Hawaiian Electric Industries, Inc.

2006 Annual Report to Shareholders

Appendix A

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Contents

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, tsunamis and the potential effects of global warming;
- 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 peak reserve margins on Oahu continue 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 (ECACs);
- 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, the potential regulation of greenhouse gas emissions and governmental fees and assessments); decisions by the Public Utilities Commission of the State of Hawaii (PUC) in rate cases (including decisions on ECACs) 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, for example, 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 and Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48 regarding uncertainty in income taxes), continued regulatory accounting under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and the possible effects of applying FIN 46R, "Consolidation of Variable Interest Entities," and Emerging Issues Task Force Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease," to PPAs 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 (e.g., Item 1A. Risk Factors) and in other periodic reports 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.

Selected Financial Data

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2006	2005	2004	2003	2002
(dollars in thousands, except per share amounts)					
Results of operations					
Revenues	$ 2,460,904	$ 2,215,564	$ 1,924,057	$ 1,781,316	$ 1,653,701
Net income (loss)					
Continuing operations	$ 108,001	$ 127,444	$ 107,739	$ 118,048	$ 118,217
Discontinued operations	–	(755)	1,913	(3,870)	–
	$ 108,001	$ 126,689	$ 109,652	$ 114,178	$ 118,217
Basic earnings (loss) per common share					
Continuing operations	$ 1.33	$ 1.58	$ 1.36	$ 1.58	$ 1.63
Discontinued operations	–	(0.01)	0.02	(0.05)	–
	$ 1.33	$ 1.57	$ 1.38	$ 1.53	$ 1.63
Diluted earnings per common share	$ 1.33	$ 1.56	$ 1.38	$ 1.52	$ 1.62
Return on average common equity-continuing operations *	9.3%	10.5%	9.4%	11.1%	12.0%
Return on average common equity	9.3%	10.4%	9.5%	10.7%	12.0%
Financial position **					
Total assets	$ 9,891,209	$ 9,951,577	$ 9,719,257	$ 9,307,700	$ 9,039,121
Deposit liabilities	4,575,548	4,557,419	4,296,172	4,026,250	3,800,772
Other bank borrowings	1,568,585	1,622,294	1,799,669	1,848,388	1,843,499
Long-term debt, net	1,133,185	1,142,993	1,166,735	1,064,420	1,106,270
HEI- and HECO-obligated preferred securities of trust subsidiaries	–	–	–	200,000	200,000
Preferred stock of subsidiaries – not subject to mandatory redemption	34,293	34,293	34,405	34,406	34,406
Stockholders' equity	1,095,240	1,216,630	1,210,945	1,089,031	1,046,300
Common stock					
Book value per common share **	$ 13.44	$ 15.02	$ 15.01	$ 14.36	$ 14.21
Market price per common share					
High	28.94	29.79	29.55	24.00	24.50
Low	25.69	24.60	22.96	19.10	17.28
December 31	27.15	25.90	29.15	23.69	21.99
Dividends per common share	1.24	1.24	1.24	1.24	1.24
Dividend payout ratio	93%	79%	90%	81%	76%
Dividend payout ratio-continuing operations	93%	78%	91%	78%	76%
Market price to book value per common share **	202%	172%	194%	165%	155%
Price earnings ratio ***	20.4x	16.4x	21.4x	15.0x	13.5x
Common shares outstanding (thousands) **	81,461	80,983	80,687	75,838	73,618
Weighted-average	81,145	80,828	79,562	74,696	72,556
Shareholders ****	35,021	35,645	35,292	34,439	34,901
Employees **	3,447	3,383	3,354	3,197	3,220

* Net income from continuing operations divided by average common equity.

** At December 31. (Note: Stockholders' equity and book value per common share as of December 31, 2006 includes a charge to AOCI pursuant to SFAS No. 158. See Note 8, "Retirement benefits," of HEI's "Notes to Consolidated Financial Statements.")

*** Calculated using December 31 market price per common share divided by basic earnings per common share from continuing operations. The principal trading market for HEI's common stock is the New York Stock Exchange (NYSE).

**** At December 31. Registered shareholders plus participants in the HEI Dividend Reinvestment and Stock Purchase Plan who are not registered shareholders. As of February 21, 2007, HEI had 34,908 registered shareholders and participants.

The Company discontinued its international power operations in 2001. See Note 14, "Discontinued operations," of HEI's "Notes to Consolidated Financial Statements." Also see "Commitments and contingencies" in Note 3 of HEI's "Notes to Consolidated Financial Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" for discussions of certain contingencies that could adversely affect future results of operations and factors that affected reported results of operations (e.g., bank franchise taxes).

On April 20, 2004, the HEI Board of Directors approved a 2-for-1 stock split in the form of a 100% stock dividend with a record date of May 10, 2004 and a distribution date of June 10, 2004. All share and per share information has been adjusted to reflect the stock split for all periods presented.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with HEI's consolidated financial statements and accompanying notes. The general discussion of HEI's consolidated results should be read in conjunction with the segment discussions of the electric utilities and the bank that follow.

HEI Consolidated

Executive overview and strategy

The Company's three strategic objectives, currently, are to operate the electric utility and bank subsidiaries for long-term growth, maintain the annual dividend and increase the Company's financial flexibility by strengthening the balance sheet and maintaining credit ratings.

HEI, through HECO and its electric utility subsidiaries, Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO), provide the only electric public utility service to approximately 95% of Hawaii's population. HEI also provides a wide array of banking and other financial services to consumers and businesses through its bank subsidiary, ASB, Hawaii's third largest financial institution based on asset size.

In 2006, income from continuing operations was $108 million, compared to $127 million in 2005. Basic earnings per share from continuing operations were $1.33 per share in 2006, down 16% from $1.58 per share in 2005 due to lower earnings at the bank and "other" segments, partly offset by slightly higher earnings at the electric utilities. The electric utilities' earnings benefited from interim rate relief and slightly higher kilowatthour (KWH) sales, but were also impacted by higher expenses, which were expected and are expected to continue. The bank's earnings were hurt by the challenging interest rate environment—a flat or inverted yield curve throughout 2006—and higher legal and litigation-related expenses, but the core business performed well as loans grew and deposits stabilized. The "other" segment's $23 million loss in 2006 was larger than the $10 million loss in 2005 primarily due to a one-time net gain of $9 million on the sale of a leveraged lease investment in 2005.

The Company's operations are heavily influenced by Hawaii's economy, which is driven by tourism, the federal government (including the military), real estate and construction. Per the State of Hawaii Department of Business, Economic Development and Tourism (DBEDT), Hawaii real gross state product grew by an estimated 2.7% in 2006 and is expected to grow by a forecasted 2.6% in 2007.

Shareholder dividends are declared and paid quarterly by HEI at the discretion of HEI's Board of Directors. HEI and its predecessor company, HECO, have paid dividends continuously since 1901. The dividend has been stable at $1.24 per share annually since 1998 (split-adjusted). The indicated dividend yield as of December 31, 2006 was 4.6%. HEI's Board believes that HEI should have a payout ratio of 65% or lower on a sustainable basis and that cash flows should support an increase before it considers increasing the common stock dividend above its current level. The dividend payout ratios based on net income for 2006, 2005 and 2004 were 93%, 79% and 90% (payout ratios of 93%, 78% and 91% based on income from continuing operations), respectively. The payout ratio for 2006 was higher due to the lower net income. The payout ratio for 2004 was impacted by a charge to net income of $20 million due to a June 2004 adverse tax ruling and subsequent settlement and an increased number of shares outstanding from the sale of 2 million shares (pre-split) of common stock in March 2004. Without the bank franchise tax charge, the payout ratio for 2004 would have been 76% (77% based on income from continuing operations).

In the first half of 2004, HEI strengthened its balance sheet through a common stock sale and repayment and refinancing of debt.

HEI's subsidiaries from time to time consider various strategies designed to enhance their competitive positions and to maximize shareholder value. These strategies may include the formation of new subsidiaries or the acquisition or disposition of businesses. The Company may from time to time be engaged in preliminary discussions, either internally or with third parties, regarding potential transactions. Management cannot predict whether any of these strategies or transactions will be carried out or, if so, whether they will be successfully implemented.

See the Electric Utility and Bank sections for their respective executive overviews and strategies.

Economic conditions

Note: The statistical data in this section is from public third party sources (e.g., DBEDT, U.S. Census Bureau and Bloomberg).

Because its core businesses provide local electric utility and banking services, HEI's operating results are significantly influenced by the strength of Hawaii's economy. The state's economic growth, which is fueled by the two largest components of Hawaii's economy – tourism and the federal government – is estimated by the DBEDT to have been 2.7% in 2006. DBEDT expects that growth will further moderate to 2.6% in 2007 and 2.5% in 2008.

Following two exceptional years of growth, tourism in Hawaii remained strong with visitor expenditures reaching a record $12 billion in 2006, a 2.9% increase over 2005. 2006 visitor days were slightly lower by 0.3% compared to the 2005 record-high level. State economists expect continued growth in 2007 with projected increases of 1.5% in visitor days and 4.8% in visitor expenditures.

Hawaii was the fifth ranking state in federal government expenditures per capita in the latest available data. For the federal fiscal year ended September 30, 2004 (latest available data), total federal government expenditures in Hawaii, including military expenditures, were $12.2 billion or $9,651 per capita, increasing 8% and 7%, respectively, over fiscal year 2003. Military spending, which is 39% of federal expenditures in Hawaii, increased 6% in 2004 compared to 2003.

The real estate and construction industries in Hawaii also influence HEI's core businesses. The Oahu housing market continued to stabilize in 2006 with home sales volume down by 12.5% compared to 2005. Total dollar sales volume for 2006 was $5.5 billion, down 8.8%, compared to the same period of 2005. However, Oahu home sales prices continued to increase with the average median price for a single-family home of $630,000 for 2006, compared to $590,000 for 2005.

The construction industry continues to remain strong as indicated by an 8% increase in 2006 building permits compared to 2005. Local economists expect a gradual slowing in residential construction as rising costs meet flattening demand. However, it is expected that increased military and commercial construction will be stabilizing factors.

Overall, the outlook for the Hawaii economy remains positive. However, economic growth is affected by the rate of expansion in the mainland U.S. and Japan economies and the growth in military spending, and is vulnerable to uncertainties in the world's geopolitical environment.

Management also monitors (1) oil prices because of their impact on the rates the utilities charge for electricity and the potential effect of increased electricity prices on usage and (2) interest rates because of their potential impact on ASB's earnings, HEI's and HECO's cost of capital and pension costs, and HEI's stock price. Crude oil prices hovered around $70 per barrel in the first half of 2006 due to geopolitical fallout from Iran's renewed nuclear program and risks of supply disruption. Prices remained high during the third quarter of 2006 and came off their high levels toward year-end due to a slowing U.S. economy and lessening concerns about Iran's continuing its nuclear program. The average fuel oil cost per barrel for the electric utilities increased 20% in 2006 compared to 2005. On February 21, 2007, crude oil futures closed at $58.02 per barrel.

For most of 2006, long-term interest rates fluctuated in the 4.0% to 5.25% trading range and the short-end of the yield curve continued to increase. This resulted in an inverted yield curve for most of 2006 which is indicative of a difficult earning environment for ASB. As of December 31, 2006, the yield curve was inverted with a spread between the 10-year and 2-year Treasuries of (0.11)%, compared to the yield curve as of December 31, 2005, with a spread of (0.02)%.

Results of Operations

(dollars in millions, except per share amounts)		2006	% change		2005	% change		2004
Revenues	$	2,461	11	$	2,216	15	$	1,924
Operating income		239	(12)		271	–		271
Income from continuing operations	$	108	(15)	$	128	18	$	108
Loss from discontinued operations		–	NM		(1)	NM		2
Net income	$	108	(15)	$	127	16	$	110
Electric utility	$	75	3	$	73	(10)	$	81
Bank		56	(14)		65	58		41
Other		(23)	NM		(10)	NM		(14)
Income from continuing operations	$	108	(15)	$	128	18	$	108
Basic earnings (loss) per share								
Continuing operations	$	1.33	(16)	$	1.58	16	$	1.36
Discontinued operations		–	NM		(0.01)	NM		0.02
	$	1.33	(15)	$	1.57	14	$	1.38
Dividends per share	$	1.24	–	$	1.24	–	$	1.24
Weighted-average number of common shares outstanding (millions)		81.1	–		80.8	2		79.6
Dividend payout ratio		93%			79%			90%
Dividend payout ratio – continuing operations		93%			78%			91%

NM Not meaningful.

Stock split

On April 20, 2004, HEI announced a 2-for-1 stock split in the form of a 100% stock dividend with a record date of May 10, 2004 and a distribution date of June 10, 2004. All share and per share information above, in the accompanying financial statements and notes and elsewhere in this report have been adjusted to reflect the stock split (unless otherwise noted). See Note 1 of HEI's "Notes to Consolidated Financial Statements."

Bank franchise taxes (consolidated HEI)

The 2004 results of operations include an after-tax charge of $20 million, or $0.25 per share, due to a June 2004 tax ruling and subsequent settlement as discussed in Note 10 of HEI's "Notes to Consolidated Financial Statements" under "ASB state franchise tax dispute and settlement." The following table presents a reconciliation of HEI's consolidated income from continuing operations to income from continuing operations excluding this $20 million charge in 2004. The Company believes the adjusted information below presents results from continuing operations on a more comparable basis for the periods shown. However, net income, or earnings per share, including these adjustments is not a presentation defined under U.S. generally accepted accounting principles (GAAP) and may not be comparable to presentations used by other companies or more useful than the GAAP presentation included in HEI's consolidated financial statements.

Years ended December 31		2006		2005		2004
(dollars in thousands, except per share amounts)						
Income from continuing operations	$	108,001	$	127,444	$	107,739
Basic earnings per share - continuing operations	$	1.33	$	1.58	$	1.36
Cumulative bank franchise taxes, net of taxes, through December 31, 2003	$	–	$	–	$	20,340
As adjusted						
Income from continuing operations	$	108,001	$	127,444	$	128,079
Basic earnings per share - continuing operations	$	1.33	$	1.58	$	1.61
Return on average common equity [1]		9.3%		10.5%		11.2%

[1] Calculated using adjusted income from continuing operations divided by the simple average adjusted common equity.

Taking into account the adjustments in the table above, HEI's 2005 consolidated income from continuing operations would have been flat compared to 2004.

Retirement benefits

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions about future experience. For example, retirement benefits costs are impacted by actual employee demographics (including age and compensation levels), the level of contributions to the plans, earnings and realized and unrealized gains and losses on plan assets and changes made to the provisions of the plans. (No changes were made to the retirement benefit plans' provisions in 2006, 2005 and 2004 that have had a significant impact on costs.) Costs may also be significantly affected by changes in key actuarial assumptions, including the expected return on plan assets and the discount rate. The Company accounts for retirement benefit costs in accordance with SFAS No. 87, "Employers' Accounting for Pensions" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," and thus, changes in obligations associated with the factors noted above may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants.

The assumptions used by management in making benefit and funding calculations are based on current economic conditions. Changes in economic conditions will impact the underlying assumptions in determining retirement benefits costs on a prospective basis. In selecting an assumed discount rate, the Company considered the Moody's Daily Long-Term Corporate Bond Aa Yield Average (which was 5.72% as of December 31, 2006 compared to 5.41% as of December 31, 2005) and changes in this rate from period to period. In addition, the Company also considered the plans' actuarial consultant's cashflow matching analysis based upon bond information provided by Standard & Poors for all high quality bonds (i.e., rated AA- or better) as of December 31, 2006. In selecting an assumed rate of return on plan assets, the Company considers economic forecasts for the types of investments held by the plans (primarily equity and fixed income investments), the plans' asset allocations and the past performance of the plans' assets.

For 2006, the Company's retirement benefit plans' assets generated a total return, net of investment management fees, of 13.5%, resulting in earnings and realized and unrealized gains of $122 million, compared to $65 million for 2005 and $82 million for 2004. The market value of the retirement benefit plans' assets as of December 31, 2006 was $1 billion. See "Liquidity and Capital Resources" below for the Company's cash contributions to the retirement benefit plans.

Based on various assumptions in Note 8 of HEI's "Notes to Consolidated Financial Statements" and assuming no further changes in retirement benefit plan provisions, consolidated HEI's, consolidated HECO's and ASB's accumulated other comprehensive income (AOCI) balance, net of tax benefits, related to the liability for retirement benefits; retirement benefits expense, net of income taxes; and retirement benefits paid and plan expenses were, or are estimated to be, as follows as of the dates or for the periods indicated:

	AOCI balance, net of tax benefits,		Retirement benefits expense, net of income tax benefits				Retirement benefits paid and expenses		
	December 31		Years ended December 31				Years ended December 31		
	2006	2005	(Estimated) 2007 [1]	2006	2005 [2]	2004 [2]	2006	2005	2004
(dollars in millions)									
Consolidated HEI	$(140)	$(1)	$20	$17	$11	$7	$55	$51	$49
Consolidated HECO	(127)	–	16	13	8	4	51	50	47
ASB	(8)	–	2	3	2	2	2	1	1

1 Forward-looking statements subject to risks and uncertainties, including the impact of plan changes during the year, if any, and the impact of actual information when received (e.g., actual participant demographics as of January 1, 2007).

2 Does not include impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

See Note 8 of HEI's "Notes to Consolidated Financial Statements" for further retirement benefits information.

The following tables reflect the sensitivities of the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) as of December 31, 2006, and the sensitivity of 2007 net income, associated with a change in certain actuarial assumptions by the indicated basis points and constitute "forward-looking statements." Each sensitivity below reflects the impact of a change in that assumption.

Actuarial assumption	Change in assumption in basis points	Impact on PBO or APBO	Impact on 2007 net income
(dollars in millions)			
Pension benefits			
Discount rate	+/– 50	$(63)/$70	$3/$(3)
Rate of return on plan assets	+/– 50	NA	2/(2)
Other benefits			
Discount rate	+/– 50	(11)/12	– /(1)
Health care cost trend rate	+/– 100	4/(4)	– / –
Rate of return on plan assets	+/– 50	NA	– / –

NA Not applicable.

Baseline assumptions: 6.0% discount rate; 8.5% asset return rate; 10% medical trend rate for 2007, grading down to 5% for 2012 and thereafter; 5% dental trend rate; and 4% vision trend rate.

"Other" segment

(dollars in millions)	2006	% change	2005	% change	2004
Revenues [1]	(2)	NM	$ 21	134	$ 9
Operating income (loss)	(16)	NM	5	NM	(8)
Net loss	(23)	NM	(10)	NM	(14)

[1] Including writedowns of and net gains and losses from investments.

