982

Power Systems Engineer
Amfac's Lihue Plantation
1980-1981

Electrical Field Engineer
General Electric Company
1976-1980

Previous Testimony:

Docket No. 6571
Waikapu Line Relocation

Docket No. 6797
Special Purpose Revenue Bond

Docket No. 7000
MECO Rate Increase

Maui Electric Company, Ltd.
Proposed Rate Design - Base Case
Total Company
Results of Operations
2007
($ Thousands)

	Present Rates	Additional Amount	Revenue Requirements to Produce 8.98% Return on Average Rate Base
Electric Sales Revenue	355,773	18,753	374,526
Other Operating Revenue	1,535	224	1,759
TOTAL OPERATING REVENUES	357,308	18,977	376,285
Fuel	180,465		180,465
Purchased Power	33,982		33,982
Production	21,015		21,015
Transmission	2,277		2,277
Distribution	6,336		6,336
Customer Accounts	3,086		3,086
Allowance for Uncoll. Accounts	214	11	225
Customer Service	1,541		1,541
Administration & General	13,560		13,560
Operation and Maintenance	262,476	11	262,487
Depreciation & Amortization	28,872		28,872
Amortization of State ITC	(518)		(518)
Taxes Other Than Income	33,068	1,680	34,748
Interest on Customer Deposits	233		233
Income Taxes	9,071	6,726	15,797
TOTAL OPERATING EXPENSES	333,202	8,417	341,619
OPERATING INCOME	24,106	10,560	34,666
AVERAGE RATE BASE	386,261	(221)	386,040
RATE OF RETURN ON AVERAGE RATE BASE	6.24%		8.98%

Maui Electric Company, Ltd.
Proposed Rate Design - Base Case
Maui Division
Results of Operations
2007
($ Thousands)

	Present Rates	Additional Amount	Revenue Requirements to Produce 9.29% Return on Average Rate Base
Electric Sales Revenue	333,075	17,555	350,630
Other Operating Revenue	1,390	202	1,592
TOTAL OPERATING REVENUES	334,465	17,757	352,222
Fuel	167,036		167,036
Purchased Power	33,982		33,982
Production	18,742		18,742
Transmission	2,244		2,244
Distribution	5,644		5,644
Customer Accounts	2,778		2,778
Allowance for Uncoll. Accounts	200	11	211
Customer Service	1,538		1,538
Administration & General	12,550		12,550
Operation and Maintenance	244,714	11	244,725
Depreciation & Amortization	26,598		26,598
Amortization of State ITC	(475)		(475)
Taxes Other Than Income	30,918	1,572	32,490
Interest on Customer Deposits	216		216
Income Taxes	9,122	6,294	15,416
TOTAL OPERATING EXPENSES	311,093	7,877	318,970
OPERATING INCOME	23,372	9,880	33,252
AVERAGE RATE BASE	358,230	(207)	358,023
RATE OF RETURN ON AVERAGE RATE BASE	6.52%		9.29%

Maui Electric Company, Ltd.
Proposed Rate Design - Base Case
Lanai Division
Results of Operations
2007
($ Thousands)

	Present Rates	Additional Amount	Revenue Requirements to Produce 3.02% Return on Average Rate Base
Electric Sales Revenue	10,067	531	10,598
Other Operating Revenue	38	8	46
TOTAL OPERATING REVENUES	10,105	539	10,644
Fuel	6,176		6,176
Purchased Power	0		0
Production	1,095		1,095
Transmission	0		0
Distribution	238		238
Customer Accounts	139		139
Allowance for Uncoll. Accounts	6	0	6
Customer Service	1		1
Administration & General	344		344
Operation and Maintenance	7,999	0	7,999
Depreciation & Amortization	1,243		1,243
Amortization of State ITC	(20)		(20)
Taxes Other Than Income	952	48	1,000
Interest on Customer Deposits	6		6
Income Taxes	(175)	191	16
TOTAL OPERATING EXPENSES	10,005	239	10,244
OPERATING INCOME	100	300	400
AVERAGE RATE BASE	13,257	(6)	13,251
RATE OF RETURN ON AVERAGE RATE BASE	0.75%		3.02%

Maui Electric Company, Ltd.
Proposed Rate Design - Base Case
Molokai Division
Results of Operations
2007
($ Thousands)

	Present Rates	Additional Amount	Revenue Requirements to Produce 6.86% Return on Average Rate Base
Electric Sales Revenue	12,631	667	13,298
Other Operating Revenue	107	14	121
TOTAL OPERATING REVENUES	12,738	681	13,419
Fuel	7,253		7,253
Purchased Power	0		0
Production	1,178		1,178
Transmission	33		33
Distribution	454		454
Customer Accounts	169		169
Allowance for Uncoll. Accounts	8	0	8
Customer Service	2		2
Administration & General	666		666
Operation and Maintenance	9,763	0	9,763
Depreciation & Amortization	1,031		1,031
Amortization of State ITC	(23)		(23)
Taxes Other Than Income	1,198	60	1,258
Interest on Customer Deposits	11		11
Income Taxes	124	241	365
TOTAL OPERATING EXPENSES	12,104	301	12,405
OPERATING INCOME	634	380	1,014
AVERAGE RATE BASE	14,774	(8)	14,766
RATE OF RETURN ON AVERAGE RATE BASE	4.29%		6.86%