NM Not meaningful.

The "other" business segment includes results of operations of HEI Investments, Inc. (HEIII), a company primarily holding investments in leveraged leases; Pacific Energy Conservation Services, Inc., a contract services company primarily providing windfarm operational and maintenance services to an affiliated electric utility; HEI Properties, Inc. (HEIPI), a company holding passive, venture capital investments; The Old Oahu Tug Service, Inc. (TOOTS), a maritime freight transportation company that ceased operations in 1999; HEI and HEI Diversified, Inc. (HEIDI), holding companies; and eliminations of intercompany transactions.

- HEIII recorded net income of $3.5 million in 2006, including intercompany interest income and income from leveraged leases. HEIII recorded net income of $16.2 million in 2005, including a gain of $14 million on the sale of its approximate 25% interest in a trust that is the owner/lessor of a 60% undivided interest in a coal-fired electric generating plant in Georgia. Most of the approximately $5 million of income taxes on the sale were recorded at HEI in accordance with the Company's "stand-alone" tax allocation policy. HEIII recorded net income of $1.8 million in 2004, primarily from leveraged leases.

- HEIPI recorded net losses of $1.8 million in 2006, net income of $3.5 million in 2005 and net losses of $0.9 million in 2004, which amounts include income and losses from and/or writedowns of venture capital investments. In 2006, HEIPI recognized $2.6 million in unrealized and realized losses ($1.6 million after-tax) on its investment in Hoku Scientific, Inc. (Hoku), a materials science company focused on clean energy technologies that completed its initial public offering and became a public company in August 2005. In 2005, HEIPI recognized a $4.6 million unrealized gain ($2.9 million after-tax) on its investment in Hoku and recorded lower writedowns of another venture capital investment in a nonpublic company. HEIPI began trading Hoku stock in February 2006 when its lock-up agreement expired. As of December 31, 2006, HEIPI's venture capital investments (including its remaining investment in Hoku) amounted to $2.8 million. In January 2007, HEIPI sold its remaining investment in Hoku with a fair value at December 31, 2006 of $1.2 million for a net after-tax gain of $0.9 million.

• HEI Corporate and the other subsidiaries' revenues in 2004 include a $5.6 million pretax gain ($3.6 million after-tax) on the sale of the income notes that HEI purchased in May and July 2001 in connection with the termination of ASB's investments in trust certificates.

HEI Corporate operating, general and administrative expenses (including labor, employee benefits, incentive compensation, charitable contributions, legal fees, consulting, rent, supplies and insurance) were $12.1 million in 2006, down from $14.8 million in 2005 and $14.9 million in 2004. In 2006, incentive compensation was lower and share-based compensation was lower (as the restricted stock granted in 2006 had no acceleration feature for retirement). HEI Corporate and the other subsidiaries' net loss was $24.5 million in 2006, $30.0 million in 2005 and $15.4 million in 2004, the majority of which is comprised of financing costs. The results for 2006 and 2005 did not include $5.4 million of dividends on ASB preferred stock held by HEIDI, as it had in 2004, due to the redemption of ASB's preferred stock in December 2004, which was followed by a $75 million infusion into ASB of common equity by HEIDI. The results for 2005 include most of the $5 million of income taxes on the $14 million gain on sale by HEIII of the trust interest described above and results for 2004 include a $3.6 million after-tax gain on the sale of the income notes, which amounts are not expected to be recurring.

• The "other" segment's interest expenses were $23.1 million in 2006, $25.9 million in 2005 and $27.6 million in 2004. In 2006, financing costs decreased due to the use of lower-costing short-term commercial paper borrowings to replace or temporarily refinance maturing medium-term notes. In 2005, financing costs decreased due to lower interest rates and lower average borrowing balances.

Discontinued operations

In 2001, the HEI Board of Directors adopted a plan to exit the international power business. In 2004, HEI Power Corp. (HEIPC) and its subsidiaries (HEIPC Group) sold the company that holds its interest in Cagayan Electric Power & Light Co., Inc. (CEPALCO) for a nominal gain. Also in 2004, the HEIPC Group transferred its interest in a China joint venture to its partner and another entity and recorded an after-tax gain on disposal of $2 million. In 2005, HEIPC increased its reserve for future expenses by $1 million primarily due to higher than expected arbitration costs in connection with HEI and HEIPC claims under a political risk insurance policy; the arbitration concluded unsuccessfully in 2005. See Note 14 of HEI's "Notes to Consolidated Financial Statements."

Prior to July 1, 2006, all of HEIPC's subsidiaries, except for HEIII, were dissolved. In December 2006, HEIPC's stock in HEIII was transferred to HEI and HEIDI and HEIPC filed articles of dissolution in Hawaii on December 20, 2006. HEI is currently the sole shareholder of HEIII.

Effects of inflation

U.S. inflation, as measured by the U.S. Consumer Price Index (CPI), averaged 2.5% in 2006, 3.4% in 2005, and 3.3% in 2004. Hawaii inflation, as measured by the Honolulu CPI, was 5.9% in 2006, 3.8% in 2005 and 3.3% in 2004. DBEDT forecasts average Honolulu CPI to be 4.0% for 2007. The rate of inflation over the last few years has been trending upward and inflation continues to have an impact on HEI's operations.

Inflation increases operating costs and the replacement cost of assets. Subsidiaries with significant physical assets, such as the electric utilities, replace assets at much higher costs and must request and obtain rate increases to maintain adequate earnings. In the past, the Public Utilities Commission of the State of Hawaii (PUC) has generally approved rate increases to cover the effects of inflation. The PUC granted an interim rate increase in 2005 for HECO and final rate increases in 2001 and 2000 for HELCO and in 1999 for MECO, in part to cover increases in construction costs and operating expenses due to inflation.

Recent accounting pronouncements

See "Recent accounting pronouncements and interpretations" in Note 1 of HEI's "Notes to Consolidated Financial Statements."

Liquidity and capital resources

Selected contractual obligations and commitments

The following tables present Company-aggregated information about total payments due during the indicated periods under the specified contractual obligations and commercial commitments:

December 31, 2006	Payment due by period				
(in millions)	1 year or less	2-3 years	4-5 years	More than 5 years	Total
Contractual obligations					
Deposit liabilities					
Commercial checking	$ 319	$ –	$ –	$ –	$ 319
Other checking	853	–	–	–	853
Savings	1,570	–	–	–	1,570
Money market	202	–	–	–	202
Term certificates	1,212	213	198	9	1,632
Total deposit liabilities	4,156	213	198	9	4,576
Other bank borrowings	787	482	100	200	1,569
Long-term debt, net	10	50	150	923	1,133
Operating leases, service bureau contract and maintenance agreements	29	44	26	32	131
Open purchase order obligations	54	11	3	–	68
Fuel oil purchase obligations (estimate based on January 1, 2007 fuel oil prices)	539	1,078	1,077	1,617	4,311
Power purchase obligations– minimum fixed capacity charges	118	234	237	1,130	1,719
Total (estimated)	$5,693	$2,112	$1,791	$3,911	$13,507

December 31, 2006	
(in millions)	
Other commercial commitments to ASB customers	
Loan commitments (primarily expiring in 2007)	$ 24
Loans in process	117
Unused lines and letters of credit	1,000
	$ 1,141

The tables above do not include other categories of obligations and commitments, such as interest (on deposit liabilities, other bank borrowings and long-term debt), trade payables, amounts that will become payable in future periods under collective bargaining and other employment agreements and employee benefit plans, obligations that may arise under indemnities provided to purchasers of discontinued operations and potential refunds of amounts collected under interim D&Os of the PUC. As of December 31, 2006, the fair value of the assets held in trusts to satisfy the obligations of the qualified pension plans exceeded the pension plans' accumulated benefit obligation. Thus, no minimum funding requirements for retirement benefit plans have been included in the tables above.

See Note 3 of HEI's "Notes to Consolidated Financial Statements" for a discussion of fuel and power purchase commitments.

The Company believes that its ability to generate cash, both internally from electric utility and banking operations and externally from issuances of equity and debt securities, commercial paper and bank borrowings, is adequate to maintain sufficient liquidity to fund its contractual obligations and commercial commitments in the tables above, its forecasted capital expenditures and investments, its expected retirement benefit plan contributions and other cash requirements in the foreseeable future.

The Company's total assets were $9.9 billion as of December 31, 2006 and $10.0 billion as of December 31, 2005.

The consolidated capital structure of HEI (excluding ASB's deposit liabilities, securities sold under agreements to repurchase and advances from the Federal Home Loan Bank (FHLB) of Seattle) was as follows:

December 31	2006		2005	
(dollars in millions)				
Short-term borrowings	$ 177	7%	$ 142	6%
Long-term debt, net	1,133	47	1,143	45
Preferred stock of subsidiaries	34	1	34	1
Common stock equity [1]	1,095	45	1,217	48
	$2,439	100%	$2,536	100%

[1] Includes AOCI charge for retirement benefit plans in accordance with SFAS No. 158 as of December 31, 2006.

As of February 28, 2007, the Standard & Poor's (S&P) and Moody's Investors Service's (Moody's) ratings of HEI securities were as follows:

	S&P	Moody's
Commercial paper	A-2	P-2
Medium-term notes	BBB	Baa2

The above ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating.

HEI's overall S&P corporate credit rating is BBB/Negative/A-2.

The rating agencies use a combination of qualitative measures (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HEI securities. In November 2006, S&P affirmed its corporate credit ratings of HEI and maintained its negative outlook. S&P's ratings outlook "assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years)." S&P indicated:

> 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.

In addition, S&P ranks business profiles from "1" (strong) to "10" (weak). In November 2006, S&P did not change HEI's business profile rank of "6".

In December 2006, Moody's confirmed its issuer ratings and stable outlook for HEI. Moody's stated, "The rating could be downgraded should weaker than expected regulatory support emerge at HECO, including the continuation of regulatory lag, which ultimately causes earnings and sustainable cash flow to suffer."

On August 8, 2006, HEI completed the sale of $100 million of 6.141% Medium-Term Notes, Series D due August 15, 2011, under its registered medium-term note program. The proceeds from the sale were ultimately used to reduce HEI's outstanding commercial paper as it matured. As of December 31, 2006, $96 million of debt, equity and/or other securities were available for offering by HEI under an omnibus shelf registration and an additional $50 million principal amount of Series D notes were available for offering by HEI under its registered medium-term note program.

HEI utilizes short-term debt, principally commercial paper, to support normal operations and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO's cash requirements, including the funding of loans by HECO to HELCO and MECO. HEI had an average outstanding balance of commercial paper for 2006 of $68.5 million and had $63.2 million outstanding as of December 31, 2006. Management believes that if HEI's commercial paper ratings were to be downgraded, it might not be able to sell commercial paper under current market conditions.

Effective April 3, 2006, HEI entered into a revolving unsecured credit agreement establishing a line of credit facility of $100 million, with a letter of credit sub-facility, expiring on March 31, 2011, with a syndicate of eight financial institutions. See Note 6 of HEI's "Notes to Consolidated Financial Statements" for a description of the $100 million credit facility. As of December 31, 2006, the line was undrawn. In the future, the Company may seek to enter into new lines of credit and may also seek to increase the amount of credit available under such lines as management deems appropriate.

Operating activities provided net cash of $286 million in 2006, $218 million in 2005 and $244 million in 2004. Investing activities used net cash of $141 million in 2006, $202 million in 2005 and $540 million in 2004. In 2006, net cash was used in investing activities primarily for HECO's consolidated capital expenditures, net of contributions in aid of construction, and net increases in loans held for investment, partly offset by repayments of investment and mortgage-related securities and sales of mortgage-related securities, net of purchases. Financing activities used net cash of $105 million in 2006 and provided net cash of $22 million in 2005 and $187 million in 2004. In 2006, net cash used in financing activities was affected by several factors, including payment of common stock dividends and net decreases in other bank borrowings and long-term debt, partly offset by net increases in short-term borrowings and deposits and proceeds from the issuance of common stock.

A portion of the net assets of HECO and ASB is not available for transfer to HEI in the form of dividends, loans or advances without regulatory approval. One of the conditions of the merger and corporate restructuring of HECO and HEI requires that HECO maintain a consolidated common equity to total capitalization ratio of not less than 35%, and restricts HECO from making distributions to HEI to the extent it would result in that ratio being less than 35%. In the absence of an unexpected material adverse change in the financial condition of the electric utilities or ASB, such restrictions are not expected to significantly affect the operations of HEI, its ability to pay dividends on its common stock or its ability to meet its debt or other cash obligations. See Note 12 of HEI's "Notes to Consolidated Financial Statements."

Forecasted HEI consolidated "net cash used in investing activities" (excluding "investing" cash flows from ASB) for 2007 through 2009 consists primarily of the net capital expenditures of HECO and its subsidiaries. In addition to the funds required for the electric utilities' construction program (see "Electric utility—Liquidity and capital resources"), approximately $60 million will be required during 2007 through 2009 to repay maturing HEI medium-term notes, which are expected to be repaid with the issuance of common stock under Company plans and dividends from subsidiaries. On December 15, 2006, the HEI Board of Directors determined that the common stock requirements for the HEI Dividend Reinvestment and Stock Purchase Plan (DRIP) and Hawaiian Electric Industries Retirement Savings Plan (HEIRSP) will be satisfied by issuance of new HEI shares (rather than open market purchases), and this change is expected to be implemented commencing in March 2007. Additional debt and/or equity financing may be required to fund unanticipated expenditures not included in the 2007 through 2009 forecast, such as increases in the costs of or an acceleration of the construction of capital projects of the utilities, utility capital expenditures that may be required by new environmental laws and regulations, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements and higher tax payments that would result if tax positions taken by the Company do not prevail. In addition, existing debt may be refinanced prior to maturity (potentially at more favorable rates) with additional debt or equity financing (or both).

As further explained in Note 8 of HEI's "Notes to Consolidated Financial Statements," the Company maintains pension and other postretirement benefit plans. Funding for the qualified pension plans is based upon actuarially determined contributions that consider the amount deductible for income tax purposes and the minimum contribution required under the Employee Retirement Income Security Act of 1974, as amended (ERISA). The Company was not required to make any contributions to the qualified pension plans to meet minimum funding requirements pursuant to ERISA for 2006, 2005 and 2004, but the Company's Pension Investment Committee chose to make tax deductible contributions in those years. The electric utilities' policy is to comply with directives from the PUC to fund the costs of the postretirement benefit plan. These costs are ultimately collected in rates billed to customers. The Company reserves the right to change, modify or terminate the plans and, historically, benefits have been changed from time to time. From time to time in the past, benefits have changed.

Contributions to the retirement benefit plans totaled $13 million in 2006 (comprised of $10 million made by the utilities and $3 million by ASB), $25 million in 2005 and $37 million in 2004 (includes Company payments for nonqualified plans in 2005 and 2004, but not 2006). Contributions to the retirement benefits plans are expected to total $14 million in 2007 ($11 million by the utilities and $3 million by ASB). Depending on the performance of the assets held in the plans' trusts and numerous other factors, additional contributions may be required in the future to meet the minimum funding requirements of ERISA or to pay benefits to plan participants. The Company believes it will have adequate access to capital resources to support any necessary funding requirements.

Off-balance sheet arrangements

Although the Company has off-balance sheet arrangements, management has determined that it has no off-balance sheet arrangements that either have, or are reasonably likely to have, a current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors, including the following types of off-balance sheet arrangements:

(1) obligations under guarantee contracts,
(2) retained or contingent interests in assets transferred to an unconsolidated entity or similar arrangements that serves as credit, liquidity or market risk support to that entity for such assets,
(3) obligations under derivative instruments, and
(4) obligations under a material variable interest held by the Company in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Company, or engages in leasing, hedging or research and development services with the Company.

Following are discussions of the results of operations, liquidity and capital resources of the electric utility and bank segments. Additional segment information is shown in Note 2 of HEI's "Notes to Consolidated Financial Statements."

Electric utility

Executive overview and strategy

The electric utilities are vertically integrated and regulated by the PUC. The island utility systems are not interconnected, which requires that additional reliability be built into the systems, but also means that the utilities are not exposed to the risks of inter-ties. The electric utilities' strategic focus has been to meet Hawaii's growing energy needs through a combination of diverse activities—modernizing and adding needed infrastructure through capital investment, placing emphasis on energy efficiency and conservation, pursuing renewable energy options and technology opportunities (such as combined heat and power and distributed generation (DG)) and taking the necessary steps to secure regulatory support for their plans.

Reliability projects, including projects to increase generation reserves to meet growing peak demand, remain a priority for HECO and its subsidiaries. On Oahu, HECO is in the early permitting stages for a new generating unit, which is projected to be placed in service in 2009, and is making progress with plans to build the East Oahu Transmission Project (EOTP), a needed alternative route to move power from the west side of the island. HECO installed a new Energy Management System in 2006 and is scheduled to complete a new Dispatch Center on Oahu in 2007. PUC approvals have been obtained for the new Outage Management and Customer Information Systems, which will also be integrated. On the island of Hawaii, after years of delay, the two 20 megawatt (MW) combustion turbines at Keahole are operating. On the island of Maui, an 18 MW steam turbine at the Maalaea power plant site was installed in 2006. Further, the utilities have demand-side management (DSM) rebate programs and are considering additional DG at utility-owned sites (e.g., substations) as another measure to potentially help meet growing peak demand.

Major infrastructure projects can have a pronounced impact on the communities in which they are located. The electric utilities continue to expand their community outreach and consultation process so they can better understand and evaluate community concerns early in the process.

With large power users in the electric utilities' service territories, such as the U.S. military, hotels and state and local government, management believes that retaining customers by maintaining customer satisfaction is a critical component in achieving kilowatthour (KWH) sales and revenue growth over time. The electric utilities have established programs that offer these customers specialized services and energy efficiency audits to help them save on energy costs.

In November 2004, HECO filed a request with the PUC to increase base rates, primarily for (1) costs relating to existing and proposed energy conservation and efficiency programs (DSM programs), (2) costs of capital improvement projects, (3) the proposed purchase of additional firm capacity and energy, (4) costs of other measures taken to address peak load increases, and (5) increased operation and maintenance expenses. Interim rate relief was granted in late September 2005. The PUC issued a bifurcation order separating HECO's requests for approval and/or modification of its existing and proposed DSM programs from the rate case proceeding into a new docket (EE DSM Docket). The DSM programs, with certain modifications, were approved in February 2007. See "Most recent rate requests—HECO" and "Other regulatory matters—Demand-side management programs."

In May 2006, December 2006 and February 2007, HELCO, HECO and MECO filed requests with the PUC to increase base rates by $29.9 million, $99.6 million and $19.0 million, respectively. See "Most recent rate requests."

The electric utilities' long-term plan to meet Hawaii's future energy needs includes their support of a range of energy choices, including renewable energy and new power supply technologies such as DG. The PUC has issued a decision and framework in a competitive bidding proceeding and a decision in a DG proceeding (see "Certain factors that may affect future results and financial condition—Consolidated—Competition—Electric utility"). HECO's subsidiary, Renewable Hawaii, Inc. (RHI), has initial approval from the HECO Board of Directors to fund investments by RHI of up to $10 million in selected renewable energy projects to help bring online commercially feasible renewable energy sources in Hawaii.

Net income for HECO and its subsidiaries was $75 million in 2006 compared to $73 million in 2005 and $81 million in 2004. The increase in 2006 was primarily due to the impact of HECO's interim rate increase granted by the PUC in late September 2005, largely offset by increased operation and maintenance expenses (including more extensive maintenance on generating units, which are getting older and are being run harder to meet the higher peak demand for electricity, and higher retirement benefits expense) and higher depreciation expense due to investments in capital projects.

Results of Operations

(dollars in millions, except per barrel amounts)	2006	% change	2005	% change	2004
Revenues [1]	$ 2,055	14	$ 1,806	16	$ 1,551
Expenses					
Fuel oil	782	22	640	32	483
Purchased power	507	11	458	15	399
Other	599	10	546	11	495
Operating income	167	3	162	(7)	174
Allowance for funds used during construction	9	30	7	(15)	8
Net income	75	3	73	(10)	81
Return on average common equity	7.5%		7.1%		8.3%
Average price per barrel of fuel oil [1]	$ 68.13	20	$ 56.61	33	$ 42.67
Kilowatthour sales (millions)	10,116	–	10,090	–	10,063
Cooling degree days (Oahu)	4,520	(9)	4,971	(3)	5,107
Number of employees (at December 31)	2,085	1	2,066	3	2,013

1 The rate schedules of the electric utilities currently contain ECACs through which changes in fuel oil prices and certain components of purchased energy costs are passed on to customers.

- In 2006, the electric utilities' revenues increased by 14%, or $249 million, from 2005 primarily due to higher fuel prices ($200 million), interim rate relief granted by the PUC in late September 2005 ($30 million), slightly higher KWH sales ($13 million), and higher DSM program recovery revenues ($6 million), partly offset by lower shareholder incentives and lost margins ($4 million), including the surcharge transferred to base rates in the interim rate relief granted in September 2005. Since May 26, 2006, HECO and, since September 26, 2006, HELCO and MECO, have discontinued their recovery of lost margins and shareholder incentives for their DSM programs until further order by the PUC, which has resulted in reduced revenues. KWH sales increased 0.3% from 2005 primarily due to new load growth (i.e., increase in number of customers), largely offset by the impacts of cooler and less humid weather and customer conservation. Cooling degree days for Oahu were 9% lower in 2006 compared to 2005. The electric utilities are currently estimating KWH sales for 2007 and 2008 to increase over the prior year by 0.6% and 1.6%, respectively. The higher fuel prices are also reflected in the higher amount of customer accounts receivable and accrued unbilled revenues.

Operating income in 2006 was $5 million higher than in 2005 due primarily to the impact of HECO's interim rate increase in late September 2005, partly offset by higher other expenses, including higher maintenance and retirement benefit expenses, and the discontinuation of the recovery of DSM lost margins and shareholder incentives.

Fuel oil and purchased power expenses in 2006 increased by 22% and 11%, respectively, due primarily to higher fuel prices, which are generally passed on to customers.

Other expenses increased 10% in 2006 due to an 8% (or $13 million) increase in "other operation" expense; a 10% (or $8 million) increase in maintenance expense; a 6% (or $7 million) increase in depreciation expense; and a 14% (or $23 million) increase in taxes, other than income taxes, primarily due to the increase in revenues. "Other operation" expenses increased 8% in 2006 when compared to 2005 due primarily to $5 million higher expenses for production operations (including expenses incurred to sustain or increase generating unit availability and lease rent and operating expenses for distributed generation units on Oahu), higher DSM expenses which are generally passed on to customers through a surcharge, and higher retirement benefits expenses. Pension and other postretirement benefit expenses for the electric utilities increased $9 million over 2005 due in part to the adoption of a 25 basis points lower discount rate as of December 31, 2005. Maintenance expenses increased 10% due to $7 million higher production maintenance expense (primarily due to generating plant maintenance and an increase in the number and greater scope of generating unit overhauls) and $1 million higher transmission and distribution maintenance expense (including higher substation maintenance, vegetation management and distribution line maintenance expenses). Higher depreciation expense was attributable to additions to plant in service in 2005 (including HECO's New Kuahua Substation, Mokuone Substation 46 kilovolt (kV) and 12 kV line extensions, an office building air conditioning replacement and HELCO's Keahole power plant noise mitigation measures).

The trend of increased operation and maintenance (O&M) expenses is expected to continue as the electric utilities expect (1) higher DSM expenses (that are generally passed on to customers through a surcharge, including additional expenses for programs that have been approved pursuant to a final decision and order (D&O) in an EE DSM Docket), (2) higher employee benefit expenses, primarily for retirement benefits, and (3) higher production expenses, primarily to support the increased level of peak demand that has occurred over the past five years.

As a result of load growth on Oahu and other factors, there currently is an increased risk to generation reliability. Existing units are running harder, resulting in more frequent and more extensive maintenance, at times requiring temporary shut downs of these units. Generation reserve margins on Oahu and Maui during peak periods continued to be strained. The electric utilities on Oahu and Maui have taken a number of steps to mitigate the risk of outages, including securing additional purchased power, adding distributed generation at some substations and encouraging energy conservation. The marginal costs of supplying energy to meet growing demand, however, are increasing because of the decreasing peak reserve margin situation, and the trend of cost increases is not likely to ease.

- In 2005, the electric utilities' revenues increased by 16%, or $256 million, from 2004 primarily due to higher fuel prices ($235 million), interim rate relief granted by the PUC in late September 2005 ($10 million) and increased shareholder incentives and lost margins ($6 million), including the surcharge transferred to base rates in the interim rate relief granted in September 2005. KWH sales increased 0.3% from 2004 primarily due to new load growth (i.e., increase in number of customers), largely offset by the impacts of cooler and less humid weather and major commercial repair and renovation projects. Cooling degree days for Oahu were 2.7% lower in 2005 compared to 2004. In addition, customers may have been moderating their energy usage in response to the electric utilities' campaign to promote conservation and efficiency and possibly reacting to higher fuel prices reflected in electric bills. The higher fuel prices are also reflected in the higher amount of customer accounts receivable and accrued unbilled revenues.

Operating income in 2005 was $12 million lower than in 2004 mainly due to higher other expenses, including higher maintenance and retirement benefit expenses.

Fuel oil and purchased power expenses in 2005 increased by 32% and 15%, respectively, due primarily to higher fuel prices, which are generally passed on to customers.

Other expenses increased 11% in 2005 due to a 10% (or $16 million) increase in "other operation" expense; a 6% (or $5 million) increase in maintenance expense; a 7% (or $8 million) increase in depreciation expense; and a 16% (or $23 million) increase in taxes, other than income taxes, primarily due to the increase in revenues. "Other operation" expenses increased 10% in 2005 when compared to 2004 due primarily to higher expenses for production operations (including higher environmental expenses as there was a Department of Health of the State of Hawaii (DOH) emission fee waiver in 2004, which was not repeated in 2005), transmission and distribution operations and retirement benefits. Pension and other postretirement benefit expenses for the electric utilities increased $6.7 million over the same period in 2004 due in part to the HEI Pension Investment Committee's adoption of a 25 basis points lower discount rate as of December 31, 2004. Maintenance expenses increased 6% due to higher production maintenance expense (primarily due to generating plant maintenance and generating unit overhauls) and higher transmission and distribution maintenance expense. Higher depreciation expense was attributable to additions to plant in service in 2004 (including HELCO's CT-4 and CT-5 and HECO's Waiau fuel oil pipeline), offset in part by lower depreciation expense resulting from the PUC's approval in September 2004 of rates and accounting methodology applicable to HECO's depreciable assets on Oahu.

Most recent rate requests

The electric utilities initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. The PUC may grant an interim increase within 10 to 11 months following the filing of the application, however, there is no guarantee of such an interim increase. Similarly, the timing and amount of any final increase is up to the discretion of the PUC. As of February 21, 2007, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (D&O issued on December 11, 1995, based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). The ROACE used for purposes of the interim rate increase in HECO's rate case based on a 2005 test year was 10.70%.

For 2006, the simple average ROACEs (calculated under the rate-making method and reported to the PUC), which calculations included the AOCI charges due to the application of SFAS No. 158, for HECO, HELCO and MECO were 8.19%, 3.88% and 9.86%, respectively; if the AOCI charges due to SFAS No. 158 were excluded, these ROACEs would have been 7.61%, 3.70% and 9.51%, respectively. HECO's actual ROACE continues to be significantly lower than its allowed ROACE primarily because of increased O&M expenses, which are expected to continue and have resulted in HECO seeking rate relief more often than in the past. The interim rate relief granted to HECO by the PUC in September 2005 (see below) was based in part on increased costs of operating and maintaining HECO's system. HELCO's ROACE will continue to be negatively impacted by CT-4 and CT-5 as electric rates will not change for the unit additions unless and until the PUC grants rate relief in the HELCO rate case based on a 2006 test year (see below).

As of February 21, 2007, the return on rate base (ROR) found by the PUC to be reasonable in the most recent final rate decision for each utility was 9.16% for HECO, 9.14% for HELCO and 8.83% for MECO (D&Os noted above). However, the ROR used for purposes of the interim D&O in the HECO rate case based on a 2005 test year was 8.66%. For 2006, the simple average RORs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 6.78%, 4.50% and 7.21%, respectively.

The utilities have had, and may in the future have, significant charges to AOCI related to the funded status of their retirement benefit plans, which decrease their common stock equity. Absent appropriate regulatory relief in rate cases, the resulting increase in the electric utilities' RORs and ROACEs could impact the rates the electric utilities are allowed to charge, which may ultimately result in reduced revenues and lower earnings. See Note 8 of HEI's "Notes to Consolidated Financial Statements."

HECO.

2005 test year rate case. In November 2004, HECO filed a request with the PUC to increase base rates 9.9%, or $99 million in annual base revenues, based on a 2005 test year, a 9.11% ROR and an 11.5% ROACE. The requested increase included transferring the cost of existing DSM programs from a surcharge line item on electric bills into base electricity charges. HECO also requested approval and/or modification of its existing and proposed DSM programs, and associated utility incentive mechanism. Excluding the surcharge transfer amount, the requested net increase to customers was 7.3%, or $74 million.

In March 2005, the PUC issued a bifurcation order separating HECO's requests for approval and/or modification of its existing and proposed DSM programs from the rate case proceeding into a new docket (EE DSM Docket). The issues for the EE DSM Docket include (1) whether, and if so, what, energy efficiency goals should be established, (2) whether the proposed and/or other DSM programs will achieve the established energy efficiency goals and be implemented in a cost-effective manner, (3) what market structures are most appropriate for providing these or other DSM programs, (4) for utility-incurred costs, what cost recovery mechanisms and cost levels are appropriate, (5) whether, and if so, what incentive mechanisms are appropriate to encourage the implementation of DSM programs, and (6) which DSM programs should be approved, modified, or rejected. The parties/participants for all issues include HECO, the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs of the State of Hawaii (Consumer Advocate), the federal Department of Defense (DOD), the County of Maui, two renewable energy organizations, an energy efficiency organization, and an environmental organization. HELCO, MECO, Kauai Island Utility Cooperative, The Gas Company and the County of Kauai are parties/participants solely for issues dealing with statewide energy policies. The U.S. Environmental Protection Agency (EPA) and its consultants also have been involved in an advisory capacity to the PUC, and have submitted comments on the proposed DSM programs and the issues in this proceeding. See "Other regulatory matters—Demand-side management programs" below for additional information on this docket and a discussion of the PUC's Interim D&O issued on April 26, 2006.

In September 2005, HECO, the Consumer Advocate and the DOD reached agreement (subject to PUC approval) among themselves on most of the issues in the rate case proceeding, excluding the portion of the original rate case bifurcated into the EE DSM Docket. The remaining significant issue not resolved among the parties was the appropriateness of including in rate base approximately $50 million related to HECO's prepaid pension asset, net of deferred income taxes.

Later in September 2005, the PUC issued its interim D&O (with tariff changes effective September 28, 2005 and amounts collected refundable, with interest, to ratepayers to the extent they exceed the amount approved in the final D&O). For purposes of the interim D&O, the PUC included HECO's prepaid pension asset in rate base (with an annual rate increase impact of approximately $7 million).

The following amounts were included in HECO's rebuttal, the Consumer Advocate's and the DOD's testimonies and exhibits (as adjusted to exclude the transferred surcharge amount of $12 million); the settlement agreement with the Consumer Advocate and the DOD; and the PUC's interim D&O:

	Pre-Settlement				
(dollars in millions)	HECO rebuttal	Consumer Advocate	Department of Defense	HECO (per settlement)	Interim increase[1]
Net additional revenues [2]	$51	$11	$7	$42	$41
ROACE (%)	11	8.5-10	9	10.7	10.7
ROR (%)	8.83	7.85	7.71	8.66	8.66
Average rate base	$1,109	$1,065	$1,062	$1,109	$1,109

1 Effective September 28, 2005, subject to refund with interest pending the final outcome of the case.

2 Excludes $12 million transferred from a surcharge to base rates for existing energy efficiency programs.

The adoption of revenue, expense, rate base and cost of capital amounts (including the ROACE and ROR) for purposes of an interim rate increase does not commit the PUC to accept any such amounts in its final D&O.

On June 19, 2006, the PUC issued an order in HECO's pending rate case based on a 2005 test year, indicating that the record in the pending case has not been developed for the purpose of addressing the factors in Act 162. Act 162, which was effective in June 2006, requires the PUC to consider certain specific factors in evaluating fuel adjustment clauses. See "Energy cost adjustment clauses" in Note 3 of HEI's "Notes to Consolidated Financial Statements." The PUC's order requested the parties in the rate case proceeding to meet informally to determine a procedural schedule to address the issues relating to HECO's ECAC that are raised by Act 162. The parties in the rate case proceeding are HECO, the Consumer Advocate, and the DOD.

On June 30, 2006, HECO and the Consumer Advocate filed a stipulation requesting that the PUC not review the Act 162 ECAC issues in the pending rate case based on a 2005 test year since HECO's application was filed and the record in the proceeding was completed before Act 162 was signed into law, and the settlement agreement entered into by the parties in the rate case included a provision allowing the existing ECAC to be continued. On August 7, 2006, an amended stipulation was filed in substantially the same form as the June 30, 2006 stipulation, but also included the DOD. Management cannot predict whether the PUC will accept the disposition of the Act 162 issue proposed in the amended stipulation or, if not, the procedural steps or procedural schedule that will be adopted to address the issues that are raised by Act 162, the ultimate outcome of these issues, the effect of these issues on the operation of the ECAC as it relates to the electric utilities or the timing of the PUC's issuance of a final D&O in HECO's pending rate case based on a 2005 test year.

2007 test year rate case. On December 22, 2006, HECO filed a request with the PUC for a general rate increase of $99.6 million, or 7.1% over the electric rates currently in effect, based on a 2007 test year, an 8.92% rate of ROR, an 11.25% ROACE and a $1.214 billion average rate base. HECO's electric rates currently in effect include the interim rate increase discussed above of $53 million ($41 million net additional revenues) granted by the PUC in September 2005, which is subject to a final D&O from the PUC, and is subject to refund with interest if and to the extent that the final D&O provides for a lesser increase. If the additional revenues from the interim increase were ultimately not included in rates, the total increase requested would be $151.5 million. This rate case excluded DSM surcharge revenues and associated incremental DSM costs because certain DSM issues, including cost recovery, are being addressed in the EE DSM Docket.

HECO's application includes a proposed new tiered rate structure for residential customers to reward customers who practice energy conservation with lower electric rates for lower monthly usage. The proposed rate increase includes costs incurred to maintain and improve reliability, such as a New Dispatch Center building and associated equipment and the Energy Management System that became operational in 2006, new substations, a new outage management system to be added in 2007 and increased O&M expenses.

The application addresses the ECAC provisions of Act 162 and requests the continuation of HECO's ECAC. On December 29, 2006, the electric utilities' Report on Power Cost Adjustments and Hedging Fuel Risks (ECAC Report) was filed with the PUC. The ECAC Report was prepared by the electric utilities' consultant who was retained to determine whether their existing ECACs are in compliance with Act 162. The testimonies filed in the latest rate cases for HECO, HELCO and MECO included or incorporated the ECAC Report, which concluded that (1) the electric utilities' ECACs are well-designed, and benefit the electric utilities and their ratepayers, and (2) the ECACs comply with the statutory requirements of Act 162. With respect to hedging, the consultants concluded that (1) hedging of oil by HECO would not be expected to reduce fuel and purchased power costs and in fact would be expected to increase the level of such costs, and (2) even if rate smoothing is a desired goal, there may be more effective means of meeting the goal, and there is no compelling reason for the electric utilities to use fuel price hedging as the means to achieving the objective of increased rate stability.

HECO's application requests a return on HECO's pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of deferred taxes) in rate base. In a separate proceeding, the electric utilities requested the PUC approval to record as a regulatory asset for financial reporting purposes, the amounts that would otherwise be charged to AOCI in stockholders' equity as a result of adopting SFAS No. 158, which request was denied. HECO's application, filed before that decision was issued, assumed that the amounts that would otherwise be charged to AOCI in stockholder's equity would be recorded as a regulatory asset for financial reporting purposes (and used for ratemaking purposes). HECO's book equity (financial reporting equity) will be lower than that assumed in the rate increase application because of the charges to AOCI as a result of recording a pension and other postretirement benefits liability after implementing SFAS No. 158 on December 31, 2006. HECO will propose in its rebuttal testimony to restore the book equity (financial reporting equity) for the amounts that were charged against equity (i.e., AOCI) in determining the equity balance for ratemaking purposes. The authorized ROACE found to be fair in a rate case is applied to the equity balance in determining the utility's weighted cost of capital, which is the rate of return applied to the rate base in determining the utility's revenue requirements and rate increase in a rate case. If the equity balance is not restored for ratemaking purposes, the utility's position is that a higher ROE will be required.

<u>HELCO</u>. In May 2006, HELCO filed a request with the PUC to increase base rates by $29.9 million, or 9.24% in annual base revenues, based on a 2006 test year, an 8.65% ROR, an 11.25% ROACE and a $369 million average rate base. HELCO's application includes a proposed new tiered rate structure, which would enable most residential users to see smaller increases in the range of 3% to 8%. The tiered rate structure is designed to minimize the increase for residential customers using less electricity and is expected to encourage customers to take advantage of solar water heating programs and other energy management options. In addition, HELCO's application proposes new time-of-use service rates for residential and commercial customers. The proposed rate increase would pay for improvements made to increase reliability, including transmission and distribution line improvements and the two generating units at the Keahole power plant (CT-4 and CT-5), and increased O&M expenses. The application requests the continuation of HELCO's ECAC. HELCO has filed testimonies and a consultant report to address the ECAC provisions of Act 162.

The PUC held public hearings on HELCO's application in June 2006. The PUC granted Keahole Defense Coalition's motion to participate in this proceeding. In February 2007, the Consumer Advocate submitted its testimony in the proceeding, recommending a revenue increase of $16.6 million based on its proposed ROR of 7.95%, a ROACE ranging between 9.50% and 10.25% and a proposed average rate base of $345 million. The Consumer Advocate recommended adjustments of $21.5 million to HELCO's rate base for certain costs relating to the CT-4 and CT-5 generating units at Keahole (primarily a portion of HELCO's AFUDC, land use permitting costs, and related litigation expenses). In the filing, the Consumer Advocate's consultant concluded that HELCO's ECAC provides a fair sharing of the risks of fuel cost changes between HELCO and its ratepayers in a manner that preserves the financial integrity of HELCO without the need for frequent rate filings.

Keahole Defense Coalition (which as a participant in the proceeding is limited to responding to discovery requests, filing a statement of position and responding to questions at any evidentiary hearing) submitted a Position Statement in which it contended that the PUC should exclude from rate base a greater amount of the CT-4 and CT-5 costs than proposed by the Consumer Advocate.

Among the actions the Consumer Advocate or Keahole Defense Coalition claim to have been imprudent were the decision to site the generation at Keahole and HELCO’s attempts to expedite the addition of generation, even though the PUC, in its 1994 decision approving the commitment of expenditures for CT-4, found that HELCO had an urgent need for generation in the 1994-1995 time frame, recognized that permitting problems might delay CT-4, and concluded that, in light of present and foreseeable circumstances, the location of CT-4 at Keahole was reasonable.

HELCO plans to submit its rebuttal to the Consumer Advocate’s testimony and the Keahole Defense Coalition’s statement of position in March 2007. The rebuttal testimony will also propose to restore book equity (financial reporting equity) for the amounts that were charged against equity as of December 31, 2006 (i.e., AOCI) in determining the equity balance for ratemaking purposes. The procedural schedule also includes settlement discussions and discovery of HELCO’s rebuttal testimony prior to the evidentiary hearings scheduled in May 2007. The earliest that any increase, if granted, may go into effect is expected to be in the second quarter of 2007.

MECO. In February 2007, MECO filed a request with the PUC to increase base rates by $19.0 million, or 5.3% in annual base revenues, based on a 2007 test year, an 8.98% ROR, an 11.25% ROACE and a $386 million average rate base. MECO’s application includes a proposed new tiered rate structure for residential customers to reward customers who practice energy conservation with lower electric rates for lower monthly usage. The proposed rate increase would pay for improvements to increase reliability, including two new generating units added since MECO’s last rate case (which was based on a 1999 test year) at its Maalaea Power plant (M19, a 20 MW combustion turbine placed in service in 2000 and M18, an 18 MW steam turbine placed in service in October 2006 to complete the installation of a second dual-train combined cycle unit), and transmission and distribution infrastructure improvements. The proposed rate structure also includes continuation of MECO’s ECAC. MECO has filed testimonies to address the ECAC provisions of Act 162. The application requests a return on MECO’s pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of deferred income taxes) in rate base. The application also proposes to restore book equity (in determining the equity balance for ratemaking purposes) for the amounts that were charged against equity (i.e., to AOCI) as a result of recording a pension and other postretirement benefits liability after implementing SFAS No. 158.

Depreciation rates and accounting

In October 2002, HECO filed an application with the PUC for approval to change its depreciation rates based on a study of depreciation expense for 2000 and to change to vintage amortization accounting for selected plant accounts. In March 2004, HECO and the Consumer Advocate reached an agreement, which the PUC approved in September 2004. In accordance with the agreement, HECO changed its depreciation rates and changed to vintage amortization accounting for selected plant accounts effective September 1, 2004, resulting in slightly lower depreciation in the remainder of 2004 and for future years than would have been recorded under the previous rates and method.

Other regulatory matters

Demand-side management programs. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, for the continuation of HECO's three commercial and industrial DSM programs and two residential DSM programs until HECO's next rate case. These agreements were in lieu of HECO continuing to seek approval of new 5-year DSM programs and provided that DSM programs to be in place after HECO's next rate case would be determined as part of the case. Under the agreements, HECO agreed to cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current "authorized return on rate base" (i.e. the rate of return on rate base found by the PUC to be reasonable in the most recent rate case for HECO). HECO also agreed it would not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. At the time of the agreement, HECO indicated to the Consumer Advocate that it planned to seek alternative incentive mechanisms for DSM programs in its rate case. In November 2001, the PUC issued orders that, subject to certain reporting requirements and other conditions, approved the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case.

In November 2004, HECO filed a request for a rate increase based on a 2005 test year and approval and/or modification of its existing and proposed DSM programs, and associated utility incentive mechanism. In March 2005, the PUC issued a bifurcation order separating HECO's requests for approval and/or modification of its existing and proposed DSM programs from the rate case proceeding based on a 2005 test year into a new EE DSM docket. The bifurcation order allowed HECO to temporarily continue, in the manner currently employed, its existing three commercial and industrial DSM programs and two residential DSM programs, until further order by the PUC. As a result of the bifurcation order in HECO's rate case, HECO has been continuing its existing DSM programs and cost recovery mechanisms, including the recovery of incremental program costs for its energy efficiency DSM programs through a surcharge mechanism, pending the resolution of the EE DSM Docket.

Following the bifurcation order, HECO also continued to accrue shareholder incentives and lost margins. In December 2005 in the EE DSM Docket, HECO requested PUC approval, on an interim basis, for certain modifications to its existing energy efficiency DSM programs and a new interim DSM program (Interim DSM Proposals). HECO did not request shareholder incentives and lost margins for its proposed new interim DSM program, but did so for the modifications to its existing energy efficiency programs. In January 2006, the Consumer Advocate filed comments on HECO's Interim DSM Proposals, which generally supported the proposals, but objected to the continued recovery of shareholder incentives and lost margins for the existing energy efficiency DSM programs, as well as for the modifications.

In April 2006, the PUC issued an Interim Decision and Order (Interim D&O) approving HECO's requests to modify its existing DSM programs and implement its proposed interim DSM program. However, the PUC also ordered that HECO's recovery of lost margins and shareholder incentives for its DSM programs be discontinued within 30 days of the Interim D&O (i.e., by May 26, 2006), until further order by the PUC. Lost margins and shareholder incentives are estimated and recorded in the year earned, and collected from ratepayers in the current year (lost margins) or the following year (shareholder incentives). Revenues that HECO had previously expected to accrue for lost margins and shareholder incentives from May 26, 2006 through the end of 2006 were estimated at $2.1 million, or $1.2 million in after-tax net income.

In October 2001, HELCO and MECO had reached similar agreements with the Consumer Advocate regarding the continuation of their DSM programs and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO were allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but were permitted in the orders to request to extend the time of such accrual and recovery for up to one additional year.

Based on the Interim D&O in the EE DSM docket, on May 25, 2006, HELCO and MECO filed a request for a one-year extension for the recovery of HELCO and MECO's lost margins and shareholder incentives or until final resolution of the EE DSM Docket. On September 19, 2006, the Consumer Advocate opposed an extension beyond September 26, 2006 (i.e., one year beyond the interim rate increase in the HECO rate case). On October 4 and 5, 2006, the PUC issued orders that allowed HELCO and MECO to accrue lost margins and shareholder incentives only up to September 26, 2006. Revenues that HELCO and MECO had previously expected to accrue for lost margins and shareholder incentives from September 27, 2006 through the end of 2006 were estimated at $1.6 million, or $0.9 million in after-tax net income.

One of the conditions to the interim continuation of the DSM programs requires the utilities and the Consumer Advocate to review, every six months, the economic and rate impacts resulting from implementing the agreement. In 2003, 2005 and 2006, none of the electric utilities exceeded their respective authorized RORs. In 2004, only MECO exceeded its authorized ROR, resulting in a reduction of revenues from shareholders incentives and lost margins for MECO for 2004 by $1.0 million (recorded in December 2004). In reviewing HELCO's ROR for 2003, the Consumer Advocate raised an issue regarding Keahole settlement expenses and HELCO agreed to refund, with interest, all of the lost margins and shareholder incentives it had earned in 2003. In June 2004, HELCO recorded reduced revenues of $1.1 million to reflect the lost margins and shareholder incentives for 2003 that were refunded to ratepayers in August 2004.

In 2004, HECO and the Consumer Advocate reached agreement on a residential load management program and a commercial and industrial load management program and the PUC approved HECO's programs. Implementation of these programs began in early 2005. The residential load management program includes a monthly electric bill credit for eligible customers who participate in the program, which allows HECO to disconnect the customer's residential electric water heaters from HECO's system to reduce system load when deemed necessary by HECO. The commercial and industrial load management program provides an incentive on the portion of the demand load that eligible customers allow to be controlled or interrupted by HECO. In addition, if HECO interrupts the load, an incentive is paid on the kilowatthours interrupted. On November 22 and December 29, 2006, HECO filed proposed modifications to its Residential Direct Load Control (RDLC) and Commercial and Industrial Direct Load Control (CIDLC) programs. On December 29, 2006, the PUC approved the RDLC program modifications.

On February 13, 2007, the PUC issued its D&O in the EE DSM Docket. In the D&O, the PUC authorized HECO to implement its seven proposed EE DSM programs (which include enhancements to its five existing programs), with certain modifications, as well as a proposed Residential Customer Energy Awareness (RCEA) Program. In approving the EE DSM portfolio, the PUC found that: (1) the EE DSM portfolio should achieve Energy Efficiency goals and should be implemented in a cost-effective manner; and (2) the EE DSM programs are necessary to help address HECO's current reserve capacity shortfall.

In addition, the PUC required that the administration of all EE DSM programs be turned over to a non-utility, third-party administrator, with the transition to the administrator, funded through a public benefits fund surcharge, to become effective around January 2009. The PUC indicated that a new docket will be opened to select a third-party administrator and to refine details of the new market structure. Unlike the EE DSM programs, load management DSM programs will continue to be administered by the utilities. The utilities also may compete for implementation of the EE DSM programs and the RCEA Program and the PUC did not determine any of the parameters of the eligibility of HECO or its subsidiaries or the selection criteria that will be used in awarding program implementation.

The D&O also provides for HECO's recovery of DSM program costs and utility incentives. With respect to cost recovery, the PUC continues to permit recovery of reasonably-incurred DSM implementation costs, under the Integrated Resource Plan (IRP) framework. Specifically, during the transition period under the current utility market structure, labor costs are to be recovered through base rates, while non-labor costs will be recovered via a surcharge. DSM utility incentives will be derived from a graduated performance-based schedule of net system benefits. In order to qualify for an incentive, the utility must meet MW and MWh reduction goals for its EE DSM programs in both the commercial and industrial, and residential sectors. The amount of the annual incentive is capped at $4 million for HECO, and may not exceed either 5% of the net system benefits, or utility earnings opportunities foregone by implementing DSM programs in lieu of supply-side rate based investments. Negative incentives will not be imposed for underperformance.

The PUC further indicated that a new docket will be opened to approve HECO's periodic DSM program reports and field any of HECO's requests for DSM program modifications. The issue of decoupling sales from revenues, which had been proposed by one party to the proceeding, was deferred to a future proceeding.

Avoided cost generic docket. In May 1992, the PUC instituted a generic investigation, including all of Hawaii's electric utilities, to examine the proxy method and formula used by the electric utilities to calculate their avoided energy costs and Schedule Q rates. In general, Schedule Q rates are available to customers with cogeneration and/or small power production facilities with a capacity of 100 KWHs or less who buy/sell power from/to the electric utility. The parties to the 1992 docket include the electric utilities, the Consumer Advocate, the DOD, and representatives of existing or potential IPPs. In March 1994, the parties entered into and filed a Stipulation to Resolve Proceeding, which is subject to PUC approval. The parties could not reach agreement with respect to certain of the issues, which are addressed in Statements of Position filed in March 1994. In July 2004, the PUC ordered the parties to review and update the agreements, information and data contained in the stipulation and file such information. On December 29, 2006, the parties filed an Updated Stipulation to Resolve Proceeding with the PUC. The parties agreed that avoided fuel costs will be determined using a computer production simulation model except for Lanai and Molokai, and agreed on certain parameters that would be used to calculate avoided costs. The parties were not in total agreement on certain other issues which will need to be decided by the PUC. HECO and it subsidiaries, the Consumer Advocate and DOD filed a joint statement of position that they oppose retroactive compensation to Wailuku River Hydro for transformer losses, as proposed by Mauna Kea Power Company, Inc. and the Hawaii Agriculture Research Center.

Integrated resource planning, requirements for additional generating capacity and adequacy of supply. The PUC issued an order in 1992 requiring the energy utilities in Hawaii to develop IRPs, which may be approved, rejected or modified by the PUC. The goal of integrated resource planning is the identification of demand- and supply-side resources and the integration of these resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. The utilities' proposed IRPs are planning strategies, rather than fixed courses of action, and the resources ultimately added to their systems may differ from those included in their 20-year plans. Under the PUC's IRP framework, the utilities are required to submit annual evaluations of their plans (including a revised five-year program implementation schedule) and to submit new plans on a three-year cycle, subject to changes approved by the PUC. Prior to proceeding with the DSM programs, separate PUC approval proceedings must be completed.

The utilities are entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, including the costs of DSM programs, either through a surcharge or through their base rates. Under procedural schedules for the IRP cost proceedings, the utilities can begin recovering their incremental IRP costs in the month following the filing of their actual costs incurred for the year, subject to refund with interest pending the PUC's final D&O approving recovery in the docket for each year's costs. HELCO and HECO now recover IRP costs through base rates and MECO continues to recover its costs through a surcharge.

In December 2006, the PUC issued a D&O allowing recovery of all but $46,000 of the $2.7 million of IRP costs the utilities incurred in 1995 and, in February 2007, issued a D&O allowing recovery of all but $1,000 of the $1.8 million of IRP costs the utilities incurred in 1996. However, the Consumer Advocate has objected to the recovery of $2.9 million (before interest) of the $8.4 million of incremental IRP costs incurred by the utilities during the 1997-2005 period, and the PUC's decision is pending on these costs. In addition, MECO incurred approximately $0.7 million of incremental IRP costs for 2006, for which the Consumer Advocate has not yet stated its position. As of December 31, 2006, the amount of revenues, including interest and revenue taxes, that the electric utilities recorded in 1997 through 2006 for IRP cost recoveries, subject to refund with interest, amounted to $14 million.

See “Demand-side management programs” above, which includes a discussion of the agreements between the utilities and the Consumer Advocate concerning prior caps on the recovery of lost margins and shareholders incentives.

HECO’s IRP. In October 2005, HECO filed its third IRP (IRP-3), which proposes multiple solutions to meet Oahu’s future energy needs, including renewable energy resources, energy efficiency, conservation, technology (such as CHP and DG) and central station generation (including a combustion turbine generating unit in 2009 described under “HECO’s 2009 Campbell Industrial Park generating unit” and a possible 180 MW coal unit in 2022). In addition, HECO currently plans for all existing generating units to remain in operation (future environmental considerations permitting) beyond the 20-year IRP planning period (2006-2025). In June 2006, the PUC granted an environmental group’s motion to intervene in the proceeding and ordered the parties to determine the issues, procedures and schedule for the docket and to file a stipulated procedural order. In September 2006, the parties to the IRP-3 docket filed for PUC approval a stipulation for the parties to meet informally to address IRP-3 process issues and to attempt to reach a follow-up stipulation that will allow for the disposition of the IRP-3 docket without a final D&O approving the IRP-3 plan and action plan. If the parties are unable to reach a follow-up stipulation, then the parties will file a stipulated procedural order setting forth the issues, procedures and schedule for the docket, or if the parties are unable to reach agreement on a stipulated procedural order, then the parties will submit separate proposed procedural orders for PUC consideration.

HELCO’s IRP. In September 1998, HELCO filed its second IRP with the PUC, and updated it in 1999 and 2004. On the supply side, HELCO’s second IRP focused on the planning for generating unit additions after near-term additions. The near-term additions included installing two 20 MW CTs at its Keahole power plant site (which were put into limited commercial operation in May and June 2004) and a power purchase agreement (PPA) with Hamakua Energy Partners, L.P. (HEP) for a 60 MW (net) facility (which was completed in December 2000). HELCO has deferred the retirements of some of its older generating units until the 2030 timeframe, and periodically assesses the cost-effectiveness of the continued operation of those units. HELCO’s current plans are to install an 18 MW heat recovery steam generator (ST-7) in 2009 or earlier. After the installation of ST-7, the target date in HELCO’s updated second IRP for the next firm capacity addition is the 2020 timeframe.

HELCO was to have filed its third IRP with the PUC by December 29, 2006, but requested an extension of the filing date to no later than May 31, 2007 and is awaiting a ruling on this request.

MECO’s IRP. MECO filed its second IRP with the PUC in May 2000, and updated it in 2004 and 2005. On the supply side, MECO’s second IRP focused on the planning for the installation of approximately 150 MW of additional generation through the year 2020 on the island of Maui, including 38 MW of generation at its Maalaea power plant site in increments from 2000-2005, 100 MW at its new Waena site in increments from 2007-2018, beginning with a 20 MW combustion turbine in 2007 (currently not planned to be added until 2011), and 10 MW from the acquisition of a wind resource in 2003 (MECO actually first began to purchase wind energy in 2006 from Kaheawa Wind Power, LLC of 30 MW, not 10 MW). Approximately 4 MW of additional generation through the year 2020 were included for each of the islands of Lanai and Molokai. MECO completed the installation of a 20 MW increment (the second) at Maalaea in September 2000, and the final increment of 18 MW, which was originally expected to be installed in 2005, went into commercial operation in October 2006.

MECO’s third IRP is required to be filed with the PUC by April 30, 2007.

HECO’s 2009 Campbell Industrial Park generating unit. In June 2005, HECO filed with the PUC an application for approval of funds to build a new 110 MW simple cycle combustion turbine (CT) generating unit at Campbell Industrial Park and an additional 138 kilovolt transmission line to transmit power from generating units at Campbell Industrial Park (including the new unit) to the rest of the Oahu electric grid (collectively, the Project). Plans are for the combustion turbine to be run primarily as a “peaking” unit beginning in 2009, fueled by biofuels, but with the capability of using diesel or naphtha. On December 15, 2005, HECO signed a contract with Siemens to purchase a 110 MW combustion turbine unit. The contract allows HECO to terminate the contract at a specified payment amount if necessary CT project approvals are not obtained.

The PUC granted an environmental group's motion to intervene. In July 2006, the Honolulu City Council adopted a resolution to amend the Public Infrastructure Map to include the new generating facility at Campbell Industrial Park. HECO's Final Environmental Impact Statement for the Project was accepted by the Department of Planning & Permitting of the City and County of Honolulu in August 2006. In December 2006, HECO filed with the PUC an agreement with the Consumer Advocate in which HECO committed to use 100% biofuels in its new plant and the steps necessary for HECO to reach that goal. After agreeing to use 100% biofuels in its new plant, there were no remaining differences between HECO and the Consumer Advocate regarding the issues in the docket. The environmental group agreed that there is a need for additional generation on Oahu, but disagreed on the use of the proposed CT unit and the use of biofuels. Hearings were held in December 2006. Opening and Reply Briefs are due in March 2007 and a PUC decision is expected to follow.

Preliminary costs for the Project are estimated at $138 million. As of December 31, 2006, accumulated Project costs for planning, engineering, permitting and AFUDC amounted to $4.2 million.

In conjunction with the Project, in December 2006, HECO issued a Request for Proposals for suppliers of ethanol or biodiesel meeting HECO's specifications for the new unit. The PUC would need to approve any resulting ethanol or biodiesel fuel supply contract.

In a related application filed with the PUC in June 2005, HECO requested approval for part of the package of community benefit measures, which is currently estimated at $13.8 million (through the first 10 years of implementation), to mitigate the impact of the new generating unit on communities near the proposed generating unit site. These measures include a base electric rate discount for HECO's residential customers who live near the proposed generation site, additional air quality monitoring stations, a fish monitoring program and the use of recycled instead of potable water for industrial water consumption at the Kahe power plant. For the community benefits application, the only party to the proceeding is the Consumer Advocate, and a hearing was held in November 2006. The primary issue during the hearing was whether rate recovery of foregone revenues from the proposed electric rate discount program is just and reasonable. The Consumer Advocate did not object to the remainder of the community benefit package. Briefs were filed in January 2007 and a PUC decision is pending.

Adequacy of supply.

HECO. HECO's 2007 Adequacy of Supply (AOS) letter, filed in February 2007, indicates that HECO's analysis estimates the reserve capacity shortfall to be approximately 70 MW in the 2007 to 2008 period (before the addition of the Campbell Industrial Park combustion turbine estimated to be installed in 2009), which is significantly smaller than the 170 to 180 MW shortfall in the 2007 to 2008 period projected in the 2006 AOS letter. While the decrease in the projected reserve capacity shortfall is due to a combination of factors, the primary factor is the significantly lower sales and peak forecast issued in August 2006 resulting in a reduction in peak demand used in AOS analyses of approximately 90 MW in the 2007 to 2008 period. Among other factors contributing to the reduction is a small improvement in the expectation of overall availability for existing generating units in future years. The small improvement projected in overall generating unit availability is based on the most recent operating experience in 2006 during which there was some improvement over 2005 in unit availability. However, the availability rates for HECO units have generally declined since 2002 and based on this experience, the manner in which the units must be operated when there is a reserve capacity shortfall, and the increasing ages of the units, HECO expects availability rates to remain suppressed in the near-term. Although the availability rates for generating units on Oahu continue to be better than those of comparable units on the U.S. mainland, HECO generating units may continue to be entirely or partially unavailable to serve load during scheduled overhaul periods and other planned maintenance outages, or when they "trip" or are taken out of operation or their output is "de-rated" due to equipment failure or other causes.

To mitigate the projected reserve capacity shortfalls, HECO is continuing to plan and implement mitigation measures, such as installing distributed generators at substations or other sites, implementing additional load management and other demand reduction measures, and pursuing efforts to improve the availability of generating units. HECO will operate at lower than desired reliability levels and take steps to mitigate the reserve capacity shortfall situation until the next generating unit is installed. Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages.

After the planned 2009 addition of the Campbell Industrial Park generating unit, and in recognition of the uncertainty underlying key forecasts, HECO anticipates the potential for continued reserve capacity shortfalls, which could range between 20 MW to 110 MW in the 2009 to 2012 period. Any plan to install additional firm capacity is required to proceed under the guidance of the Competitive Bidding Framework issued by the PUC in December 2006.

HECO's gross peak demand was 1,327 MW in 2004, 1,273 MW in 2005 and 1,315 MW in 2006. The gross peak demand of 1,327 MW in 2004 was 20 MW higher than the projected peak for 2004. Although the gross peak demand in 2005 and 2006 was lower than in 2004, demand for electricity on Oahu is projected to increase. In October 2004, November 2005, January 2006, June 2006 and February 2007, HECO issued public requests that its customers voluntarily conserve electricity as generating units were out for scheduled maintenance or were unexpectedly unavailable. In addition to making the requests, in November 2005, January 2006, June 2006 and February 2007, HECO remotely turned off water heaters for a number of residential customers who participate in its Energy Scout load-control program.

Also, see "Recent outages" below.

HELCO. HELCO's 2007 Adequacy of Supply letter filed in January 2007 indicated that HELCO's generation capacity for the next three years, 2007 through 2009, is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

Also, see "Recent outages" below.

MECO. In December 2005, MECO's Maalaea Unit 13, a diesel generator, suffered an equipment failure and the unit is not expected to be available for service until approximately July 2007. In February 2007, MECO filed its 2007 Adequacy of Supply letter, which indicated that MECO's Maui island system should usually have sufficient installed capacity to meet the forecasted loads. However, in the event of an unexpected outage of the largest unit, the Maui island system may not have sufficient capacity until Maalaea Unit 13, with a 12.34 MW capacity, returns to service. To overcome insufficient reserve capacity situations, MECO has been implementing appropriate mitigation measures, such as optimizing its unit overhaul schedule to minimize load capability shortfalls, coordinating the delivery of supplemental power, as needed, from an IPP and modifying its combined-cycle unit overhaul procedure to allow for the possible operation of the combustion turbine in simple-cycle mode. In October 2006, MECO placed into commercial operation an additional 18 MW of capacity at its Maalaea power plant site.

In April and August 2006, MECO experienced lower than normal generation capacity due to the unexpected temporary loss of several of its generating units, and issued a public request that its customers voluntarily conserve electricity.

Also, see "Recent outages" below.

Recent outages. HECO's system peak loads generally occur in the fourth quarter of the year, but generation shortfall events may occur at any time during the year.

On June 1, 2006, due to the unanticipated loss of three generating units from an IPP and two HECO generating units, HECO shed power to 29,300 customers in various parts of the island. Power was restored to all customers within four hours.

On Sunday, October 15, 2006, shortly after 7 a.m., two earthquakes centered on the island of Hawaii with magnitudes of 6.7 and 6.0 triggered power outages throughout most of the state and disrupted air traffic on all major islands.

On Oahu, following the impact of the earthquakes, a series of protective actions and automatic systems operated to successively shut down all generators to protect them from potential damage. As a result, no significant damage to any of HECO's generators, or transmission and distribution systems, occurred.

Following the island-wide outage, HECO restored power to customers in a careful, methodical manner to further protect its system, and as a result power was restored to over 99% of its customers over a period of time ranging from approximately 4½ to 18 hours. Management believes the shutdown and methodical restoration of power were necessary to prevent severe damage to HECO's generating equipment and power grid and to avoid a more prolonged blackout.

HELCO's and MECO's smaller electric systems also experienced sustained outages from the earthquakes; however, their systems were for the most part back online by mid to late afternoon.

As is the electric utilities' practice with all major system emergencies, management immediately committed to investigating the outage, including bringing in an outside industry expert to help identify any potential improvements to procedures or systems, and also made arrangements for a preliminary briefing of the PUC. The PUC briefings took place on October 19 and 20, 2006. HECO also conducted a public briefing on October 23, 2006. HECO has made it clear that in addition to any investigation it undertakes, it will cooperate fully with any other reviews conducted by its regulators.

Following requests by members of a state Senate energy subcommittee and the Consumer Advocate that the PUC investigate the power failure, to which investigation HECO stated it did not object, the PUC issued an order on October 27, 2006 opening an investigative proceeding on the outages at HECO, HELCO and MECO on October 15 and 16, 2006. The preliminary questions the PUC has asked to be addressed in the proceeding include (1) aside from the earthquake, are there any underlying causes that contributed or may have contributed to the power outages, (2) were the actions of the electric utilities prior to and during the power outages reasonable and in the public interest, and were the power restoration processes and communication regarding the outages reasonable and timely under the circumstances, (3) could the island-wide power outages on Oahu and Maui have been avoided, and what are the necessary steps to minimize and improve the response to such occurrences in the future, and (4) what penalties, if any, should be imposed on the electric utilities. Pursuant to the PUC's order, HECO's 2006 Outage Report was filed in December 2006, and the outage reports of HELCO and MECO must be filed by March 30, 2007. The investigation consultants retained by HECO, POWER Engineers, Inc., concluded that, "HECO's performance prior to and during the outage demonstrated reasonable actions in the public interest" in a "distinctly extraordinary event." The consultants also made a number of recommendations, mostly of a technical nature, regarding the operation of the electric system during such an incident. Management cannot predict the outcome of the investigation or its impacts on the utilities. Management is currently evaluating additional impacts the earthquakes and outages had and may have on the utilities (e.g., property damage and claims).

Collective bargaining agreements

Each of the electric utilities entered into a four-year collective bargaining agreement in 2003 with the union which represents approximately 58% of electric utility employees. See "Collective bargaining agreements" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

Legislation and regulation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers.

<u>Energy Policy Act of 2005</u>. On August 8, 2005, the President signed into law the Energy Policy Act of 2005 (the Act). The Act provides $14.5 billion in tax incentives over a 10-year period designed to boost conservation efforts, increase domestic energy production and expand the use of alternative energy sources, such as solar, wind, ethanol, biomass, hydropower and clean coal technology. Ocean energy sources, including wave power, are identified as renewable technologies. Section 355 of the Act authorizes a study by the U.S. Department of Energy of Hawaii's dependence on oil; however, that provision is subject to appropriation, as is $9 million authorized under Section 208 for a sugar cane ethanol program in Hawaii. Incentives also include tax credits and shorter depreciable lives for many assets associated with energy production and transmission. The Act's primary direct impact on HECO and its subsidiaries is currently expected to be the reduction in the depreciable tax life, from 20 years to 15 years, of certain electric transmission equipment placed into service after April 11, 2005.

Public Utility Holding Company Act of 1935 (1935 Act) and Public Utility Holding Company Act of 2005 (2005 Act). The repeal of the 1935 Act, effective February 8, 2006, eliminates significant federal restrictions on the scope, structure and ownership of electric utilities. Some believe that the repeal will result in increased institutional ownership of and private equity and hedge fund investments in public utilities, increased consolidation in the industry, more Federal Energy Regulatory Commission (FERC) oversight, and additional diversification by electric utilities. The increased oversight by FERC results in part from the adoption of the 2005 Act, which provides for FERC access to the books and records of utility holding companies and, absent exemptions or waivers, imposes certain record retention and accounting requirements on public utility holding companies. HEI and HECO filed a notification claiming a waiver of such requirements as single-state public utility holding companies. A written notice dated May 26, 2006 was received from FERC confirming the effectiveness of the HEI and HECO waivers. Regulation and oversight of HECO and its subsidiaries by the PUC, however, remains unchanged.

Renewable Portfolio Standard. The 2004 Hawaii Legislature amended an existing renewable portfolio standard (RPS) law to require electric utilities to meet a renewable portfolio standard of 8% of KWH sales by December 31, 2005, 10% by December 31, 2010, 15% by December 31, 2015, and 20% by December 31, 2020. These standards may be met by the electric utilities on an aggregated basis and were met in 2005 when they attained a RPS of 11.7%. It may be difficult, however, for the electric utilities to attain the required renewables percentages in the future, and management cannot predict the future consequences of failure to do so (including potential penalties to be established by the PUC).

The RPS law was further amended in 2006 to provide that at least 50% of the RPS targets must be met by electrical energy generated using renewable energy sources, such as wind or solar, versus from the electrical energy savings from renewable energy displacement technologies (such as solar water heating) or from energy efficiency and conservation programs. The amendment also added provisions for penalties to be established by the PUC if the RPS requirements are not met and criteria for waiver of the penalties by the PUC, if the requirements cannot be met due to circumstances beyond the electric utility's control.

The PUC must, by December 31, 2007, develop and implement a utility ratemaking structure, which may include, but is not limited to, performance-based ratemaking (PBR), to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the RPS, while allowing for deviation from the standards in the event that the standards cannot be met in a cost-effective manner, or as a result of circumstances beyond the control of the utility which could not have been reasonably anticipated or ameliorated.

On January 11, 2007, the PUC opened a new docket (RPS Docket) to examine Hawaii's amended RPS law, to establish the appropriate penalties and to determine circumstances under which penalties should be levied. The PUC indicated that the 2006 amendment to the RPS law that added provisions for penalties effectively gives utilities incentive to comply with RPS and therefore the PUC will no longer complete the rulemaking in a process initiated in November 2004, but will instead proceed by way of this RPS Docket to handle any issues related to the utilities meeting renewable portfolio standards. Management cannot predict the outcome of this process.

See "Renewable energy strategy" below.

Net energy metering. Hawaii has a net energy metering law, which requires that electric utilities offer net energy metering to eligible customer generators (i.e., a customer generator may be a net user or supplier of energy and will make payment to or receive credit from the electric utility accordingly). The law provides a cap of 0.5% of the electric utility's peak demand on the total generating capacity produced by eligible customer-generators. The 2004 Legislature amended the net energy metering law by expanding the definition of "eligible customer generator" to include government entities, increasing the maximum size of eligible net metered systems from 10 kilowatts (kw) to 50 kw and limiting exemptions from additional requirements for systems meeting safety and performance standards to systems of 10 kw or less.

In 2005, the Legislature again amended the net energy metering law by, among other revisions, authorizing the PUC, by rule or order, to increase the maximum size of the eligible net metered systems and to increase the total rated generating capacity available for net energy metering. In April 2006, the PUC initiated an investigative proceeding on whether the PUC should increase (1) the maximum capacity of eligible customer-generators to more than 50 kw and (2) the total rated generating capacity produced by eligible customer-generators to an amount above 0.5% of an electric utility's system peak demand. The parties to the proceeding include HECO, HELCO, MECO, Kauai Island Utility Cooperative, a renewable energy organization and a solar vendor organization. The PUC has approved a procedural schedule with panel hearings scheduled for October 2007. Depending on their magnitude, changes made by the PUC by rule or order could have a negative effect on electric utility sales. Management cannot predict the outcome of the investigative proceeding.

DSM programs. In 2006, the PUC was given the authority, if it deems appropriate, to redirect all or a portion of the funds currently collected by the utilities and included in their revenues through the current utility DSM surcharge into a Public Benefits Fund, for the purpose of supporting customer DSM programs approved by the PUC. If the fund is established, the PUC is required to appoint a fund administrator (other than an electric utility or utility affiliate) to operate and manage the programs established under the fund.

Non-fossil fuel purchased power contracts. In connection with the PUC's determination of just and reasonable rates in purchased power contracts, the PUC will be required to establish a methodology that removes or significantly reduces any linkage between the price paid for non-fossil-fuel-generated electricity under future power purchase contracts and the price of fossil fuel, in order to allow utility customers to receive the potential cost savings from non-fossil fuel generation.

Other legislation. A number of bills were introduced in the 2007 Hawaii State legislative session. The majority of the measures contained in these bills do not negatively affect the electric utilities, and the electric utilities support many of the measures that would encourage the more efficient use of energy and the use of Hawaii's renewable resources. Various bills also propose different approaches to addressing the issue of global warming. At this time, it is not possible to predict the outcome of the deliberations on any proposed legislation.

For a discussion of environmental legislation and regulations, see "Certain factors that may affect future results and financial condition—Consolidated—Environmental matters" below.

Other developments

Advanced Meter Infrastructure (AMI). HECO is evaluating the feasibility of utility applications using power line and wireless technologies for two-way communication.

HECO is currently partnering with Sensus Metering Systems to field test an Advanced Metering Infrastructure system that delivers hourly meter reads, which can enable time-of-use pricing options for HECO customers. This pilot is expected to include more than 3,000 residential, commercial and industrial customers. Other utility applications being evaluated include distribution system line monitoring, residential direct load control and monitoring of distribution substation equipment.

EarthLink, an internet service-provider, has partnered with the City and County of Honolulu in a pilot agreement to test providing free, wireless, broadband access in Chinatown in downtown Honolulu. As part of that Chinatown Pilot project, HECO hopes to negotiate a separate non-binding collaborative agreement with Earthlink to develop and demonstrate a variety of utility applications using WiFi technology, including advanced electric metering and energy conservation initiatives.

In October 2004, the Federal Communications Commission (FCC) released a Report and Order that amended and adopted new rules for Access Broadband over Power Line systems (Access BPL) and stated that an FCC goal in developing the rules for Access BPL "are therefore to provide a framework that will both facilitate the rapid introduction and development of BPL systems and protect licensed radio services from harmful interference."

Currently, there are no PUC regulations for electric utility applications of BPL systems. HECO completed a small-scale trial of the "Broadband over Power Line" (BPL) technology in 2005. Based on the favorable results of the trial, HECO proceeded with a small-scale pilot in an expanded residential/commercial area in Honolulu, which ended in late 2006. That effort was primarily focused on automatic meter reading, which is aimed at enabling time-of-use rates for residential and commercial customers. No further BPL pilots are anticipated at this time.

Renewable energy strategy. The electric utilities continue to pursue the following three-pronged renewable energy strategy: a) promote the development of cost-effective, commercially viable renewable energy projects, b) facilitate the integration of intermittent renewable energy resources and c) encourage renewable energy research, development and demonstration projects (e.g., photovoltaic energy and the electronic shock absorber (ESA) for wind generation). They are also conducting integrated resource planning to evaluate the increased use of renewables within the electric utilities' service territories.

The electric utilities support renewable energy through their solar water heating and heat pump programs and the negotiation and execution of purchased power contracts with nonutility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric and wind turbine generating systems).

HECO received a U.S. patent in February 2005 for an ESA that addresses power fluctuations from wind resources. An ESA demonstration system was installed and tested at HELCO's Lalamilo wind farm. HECO has an intellectual property license agreement with S&C Electric Company (S&C), the party constructing the ESA demonstration system. S&C has the right to seek international patents for the design. On October 16, 2006, the ESA demonstration system sustained structural and fire damage and is no longer operational. However, the impact of the loss on the electric utilities' financial statements is immaterial. In addition, the demonstration confirmed the viability of the technology on a small-scale wind farm, and management plans to pursue a larger scale project in the future. Management cannot predict the amount of royalties HECO may receive from the sale of ESAs in the future.

In December 2002, HECO formed an unregulated subsidiary, RHI, with initial approval to invest up to $10 million in selected renewable energy projects. RHI is seeking to stimulate renewable energy initiatives by prospecting for new projects and sites and taking a passive, minority interest in third party renewable energy projects greater than 1 MW in Hawaii. Since 2003, RHI has periodically solicited competitive proposals for investment opportunities in qualified projects. To date, RHI has signed a Conditional Investment Agreement for a small-scale landfill gas-to-energy project on Oahu, a Framework Agreement for evaluation of three wind projects and two pumped storage hydroelectric projects and two Project Agreements providing the option to invest in wind projects. Project investments by RHI will generally be made only after developers secure the necessary approvals and permits and independently execute a PPA with HECO, HELCO or MECO, approved by the PUC.

In February 2007, BlueEarth Biofuels LLC (BlueEarth) announced plans for a new biodiesel refining plant to be built on the island of Maui by 2009. The biodiesel plant will be owned by BlueEarth Maui Biofuels LLC (BlueEarth Maui), a planned new venture between BlueEarth and a to-be-formed non-regulated subsidiary of HECO. All of the HECO non-regulated subsidiary's profits from the project will be directed into a biofuels public trust to be created for the purpose of funding biofuels development in Hawaii. MECO intends to lease to the non-regulated subsidiary of HECO a portion of the land owned by MECO for its future Waena generation station as the site for the biodiesel plant, with lease proceeds to be credited to MECO ratepayers. In addition, MECO plans to negotiate a fuel purchase contract with BlueEarth Maui for biodiesel to be used in existing diesel-fired units at MECO's Maalaea plant. Both the lease agreement and biodiesel fuel contract will require PUC approval.

Liquidity and capital resources

HECO's consolidated capital structure was as follows:

December 31	2006		2005	
(dollars in millions)				
Short-term borrowings	$ 113	6%	$ 136	7%
Long-term debt, net	766	41	766	38
Preferred stock	34	2	34	2
Common stock equity [1]	959	51	1,039	53
	$1,872	100%	$1,975	100%

[1] Includes AOCI charge for retirement benefit plans in accordance with SFAS No. 158 as of December 31, 2006.

As of February 28, 2007, the Standard & Poor's (S&P) and Moody's Investors Service's (Moody's) ratings of HECO securities were as follows:

	S&P	Moody's
Commercial paper	A-2	P-2
Revenue bonds (senior unsecured, insured)	AAA	Aaa
HECO-obligated preferred securities of trust subsidiary	BBB-	Baa2
Cumulative preferred stock (selected series)	Not rated	Baa3

The above ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating. HECO's overall S&P corporate credit rating is BBB+/Negative/A-2.

The rating agencies use a combination of qualitative measures (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HECO securities. In November 2006, S&P confirmed its corporate credit ratings of HECO and maintained its negative outlook. S&P's ratings outlook "assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years)." S&P indicated:

> Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaiian economy, a punitive final rate order, . . . could lead to lower ratings. Conversely, credit-supportive actions by the company as well as responsive rate treatment would lead to ratings stability.

In addition, S&P ranks business profiles from "1" (strong) to "10" (weak). In November 2006, S&P did not change HECO's business profile rank of "5."

In December 2006, Moody's confirmed its issuer ratings and stable outlook for HECO. 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."

HECO utilizes short-term debt, principally commercial paper, to support normal operations and for other temporary requirements. HECO also periodically borrows short-term from HEI for itself and on behalf of HELCO and MECO, and HECO may borrow from or loan to HELCO and MECO short-term. The intercompany borrowings among the utilities, but not the borrowings from HEI, are eliminated in the consolidation of HECO's financial statements. At December 31, 2006, HELCO and MECO had $49 million and $5 million, respectively, of short-term borrowings from HECO. HECO had an average outstanding balance of commercial paper for 2006 of $136 million and had $113 million of commercial paper outstanding as of December 31, 2006. Management believes that if HECO's commercial paper ratings were to be downgraded, it may be more difficult for HECO to sell commercial paper under current market conditions.

Effective April 3, 2006, HECO entered into a revolving unsecured credit agreement establishing a line of credit facility of $175 million with a syndicate of eight financial institutions. The agreement has an initial term which expires on March 29, 2007. On August 30, 2006, HECO filed an application with the PUC requesting approval to maintain the $175 million credit facility for five years, which, if approved by the PUC, will automatically extend the termination date of the credit facility from March 29, 2007 to March 31, 2011. See Note 6 of HEI's "Notes to Consolidated Financial Statements" for a description of the $175 million credit facility. As of December 31, 2006, the line was undrawn. In the future, the electric utilities may seek to enter into new lines of credit and may also seek to increase the amount of credit available under such lines as management deems appropriate.

Operating activities provided $228 million in net cash during 2006. Investing activities used net cash of $175 million, primarily for capital expenditures, net of contributions in aid of construction. Financing activities used net cash of $49 million, including a $23 million net decrease in short-term borrowings and $30 million for the payment of common and preferred stock dividends. In order to strengthen HECO's balance sheet and support its investment in its reliability program, HECO did not pay any dividends to HEI in the second half of 2006.

In May 2005, the Hawaii legislature authorized the issuance, prior to June 30, 2010, of up to $160 million of Special Purpose Revenue Bonds (SPRBs) ($100 million for HECO, $40 million for HELCO and $20 million for MECO), subject to PUC approval of the projects to be financed, to finance the electric utilities' capital improvement projects. The PUC must approve issuances of long-term securities for HECO, HELCO and MECO, including notes or debentures issued by the electric utilities in connection with the issuance of SPRBs, taxable unsecured notes or trust preferred securities.

In December 2005, an application was filed with the PUC requesting approval to issue up to a total of $165 million in taxable unsecured notes for HECO, MECO and HELCO (up to $100 million for HECO, up to $50 million for HELCO and up to $15 million for MECO). On January 20, 2006, a Registration Statement on Form S-3 was filed with the SEC for unsecured taxable notes to be issued by each of the electric utilities. However, on October 27, 2006, the electric utilities amended the PUC application, in accordance with a stipulation between the utilities and the Consumer Advocate, to seek approval for the issuance of up to $160 million of SPRBs (allocated as indicated above) instead of issuing the taxable unsecured notes. Accordingly, the electric utilities have withdrawn the Registration Statement on Form S-3 and currently contemplate issuing up to $160 million of SPRBs in March 2007.

In September 2006, the electric utilities filed an application with the PUC seeking authority to participate with the Department of Budget and Finance of the State of Hawaii in the issuance of refunding SPRBs, with the proceeds of such bonds, if issued, to be used to redeem the 6.20% Series 1996A SPRBs and/or the 5-7/8% Series 1996B SPRBs, which are currently callable. In December 2006, the PUC granted the approvals necessary to issue the refunding bonds. The decision whether and, if so, when to issue refunding SPRBs and/or to call the Series 1996A and/or the Series 1996B SPRBs will depend on future market conditions and contractual and other considerations.

For the five-year period 2007 through 2011, the utility forecasts $1.2 billion of gross capital expenditures, approximately 51% of which is for transmission and distribution projects and 41% for generation projects, with the remaining 8% for general plant and other projects. These estimates do not include expenditures, which could be material, that would be required to comply with cooling water intake structure regulations adopted by the EPA in 2004 or the July 1999 Regional Haze Rule amendments. See "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements." The electric utilities' net capital expenditures (which exclude AFUDC and capital expenditures funded by third-party contributions in aid of construction) for 2007 through 2011 are currently estimated to total approximately $1.0 billion. HECO's consolidated cash flows from operating activities (net income, adjusted for non-cash income and expense items such as depreciation, amortization and deferred taxes), after the payment of common stock and preferred stock dividends, are currently not expected to provide sufficient cash to cover the forecast net capital expenditures and to reduce the level of short-term borrowings, which level is expected to fluctuate during this forecast period. Long-term debt financing is expected to be required to fund this estimated shortfall as well as any unanticipated expenditures not included in the 2007 through 2011 forecast, such as increases in the costs of, or acceleration of, the construction of capital projects, capital expenditures that may be required by new environmental laws and regulations, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements and higher tax payments that would result if tax positions taken by the utilities do not prevail.

Proceeds from the anticipated issuance of revenue bonds, cash flows from operating activities and temporary increases in short-term borrowings are expected to provide the forecast $199 million needed for the net capital expenditures in 2007. For 2007, gross capital expenditures are estimated to be $232 million, including approximately $130 million for transmission and distribution projects, approximately $77 million for generation projects and approximately $25 million for general plant and other projects. Consolidated net capital expenditures for HECO and subsidiaries for 2006, 2005 and 2004 were $171 million, $194 million and $187 million, respectively.

Funding for the electric utilities' qualified pension plans is based upon actuarially determined contributions that consider the amount deductible for income tax purposes and the funding requirements under the Employee Retirement Income Security Act of 1974, as amended (ERISA). Although the electric utilities were not required to make any contributions to the qualified pension plans to meet minimum funding requirements pursuant to ERISA for 2006, 2005 and 2004, they made voluntary contributions in 2005 and 2004. With respect to the postretirement benefit plans, the electric utilities policy is to comply with directives from the PUC to fund the costs. Contributions by the electric utilities to the retirement benefit plans for 2006, 2005 and 2004 totaled $10 million, $18 million and $34 million, respectively, and are expected to total $11 million in 2007. Additional contributions to the retirement benefit plans may be required, or may be made even if not required, and such contributions could be in amounts substantially in excess of the amounts currently included in the electric utilities forecast of their consolidated financing requirements for the period 2007 through 2011. SFAS No. 158, which was adopted on December 31, 2006, does not impact the calculations of retirement benefit costs.

Management periodically reviews capital expenditure estimates and the timing of construction projects. These estimates may change significantly as a result of many considerations, including changes in economic conditions, changes in forecasts of KWH sales and peak load, the availability of purchased power and changes in expectations concerning the construction and ownership of future generating units, the availability of generating sites and transmission and distribution corridors, the ability to obtain adequate and timely rate increases, escalation in construction costs, the impacts of DSM programs and combined heat and power installations, the effects of opposition to proposed construction projects and requirements of environmental and other regulatory and permitting authorities.

Bank

Executive overview and strategy

When ASB was acquired by HEI in 1988, it was a traditional thrift with assets of $1 billion and net income of about $13 million. ASB has grown by both acquisition and internal growth since 1988 and ended 2006 with assets of $6.8 billion and net income of $56 million, compared to assets of $6.8 billion as of December 31, 2005 and net income of $65 million in 2005.

The interest rate environment, the quality of ASB's assets, and the strategic transformation of ASB from a traditional thrift to a community bank have impacted and will continue to impact its financial results.

ASB has been facing a challenging interest rate environment that has pressured its net interest margin. The Federal Reserve Bank's rate increases since mid-2004 have led to higher short-term interest rates, while, during the same period, long-term interest rates have remained low, resulting in an inverted yield curve throughout the second half of 2006. The higher short-term interest rates have put upward pressure on deposit rates, while the low long-term interest rates have held down asset yields, putting downward pressure on net interest margin. If the current interest rate environment persists, the potential for compression of ASB's margin will continue to be a concern. As part of its interest rate risk management process, ASB uses simulation analysis to measure net interest income sensitivity to changes in interest rates (see "Quantitative and Qualitative Disclosures about Market Risk"). ASB then employs strategies to limit the impact of changes in interest rates on net interest income. ASB's key strategies include:

(1) attracting and retaining low cost deposits, which enables ASB to replace other borrowings and reduce funding costs;
(2) diversifying its loan portfolio with higher-yielding, shorter-maturity loans or variable rate loans such as commercial, commercial real estate and consumer loans, which also creates a more diversified income stream for the bank;
(3) investing in mortgage-related securities with short average lives; and
(4) managing costing liabilities to optimize cost of funds and manage interest rate sensitivity.

ASB's asset quality remained strong in 2006 as a result of continued strength in the Hawaii economy and the real estate market. However, ASB recorded a provision for loan losses of $0.8 million after-tax during 2006, primarily due to a single commercial loan, compared to a $1.9 million after-tax reversal of allowance for loan losses during 2005. ASB's allowance as a percentage of average loans was 0.85% at the end of 2006, compared to 0.90% and 1.08% at the end of 2005 and 2004, respectively. This ratio falls between the benchmark ratios for national banks and thrifts, which is as expected because ASB's large residential mortgage portfolio is typical of a thrift and ASB has added commercial and commercial real estate loans typical of commercial banks. The allowance is adjusted continuously through the provision for loan losses to reflect factors such as charge-offs; outstanding loan balances; loan grading; external factors affecting the national and Hawaii economy, specific industries and sectors and interest rates; and historical and estimated loan losses.

ASB is a full-service community bank serving both consumer and commercial customers. In order to remain competitive and continue building core franchise value, the bank continues to develop and introduce new products and services in order to meet the needs of those markets. Additionally, the banking industry is constantly changing and ASB is making the investments in people and technology necessary to adapt and remain competitive. ASB's ongoing challenge is to increase revenues faster than expenses.

Results of Operations

(dollars in millions)	2006	% change	2005	% change	2004
Revenues	$ 408	5	$ 388	6	$ 364
Net interest income	203	(3)	210	8	194
Operating income	89	(16)	105	–	105
Net income	56	(14)	65	58	41
Return on average common equity [1]	10.0%		11.7%		8.0%
Earning assets					
Average balance [2]	$ 6,367	–	$ 6,374	3	$ 6,162
Weighted-average yield	5.48%	6	5.19%	4	4.98%
Costing liabilities					
Average balance [2]	$ 6,154	–	$ 6,157	4	$ 5,934
Weighted-average rate	2.37%	3	1.97%	4	1.90%
Interest rate spread	3.11%	(3)	3.22%	5	3.08%
Net interest margin [3]	3.18%	(3)	3.29%	4	3.15%

1 In late December 2004, ASB's capital structure changed when ASB redeemed its preferred stock held by HEIDI ($75 million) and HEIDI infused common equity into ASB ($75 million). If ASB's reported common equity as of December 31, 2004 was reduced by $75 million for the calculation, ASB's ROACE would have been 8.7% for 2004.
2 Calculated using the average daily balances.
3 Defined as net interest income as a percentage of average earning assets.

Bank franchise taxes (ASB)

The results of operations for 2004 include a net charge of $20 million due to a June 2004 tax ruling and subsequent settlement as discussed in Note 10 of HEI's "Notes to Consolidated Financial Statements" under "ASB state franchise tax dispute and settlement." The following table presents a reconciliation of ASB's net income to net income excluding the $20 million charge in 2004. Management believes the adjusted information below presents ASB's net income on a more comparable basis for the periods shown. However, the 2004 adjusted net income is not a presentation defined under GAAP and may not be comparable to other companies or more useful than the GAAP presentation included in HEI's consolidated financial statements.

Years ended December 31	2006	2005	2004
(dollars in thousands)			
Net income	$55,782	$64,883	$41,062
Cumulative bank franchise taxes, net of taxes, through December 31, 2003	–	–	20,340
Net income – as adjusted	$55,782	$64,883	$61,402
ROACE – as adjusted [1]	10.0%	11.7%	13.3%

[1] Calculated using adjusted net income divided by the simple average adjusted common equity (excluding the $75 million common equity infusion in December 2004 from equity as of December 31, 2004).

Taking into account the adjustments in the table above, ASB's 2005 net income would have increased 6% compared to 2004.

Bank operations

Earnings of ASB depend primarily on net interest income, which is the difference between interest earned on earning assets and interest paid on costing liabilities. As discussed above, if the current interest rate environment persists, compression of ASB's net interest margin will continue to be a concern. ASB's loan volumes and yields are affected by market interest rates, competition, demand for financing, availability of funds and management's responses to these factors. As of December 31, 2006, ASB's loan portfolio mix, net, consisted of 72% residential loans, 12% commercial loans, 9% commercial real estate loans and 7% consumer loans. As of December 31, 2005, ASB's loan portfolio mix, net, consisted of 74% residential loans, 11% commercial loans, 8% commercial real estate loans and 7% consumer loans. ASB's mortgage-related securities portfolio consists primarily of shorter-duration assets and is affected by market interest rates and demand.

Deposits continue to be the largest source of funds for ASB and are affected by market interest rates, competition and management's responses to these factors. Advances from the FHLB of Seattle and securities sold under agreements to repurchase continue to be significant sources of funds, but the amount of advances has trended downward over the last few years. As of December 31, 2006, ASB's costing liabilities consisted of 74% deposits and 26% other borrowings, comparable to December 31, 2005. However, in 2006, higher short-term interest rates and the inverted yield curve made it challenging to retain deposits and control funding costs. ASB experienced net deposit outflows in the middle of 2006, and management acted in response with a combination of tactical repricings of deposits, promotions and the introduction of new products and services. The shift in deposit mix from lower cost savings and checking accounts to higher cost certificates, along with the repricing of deposits, has contributed to increased funding costs. Deposits as of December 31, 2006 were essentially flat compared to deposits as of December 31, 2005. Deposit retention and growth, however, will remain a challenge in the current environment.

Other factors primarily affecting ASB's operating results include fee income, provision (or reversal of allowance) for loan losses, gains or losses on sales of securities available-for-sale and expenses from operations.

Although higher long-term interest rates could reduce the market value of mortgage-related securities and reduce stockholder's equity through a balance sheet charge to AOCI, this reduction in the market value of mortgage-related securities would not result in a charge to net income in the absence of an "other-than-temporary" impairment in the value of the securities. As of December 31, 2006 and 2005, the unrealized losses, net of tax benefits, on available-for-sale investment and mortgage-related securities (including securities pledged for repurchase agreements) in AOCI was $35 million and $36 million, respectively. See “Quantitative and qualitative disclosures about market risk.”

The following table sets forth average balances, interest and dividend income, interest expense and weighted-average yields earned and rates paid, for certain categories of earning assets and costing liabilities for the years indicated. Average balances for each year have been calculated using the daily average balances during the year.

Years ended December 31	2006	2005	2004
(dollars in thousands)			
Loans receivable			
Average balances [1]	$ 3,687,673	$ 3,411,389	$ 3,121,878
Interest income [2]	231,610	205,084	184,773
Weighted-average yield	6.28%	6.01%	5.92%
Investment and mortgage-related securities			
Average balances	$ 2,507,608	$ 2,780,408	$ 2,845,730
Interest income	113,403	122,828	118,424
Weighted-average yield	4.52%	4.42%	4.16%
Other investments [3]			
Average balances	$ 172,146	$ 182,586	$ 194,039
Interest and dividend income	3,757	3,096	3,923
Weighted-average yield	2.18%	1.70%	2.02%
Total earning assets			
Average balances	$ 6,367,427	$ 6,374,383	$ 6,161,647
Interest and dividend income	348,770	331,008	307,120
Weighted-average yield	5.48%	5.19%	4.98%
Deposit liabilities			
Average balances	$ 4,540,292	$ 4,453,762	$ 4,114,070
Interest expense	73,614	52,064	47,184
Weighted-average rate	1.62%	1.17%	1.15%
Borrowings			
Average balances	$ 1,613,667	$ 1,703,353	$ 1,819,598
Interest expense	72,482	69,362	65,603
Weighted-average rate	4.49%	4.07%	3.61%
Total costing liabilities			
Average balances	$ 6,153,959	$ 6,157,115	$ 5,933,668
Interest expense	146,096	121,426	112,787
Weighted-average rate	2.37%	1.97%	1.90%
Net average balance	$ 213,468	$ 217,268	$ 227,979
Net interest income	202,674	209,582	194,333
Interest rate spread	3.11%	3.22%	3.08%
Net interest margin [4]	3.18%	3.29%	3.15%

1 Includes nonaccrual loans.
2 Includes loan fees of $5.3 million, $6.4 million and $6.1 million for 2006, 2005 and 2004, respectively, together with interest accrued prior to suspension of interest accrual on nonaccrual loans.
3 Includes stock in the FHLB of Seattle ($98 million as of December 31, 2006). ASB received dividends of $98,000 in 2006, $0.4 million in 2005 and $2.7 million in 2004. See “FHLB of Seattle business and capital plan” below.
4 Defined as net interest income as a percentage of average earning assets.

- Net interest income before provision for loan losses for 2006 decreased by $7 million, or 3.3%, when compared to 2005 as the challenging interest rate environment pressured ASB's net interest margin. Continued growth in average loans and deposits partially offset margin compression pressure from a flattening yield curve, which was inverted throughout the second half of 2006. Net interest margin decreased from 3.29% in 2005 to 3.18% in 2006 as the impact of growth in the loan portfolio and higher yields in the loan and mortgage-related securities portfolios was more than offset by increased funding costs. The increase in the average loan portfolio balance was helped by the continued strength in the Hawaii economy and real estate market. The decrease in the average investment and mortgage-related securities portfolios was due to the use of the proceeds from repayments in the portfolios to fund loans. Increased average deposit balances enabled ASB to replace other borrowings.

ASB's asset quality remained strong due to continued strength in real estate and business conditions, which resulted in low historical loss ratios and low net charge-offs for ASB. However, a provision for loan losses of $1.4 million ($0.8 million, net of tax) was recorded in 2006, primarily due to a single commercial loan, but management does not believe that the adverse development of this loan is reflective of a trend in the overall credit quality of the loan portfolio. This compares with a reversal of allowance for loan losses of $3 million ($2 million, net of tax) in 2005.

Noninterest income for 2006 increased by $2.7 million over 2005 due to higher fee income on deposit liabilities and gains on sales of securities, partially offset by lower income from the sale of investment and insurance products.

Noninterest expense for 2006 increased by $7.6 million over 2005 primarily due to higher legal and litigation-related expenses and occupancy expenses.

- Net interest income before reversal of allowance for loan losses for 2005 increased by $15 million, or 7.8%, when compared to 2004. Strong organic growth in loans and deposits and the ability to keep deposit cost low enabled ASB to offset margin compression pressure from a flattening yield curve, which inverted near year-end. Net interest margin increased from 3.15% in 2004 to 3.29% in 2005 due to growth in the loan portfolio and higher yields in the loan and mortgage-related securities portfolios funded by strong deposit growth. The increase in the average loan portfolio balance was due in part to the continued strength in the Hawaii economy and real estate market. The decrease in the average investment and mortgage-related securities portfolios was due to the reinvestment of excess liquidity into loans. Average deposit balances grew by $340 million, enabling ASB to replace other borrowings and helping fund loan growth. The shift in liability mix enabled ASB to keep down its weighted average rate on costing liabilities.

Due to considerable strength in real estate and business conditions, which resulted in lower historical loss ratios and lower net charge-offs for ASB, and other factors discussed above, ASB recorded a reversal of allowance for loan losses of $3 million ($2 million, net of tax) in 2005, which was less than the reversal of allowance for loan losses of $8 million ($5 million, net of tax) in 2004.

Noninterest income remained stable for 2005 when compared to 2004.

Noninterest expense for 2005 increased by $10 million, or 6.3%, over 2004, primarily due to higher compensation and employee benefits expense related to strategic initiatives, increased pension costs, Sarbanes-Oxley Act of 2002 (SOX) compliance costs and the charge for prepayment of a high cost Federal Home Loan Bank advance.

- During 2006, ASB's allowance for loan losses increased by $0.6 million, compared to decreases in its allowance for loan losses during 2005 and 2004 of $3 million and $10 million, respectively.

ASB's nonaccrual and renegotiated loans represented 0.2%, 0.2% and 0.4% of total loans outstanding as of December 31, 2006, 2005 and 2004, respectively. See Note 4 of HEI's "Notes to Consolidated Financial Statements."

FHLB of Seattle business and capital plan

In December 2004, the FHLB of Seattle signed an agreement with its regulator, the Federal Housing Finance Board (Finance Board), to adopt a business and capital plan to strengthen its risk management, capital structure and governance. In April 2005, the FHLB of Seattle delivered a proposed three-year business plan and capital management plan to the Finance Board, and issued a press release stating that it anticipates minimal to no dividends in the next few years while it implements its new business model. No dividends were received by ASB from the FHLB of Seattle during the fourth quarter of 2004, the last three quarters of 2005 and the first three quarters of 2006. In December 2006, the Board of Directors of the FHLB of Seattle declared, and ASB received, a cash dividend of $98,000 in December 2006. In January 2007, the FHLB of Seattle announced that the Finance Board had terminated its agreement with the FHLB of Seattle, attributing the termination to its full compliance with the terms of the agreement and significant progress the FHLB of Seattle has made in implementing its business and capital management plan.

Legislation and regulation

ASB is subject to extensive regulation, principally by the Office of Thrift Supervision (OTS) and the Federal Deposit Insurance Corporation (FDIC). Depending on its level of regulatory capital and other considerations, these regulations could restrict the ability of ASB to compete with other institutions and to pay dividends to its shareholders. See the discussions below under “Liquidity and capital resources” and “Certain factors that may affect future results and financial condition—Bank.”

Liquidity and capital resources

December 31	2006	% change	2005	% change
(dollars in millions)				
Assets	$6,808	–	$6,835	1
Available-for-sale investment and mortgage-related securities	2,367	(10)	2,629	(11)
Investment in stock of Federal Home Loan Bank of Seattle	98	–	98	–
Loans receivable, net	3,780	6	3,567	10
Deposit liabilities	4,576	–	4,557	6
Other bank borrowings	1,569	(3)	1,622	(10)

As of December 31, 2006, ASB was the third largest financial institution in Hawaii based on assets of $6.8 billion and deposits of $4.6 billion.

ASB’s principal sources of liquidity are customer deposits, borrowings, the maturity and repayment of portfolio loans and securities and the sale of loans into secondary market channels. ASB’s deposits as of December 31, 2006 were $18 million higher than December 31, 2005. ASB’s principal sources of borrowings are advances from the FHLB and securities sold under agreements to repurchase from broker/dealers. As of December 31, 2006, FHLB borrowings totaled approximately $0.7 billion, representing 11% of assets. ASB is approved to borrow from the FHLB up to 35% of ASB’s assets to the extent it provides qualifying collateral and holds sufficient FHLB stock. As of December 31, 2006, ASB’s unused FHLB borrowing capacity was approximately $1.7 billion. As of December 31, 2006, securities sold under agreements to repurchase totaled $0.8 billion, representing 12% of assets. ASB utilizes deposits, advances from the FHLB and securities sold under agreements to repurchase to fund maturing and withdrawable deposits, repay maturing borrowings, fund existing and future loans and make investments. As of December 31, 2006, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.1 billion. Management believes ASB’s current sources of funds will enable it to meet these commitments and obligations while maintaining liquidity at satisfactory levels.

As of December 31, 2006 and 2005, ASB had $2.4 million of loans on nonaccrual status, or 0.1% of net loans outstanding. As of December 31, 2006 and 2005, ASB’s real estate acquired in settlement of loans was nil and $0.2 million, respectively.

In 2006, net cash of $34 million was provided by investing activities primarily due to repayments of investment and mortgage-related securities and sales of mortgage-related securities, net of purchases, partly offset by net increases in loans held for investment and capital expenditures. Financing activities used net cash of $84 million due to net decreases in other borrowings and the payment of common stock dividends, partly offset by net increases in deposits. Operating activities provided cash of $94 million.

ASB believes that a satisfactory regulatory capital position provides a basis for public confidence, affords protection to depositors, helps to ensure continued access to capital markets on favorable terms and provides a foundation for growth. FDIC regulations restrict the ability of financial institutions that are not well-capitalized to compete on the same terms as well-capitalized institutions, such as by offering interest rates on deposits that are significantly higher than the rates offered by competing institutions. As of December 31, 2006, ASB was well-capitalized (see "Regulation of ASB" for ASB's capital ratios).

Certain factors that may affect future results and financial condition

The Company's results of operations and financial condition can be affected by numerous factors, many of which are beyond its control and could cause future results of operations to differ materially from historical results. The following is a discussion of certain of these factors. See also "Forward-Looking Statements" above and "Item 1A. Risk Factors."

Consolidated

Economic conditions. Because its core businesses are providing local electric utility and banking services, HEI's operating results are significantly influenced by the strength of Hawaii's economy, which in turn is influenced by economic conditions in the mainland U.S. (particularly California) and Asia (particularly Japan) as a result of the impact of those conditions on tourism. See "Economic conditions" above.

Competition. The electric utility and banking industries are competitive and the Company's success in meeting competition will continue to have a direct impact on the Company's financial performance.

Electric utility. Although competition in the generation sector in Hawaii has been moderated by the scarcity of generation sites, various permitting processes and lack of interconnections to other electric utilities, HECO and its subsidiaries face competition from IPPs and customer self-generation, with or without cogeneration.

In March 2000, the PUC approved a standard form contract for customer retention that allows HELCO to provide a rate option for customers who would otherwise reduce their energy use from HELCO's system by using energy from a nonutility generator. Based on HELCO's current rates, the standard form contract provides a 10% discount on base energy rates for qualifying "Large Power" and "General Service Demand" customers. In November 2006, HELCO entered into three-year standard form contracts with two of its hotel customers.

In 1996, the PUC issued an order instituting a proceeding to identify and examine the issues surrounding electric competition and to determine the impact of competition on the electric utility infrastructure in Hawaii. In October 2003, the PUC closed the competition proceeding and opened investigative proceedings on two specific issues (competitive bidding and DG) to move toward a more competitive electric industry environment under cost-based regulation.

Competitive bidding proceeding. The stated purpose of this proceeding is to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii.

The parties in the proceeding included the Consumer Advocate, HECO, HELCO, MECO, Kauai Island Utility Cooperative (KIUC) and Hawaii Renewable Energy Alliance (HREA), a renewable energy organization. The issues addressed in the proceeding included whether a competitive bidding system should be developed for acquiring or building new generation and, if so, how a fair system can be developed that "ensures that competitive benefits result from the system and ratepayers are not placed at undue risk," what the guidelines and requirements for prospective bidders should be, and how such a system can encourage broad participation.

On June 30, 2006, the PUC issued a decision in this proceeding, which included a proposed framework to govern competitive bidding as a mechanism for acquiring or building new generation in Hawaii. The decision required the parties to submit comments on the proposed framework. On September 11, 2006, HECO, HELCO and MECO, the Consumer Advocate and HREA each submitted comments on the proposed framework and responded to the PURPA issues in the decision. KIUC had no comments on the proposed framework.

On December 8, 2006, the PUC issued a decision which reviewed the parties' comments and revised the competitive bidding framework, which became effective from the issuance of the decision. The framework states, among other things, that: (1) a utility is required to use competitive bidding to acquire a future generation resource or a block of generation resources unless the PUC finds bidding to be unsuitable, (2) the determination on whether to use competitive bidding for a future generation resource or a block of generation resources will be made by the PUC during its review of the utility's IRP, (3) an exemption from the framework is granted for cooperatively-owned utilities, (4) the framework does not apply to two pending projects (HECO's CIP-1 and HELCO's ST-7), MECO's M-18 project (which went into commercial operation in October 2006), specifically identified offers to sell energy on an as-available basis or to sell firm energy and/or capacity by non-fossil fuel producers that were under review by an electric utility at the time this framework was adopted (provided that negotiations with the non-fossil producers are completed no later than December 31, 2007), and certain other situations as identified in the framework, (5) waivers from competitive bidding for certain circumstances will be considered by the PUC and granted when considered appropriate, (6) for each project that is subject to competitive bidding, the utility is required to submit a report on the cost of parallel planning upon the PUC's request, (7) the utility is required to consider the effects on competitive bidding of not allowing bidders access to utility-owned or controlled sites, and to present reasons to the PUC for not allowing site access to bidders when the utility has not chosen to offer a site to a third party, (8) the utility is required to select an independent observer from a list approved by the PUC whenever the utility or its affiliate seeks to advance a project proposal (i.e., in competition with those offered by bidders) in response to a need that is addressed by its Request for Proposal (RFP) or when the PUC otherwise determines, (9) the evaluation of the utility's bid should account for the possibility that the capital or running costs actually incurred, and recovered from ratepayers, over the plant's lifetime, will vary from the levels assumed in the utility's bid, (10) the utility may consider its own self-bid proposals in response to generation needs identified in its RFP, and (11) for any resource to which competitive bidding does not apply (due to waiver or exemption), the utility retains its traditional obligation to offer to purchase capacity and energy from a Qualifying Facility (QF) at avoided cost upon reasonable terms and conditions approved by the PUC. The decision also ordered the utilities to file proposed tariffs containing procedures for interconnection and transmission upgrades within 90 days from the issuance of the framework, and proposed Codes of Conduct within 180 days from the issuance of the framework, or prior to commencement of any competitive bidding process, whichever comes first.

Management cannot currently predict the ultimate effect of this decision on the ability of the electric utilities to acquire or build additional generating capacity in the future.

Distributed generation proceeding. In October 2003, the PUC opened 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 PUC issued its D&O in the DG proceeding. In the D&O, the PUC indicated 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.

With regard to DG ownership, the D&O affirmed the ability of the electric utilities to procure and operate DG for utility purposes at utility sites. The PUC also indicated its desire to promote the development of a competitive market for customer-sited DG. In weighing the general advantages and disadvantages of allowing a utility to provide DG services on a customer's site, the PUC found that the "disadvantages outweigh the advantages." However, the PUC also found that the utility "is the most informed potential provider of DG" and it would not be in the public interest to exclude the electric utilities from providing DG services at this early stage of DG market development.

Therefore, the D&O allows the utility to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need, (2) the DG is the lowest cost alternative to meet that need, and (3) it can be shown that, in an open and competitive process acceptable to the PUC, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility's offering.

On March 1, 2006, the electric utilities filed a Motion for Clarification and/or Partial Reconsideration (DG Motion), requesting that the PUC clarify how the three conditions under which electric utilities are allowed to provide regulated DG services at customer-owned sites will be administered, in order to better determine the impacts the conditions may have on the electric utilities' DG plans. On April 6, 2006, the PUC issued its decision on the electric utilities' Motion and provided clarification to the conditions under which the electric utilities are allowed to provide regulated DG services (e.g., the utilities can use a portfolio perspective—a DG project aggregated with other DG systems and other supply-side and demand-side options—to support a finding that utility-owned customer-sited DG projects fulfill a legitimate system need, and the economic standard of "least cost" in the order means "lowest reasonable cost" consistent with the standard in the IRP framework), and affirmed that the electric utility has the responsibility to demonstrate that it meets all applicable criteria included in the D&O in its application for PUC approval to proceed with a specific DG project.

The electric utilities are currently evaluating several potential DG and combined heat and power (CHP, a form of DG) projects. If a decision is made to pursue a specific project, an application requesting project approval will be filed with the PUC. In July 2006, MECO filed an application for approval of an agreement for the installation of a CHP system on the island of Lanai. On September 11, 2006, the PUC issued a Schedule of Proceedings for its consideration of this CHP project. The Consumer Advocate filed its statement of position in January 2007 and MECO filed its response to the Consumer Advocate's statement of position in February 2007.

Prior to opening of the investigative DG proceeding, in October 2003 the electric utilities filed an application for approval of CHP tariffs, under which they would own, operate and maintain customer-sited, packaged CHP systems (and certain ancillary equipment) pursuant to standard form contracts with eligible commercial customers. This CHP tariff application and a HELCO application for approval of an agreement with a customer for a utility CHP project were suspended by the PUC until, at a minimum, the matters in the DG proceeding were adequately addressed.

By letters dated November 2, 2006, the PUC requested that the utilities state their intentions with regard to pursuing the CHP tariff application and that HELCO state its intentions with regard to its CHP project application, given the PUC criteria for allowing regulated utility-owned DG stated in the DG proceeding D&O. On December 29, 2006, the utilities withdrew their CHP tariff application, based on the determination that it would be difficult to implement CHP projects on a programmatic basis given the criteria of the D&O. The utilities will continue to consider CHP projects on a case-by-case basis, and if a decision is made to pursue the implementation of a CHP project, then an application will be filed requesting PUC approval of such CHP project. On December 29, 2006, HELCO withdrew its CHP project application for a particular customer on the basis that the D&O would require substantial modifications to the application and existing CHP agreement. HELCO is continuing to work with its customer with respect to CHP and/or other energy cost savings alternatives, and if a decision is made to pursue the implementation of a CHP system, then an application will be filed requesting PUC approval of a new CHP agreement.

The D&O also required the electric utilities to file tariffs, establish reliability and safety requirements for DG, establish a non-discriminatory DG interconnection policy, develop a standardized interconnection agreement to streamline the DG application review process, establish standby rates based on unbundled costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services), and establish detailed affiliate requirements should the utility choose to sell DG through an affiliate. The electric utilities filed their proposed modifications to existing DG interconnection tariffs and their proposed unbundled standby rates for PUC approval in the third quarter of 2006. The Consumer Advocate stated that it did not object to implementation of the interconnection and standby rate tariffs at the present time, but reserved the right to review the reasonableness of both tariffs in rate proceedings for each of the utilities. By order dated December 28, 2006, the PUC opened a new proceeding to investigate the utilities' proposed DG interconnection tariff modifications and standby rate tariffs.

Bank. The banking industry in Hawaii is highly competitive. ASB is the third largest financial institution in Hawaii, based on assets, and is in direct competition for deposits and loans, not only with the two larger institutions, but also with smaller institutions that are heavily promoting their services in certain niche areas, such as providing financial services to small- and medium-sized businesses, and national organizations offering financial services. ASB's main competitors are banks, savings associations, credit unions, mortgage brokers, finance companies and securities brokerage firms. These competitors offer a variety of lending, deposit and investment products to retail and business customers.

The primary factors in competing for deposits are interest rates, the quality and range of services offered, marketing, convenience of locations, hours of operation and perceptions of the institution's financial soundness and safety. To meet competition, ASB offers a variety of savings and checking accounts at competitive rates, convenient business hours, convenient branch locations with interbranch deposit and withdrawal privileges at each branch and convenient automated teller machines. ASB also conducts advertising and promotional campaigns.

The primary factors in competing for first mortgage and other loans are interest rates, loan origination fees and the quality and range of lending and other services offered. ASB believes that it is able to compete for such loans primarily through the competitive interest rates and loan fees it charges, the type of mortgage loan programs it offers and the efficiency and quality of the services it provides to individual borrowers and the business community.

ASB is a full-service community bank serving both consumer and commercial customers and has been diversifying its loan portfolio from single-family home mortgages to higher-yielding, shorter-duration consumer, commercial and commercial real estate loans. The origination of consumer, commercial and commercial real estate loans involves risks and other considerations different from those associated with originating residential real estate loans. For example, the sources and level of competition may be different and credit risk is generally higher than for mortgage loans. These different risk factors are considered in the underwriting and pricing standards and in the allowance for loan losses established by ASB for its consumer, commercial and commercial real estate loans.

U.S. capital markets and interest rate environment. Changes in the U.S. capital markets can have significant effects on the Company. For example:

- Volatility in U.S. capital markets can affect the fair values of assets available to satisfy retirement benefits obligations. The Company estimates that consolidated retirement benefits expense, net of amounts capitalized and income taxes, will be $20 million in 2007 as compared to $17 million in 2006, partly as a result of changing the expected long-term rate of return assumption in recognition of lower expected future returns in the capital markets.
- Volatility in U.S. capital markets may negatively impact the fair values of investment and mortgage-related securities held by ASB. As of December 31, 2006, the fair value and carrying value of the investment and mortgage-related securities held by ASB were $2.4 billion.

Interest rate risk is a significant risk of ASB's operations. ASB actively manages this risk, including managing the relationship of its interest-sensitive assets to its interest-sensitive liabilities. The Federal Reserve began increasing rates in 2004, while longer-term interest rates have not increased significantly, causing a flattening of the yield curve. The yield curve was inverted throughout the second half of 2006. This type of interest rate environment typically puts downward pressure on ASB's net interest margin. As of December 31, 2006, the Company had no floating-rate long-term debt outstanding. As of December 31, 2006, consolidated HEI had $176 million of commercial paper outstanding with a weighted-average interest rate of 5.44% and maturities ranging from 2 to 38 days. See "Quantitative and Qualitative Disclosures about Market Risk."

Technological developments. New technological developments (e.g., the commercial development of fuel cells or distributed generation or significant advances in internet banking) may impact the Company's future competitive position, results of operations and financial condition.

Limited insurance. In the ordinary course of business, the Company purchases insurance coverages (e.g., property and liability coverages) to protect itself against loss of or damage to its properties and against claims made by third-parties and employees for property damage or personal injuries. However, the protection provided by such insurance is limited in significant respects and, in some instances, the Company has no coverage. For electric utility examples, see “Limited insurance” in Note 3 of HEI’s “Notes to Consolidated Financial Statements.” ASB also has no insurance coverage for business interruption or credit card fraud. Certain of the Company’s insurance has substantial “deductibles” or has limits on the maximum amounts that may be recovered. Insurers also have exclusions or limitations of coverage for claims related to certain perils including, but not limited to, mold and terrorism. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, the Company could incur uninsured losses in amounts that would have a material adverse effect on the Company’s results of operations and financial condition.

Environmental matters. HEI and its subsidiaries are subject to environmental laws and regulations that regulate the operation of existing facilities, the construction and operation of new facilities and the proper cleanup and disposal of hazardous waste and toxic substances. These laws and regulations, among other things, require that certain environmental permits be obtained as a condition to constructing or operating certain facilities. Obtaining such permits can entail significant expense and cause substantial construction delays. Also, these laws and regulations may be amended from time to time, including amendments that increase the burden and expense of compliance. Management believes that the recovery through rates of most, if not all, of any costs incurred by HECO and its subsidiaries in complying with environmental requirements would be allowed by the PUC.

The HECO, HELCO and MECO generating stations operate under air pollution control permits issued by the DOH and, in a limited number of cases, by the EPA. The 2004 legislature passed legislation that clarifies that the accepting agency or authority for an environmental impact statement is not required to be the approving agency for the permit or approval and also requires an environmental assessment for proposed waste-to-energy facilities, landfills, oil refineries, power-generating facilities greater than 5 MW and wastewater facilities, except individual wastewater systems. This legislation could result in an increase in project costs.

The entire electric utility industry has been affected by the 1990 amendments to the Clean Air Act (CAA), changes to the National Ambient Air Quality Standard (NAAQS) for ozone, and adoption of a NAAQS for fine particulate matter. Further significant impacts may occur if currently proposed legislation, rules and standards are adopted (e.g., greenhouse gas emission reduction rules) or are deemed applicable to company facilities (e.g., Regional Haze Rule amendments).

Pending environmental matters that may adversely affect the Company’s future operating results and financial condition include the ongoing Honolulu Harbor environmental investigation, the July 1999 Regional Haze Rule amendments and section 316(b) of the federal Clean Water Act, which are discussed under “Environmental regulation” in Note 3 of HEI’s “Notes to Consolidated Financial Statements.” There can be no assurance that a significant environmental liability will not be incurred by the electric utilities or that the related costs will be recoverable through rates.

Prior to extending a loan secured by real property, ASB conducts due diligence to assess whether or not the property may present environmental risks and potential cleanup liability. In the event of default and foreclosure of a loan, ASB may become the owner of the mortgaged property. For that reason, ASB seeks to avoid lending upon the security of, or acquiring through foreclosure, any property with significant potential environmental risks; however, there can be no assurance that ASB will successfully avoid all such environmental risks.

Electric utility

Regulation of electric utility rates. The rates the electric utilities are allowed to charge for their services, and the timeliness of permitted rate increases, are among the most important items influencing their financial condition, results of operations and liquidity. The PUC has broad discretion over the rates the electric utilities charge and other matters. Any adverse decision by the PUC concerning the level or method of determining electric utility rates, the authorized returns on equity or rate base found to be reasonable, the potential consequences of exceeding or not meeting such returns, or any prolonged delay in rendering a decision in a rate or other proceeding could have a material adverse affect on the Company's and HECO's consolidated results of operations, financial condition and liquidity. Upon a showing of probable entitlement, the PUC is required to issue an interim D&O in a rate case within 10 months from the date of filing a completed application if the evidentiary hearing is completed (subject to extension for 30 days if the evidentiary hearing is not completed). There is no time limit for rendering a final D&O. Interim rate increases are subject to refund with interest, pending the final outcome of the case. Through December 31, 2006, HECO and its subsidiaries had recognized $79 million of revenues with respect to interim orders regarding certain integrated resource planning costs and HECO's general rate increase, which revenues are subject to refund, with interest, if and to the extent they exceed the amounts allowed in final orders. The Consumer Advocate has objected to the recovery of $2.9 million (before interest) of the $8.4 million of incremental IRP costs incurred by the utilities during the 1997-2005 period, and the PUC's decision is pending on this matter. In addition, MECO incurred approximately $0.7 million of incremental integrated resource planning costs for 2006, for which the Consumer Advocate has not yet stated its position. See "Most recent rate requests—HECO" above for a discussion of the status of the current HECO rate case.

Management cannot predict with certainty when the final D&Os in the pending two HECO rate cases, the HELCO rate case or the MECO rate case, or in future rate cases, will be rendered or the amount of any interim or final rate increase that may be granted. Further, the increasing levels of O&M expenses (including increased retirement benefit costs), increased plant-in-service, or other factors have and are likely to continue to result in the electric utilities seeking rate relief more often than in the past.

The rate schedules of each of HEI's electric utilities include energy cost adjustment clauses (ECACs) under which electric rates charged to customers are automatically adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power. In 2004 PUC decisions approving the electric utilities' fuel supply contracts, the PUC affirmed the electric utilities' right to include in their respective ECACs the stated costs incurred pursuant to their respective new fuel supply contracts, to the extent that these costs are not included in their respective base rates, and restated its intention to examine the need for continued use of ECACs in rate cases. Act 162 of the 2006 Hawaii legislature requires such examination and specifies certain factors that must be considered. See "Energy cost adjustment clauses" in Note 3 of HEI's "Notes to consolidated financial statements."

Fuel oil and purchased power. The electric utilities rely on fuel oil suppliers and IPPs to deliver fuel oil and power, respectively. See "Fuel contracts" and "Power purchase agreements (PPAs)" in Note 3 of HEI's "Notes to Consolidated Financial Statements." The Company estimates that 77.2% of the net energy generated and purchased by HECO and its subsidiaries in 2007 will be generated from the burning of oil. Purchased KWHs provided approximately 38.2% of the total net energy generated and purchased in 2006 compared to 39.1% in 2005 and 38.2% in 2004.

Failure or delay by the electric utilities' oil suppliers and shippers to provide fuel pursuant to existing supply contracts, or failure by a major independent power producer to deliver the firm capacity anticipated in its PPA, could interrupt the ability of the electric utilities to deliver electricity, thereby materially adversely affecting the Company's results of operations and financial condition. HECO generally maintains an average system fuel inventory level equivalent to 35 days of forward consumption. HELCO and MECO generally maintain an inventory level equivalent to one month's supply of both medium sulfur fuel oil and diesel fuel. The electric utilities' major sources of oil, through their suppliers, are in China, Vietnam and the Far East. Some, but not all, of the electric utilities' PPAs require that the IPPs maintain minimum fuel inventory levels and all of the firm capacity PPAs include provisions imposing substantial penalties for failure to produce the firm capacity anticipated by those agreements.

Other operation and maintenance expenses. Other operation and maintenance expenses increased 8%, 9% and 7% for 2006, 2005 and 2004, respectively, when compared to the prior year. This trend of increased operation and maintenance expenses is expected to continue in 2007 as the electric utilities anticipate: (1) higher DSM expenses (that are passed on to customers through a surcharge and therefore do not impact net income) and integrated resource planning expenses, (2) higher employee benefits expenses, primarily for retirement benefits and (3) higher production expenses, primarily to meet higher demand levels and load growth set in 2004 and sustained in 2005 and 2006. The timing and amount of these expenses can vary as circumstances change. For example, recent overhauls have been more expensive than in the past due to the larger scope of work necessary to maintain the aging equipment, which has experienced heavier usage as demand has increased to current levels. Until an overhaul is fully underway, it is possible that the maintenance costs for a generating unit may be significantly higher than originally planned. Increased operation and maintenance expenses were among the reasons HECO (in November 2004 and December 2006), HELCO (in May 2006) and MECO (in February 2007) filed requests with the PUC to increase base rates. In September 2005, HECO received interim rate relief for its request filed in November 2004 (see "Most recent rate requests").

Other regulatory and permitting contingencies. Many public utility projects require PUC approval and various permits (e.g., environmental and land use permits) from other agencies. Delays in obtaining PUC approval or permits can result in increased costs. If a project does not proceed or if the PUC disallows costs of the project, the project costs may need to be written off in amounts that could have a material adverse effect on the Company. Two major capital improvement utility projects, the Keahole project and the East Oahu Transmission Project, have encountered opposition and have been seriously delayed (although CT-4 and CT-5 at Keahole are now operating). See Note 3 of HEI's "Notes to Consolidated Financial Statements." HELCO is seeking to recover Keahole costs in its current rate case.

Bank

Regulation of ASB. ASB is subject to examination and comprehensive regulation by the Department of Treasury, OTS and the FDIC, and is subject to reserve requirements established by the Board of Governors of the Federal Reserve System. Regulation by these agencies focuses in large measure on the adequacy of ASB's capital and the results of periodic "safety and soundness" examinations conducted by the OTS. ASB's insurance product sales activities, including those conducted by ASB's insurance agency subsidiary, Bishop Insurance Agency of Hawaii, Inc., are subject to regulation by the Hawaii Insurance Commissioner.

Capital requirements. The OTS, which is ASB's principal regulator, administers two sets of capital standards—minimum regulatory capital requirements and prompt corrective action requirements. The FDIC also has prompt corrective action capital requirements. As of December 31, 2006, ASB was in compliance with OTS minimum regulatory capital requirements and was "well-capitalized" within the meaning of OTS prompt corrective action regulations and FDIC capital regulations, as follows:

- ASB met applicable minimum regulatory capital requirements (noted in parentheses) as of December 31, 2006 with a tangible capital ratio of 7.6% (1.5%), a core capital ratio of 7.6% (4.0%) and a total risk-based capital ratio of 14.7% (8.0%).
- ASB met the capital requirements to be generally considered "well-capitalized" (noted in parentheses) as of December 31, 2006 with a leverage ratio of 7.6% (5.0%), a Tier-1 risk-based capital ratio of 13.9% (6.0%) and a total risk-based capital ratio of 14.7% (10.0%).

The purpose of the prompt corrective action capital requirements is to establish thresholds for varying degrees of oversight and intervention by regulators. Declines in levels of capital, depending on their severity, will result in increasingly stringent mandatory and discretionary regulatory consequences. Capital levels may decline for any number of reasons, including reductions that would result if there were losses from operations, deterioration in collateral values or the inability to dispose of real estate owned (such as by foreclosure). The regulators have substantial discretion in the corrective actions they might direct and could include restrictions on dividends and other distributions that ASB may make to HEI (through HEIDI) and the requirement that ASB develop and implement a plan to restore its capital. Under an agreement with regulators entered into by HEI when it acquired ASB, HEI could be required to contribute to ASB up to an additional $28.3 million of capital, if necessary to maintain ASB's capital position.

Examinations. ASB is subject to periodic "safety and soundness" examinations and other examinations by the OTS. In conducting its examinations, the OTS utilizes the Uniform Financial Institutions Rating System adopted by the Federal Financial Institutions Examination Council, which system utilizes the "CAMELS" criteria for rating financial institutions. The six components in the rating system are: Capital adequacy, Asset quality, Management, Earnings, Liquidity and Sensitivity to market risk. The OTS examines and rates each CAMELS component. An overall CAMELS rating is also given, after taking into account all of the component ratings. A financial institution may be subject to formal regulatory or administrative direction or supervision such as a "memorandum of understanding" or a "cease and desist" order following an examination if its CAMELS rating is not satisfactory. An institution is prohibited from disclosing the OTS's report of its safety and soundness examination or the component and overall CAMELS rating to any person or organization not officially connected with the institution as an officer, director, employee, attorney, or auditor, except as provided by regulation. The OTS also regularly examines ASB's information technology practices, and its performance as related to the Community Reinvestment Act measurement criteria.

The Federal Deposit Insurance Act, as amended, addresses the safety and soundness of the deposit insurance system, supervision of depository institutions and improvement of accounting standards. Pursuant to this Act, federal banking agencies have promulgated regulations that affect the operations of ASB and its holding companies (e.g., standards for safety and soundness, real estate lending, accounting and reporting, transactions with affiliates and loans to insiders). FDIC regulations restrict the ability of financial institutions that fail to meet relevant capital measures to engage in certain activities, such as offering interest rates on deposits that are significantly higher than the rates offered by competing institutions. As of December 31, 2006, ASB was "well-capitalized" and thus not subject to these restrictions.

Qualified Thrift Lender status. ASB is a "qualified thrift lender" (QTL) under its federal thrift charter and, in order to maintain this status, ASB is required to maintain at least 65% of its assets in "qualified thrift investments," which include housing-related loans (including mortgage-related securities) as well as certain small business loans, education loans, loans made through credit card accounts and a basket (not exceeding 20% of total assets) of other consumer loans and other assets. Savings associations that fail to maintain QTL status are subject to various penalties, including limitations on their activities. In ASB's case, the activities of HEI, HEIDI and HEI's other subsidiaries would also be subject to restrictions if ASB failed to maintain its QTL status, and a failure or inability to comply with those restrictions could effectively result in the required divestiture of ASB. As of December 31, 2006, approximately 88% of its assets were qualified thrift investments.

Federal Thrift Charter. The Gramm-Leach-Bliley Act of 1998 (the Gramm Act) permitted banks, insurance companies and investment firms to compete directly against each other, thereby allowing "one-stop shopping" for an array of financial services. Although the Gramm Act further restricted the creation of so-called "unitary savings and loan holding companies" (i.e., companies such as HEI whose subsidiaries include one or more savings associations and one or more nonfinancial subsidiaries), the unitary savings and loan holding company relationship among HEI, HEIDI and ASB is "grandfathered" under the Gramm Act so that HEI and its subsidiaries will be able to continue to engage in their current activities so long as ASB maintains its QTL status. Under the Gramm Act, any proposed sale of ASB would have to satisfy applicable statutory and regulatory requirements and potential acquirers of ASB would most likely be limited to companies that are already qualified as, or capable of qualifying as, either a traditional savings and loan association holding company or a bank holding company, or as one of the newly authorized financial holding companies permitted under the Gramm Act.

Material estimates and critical accounting policies

In preparing financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses. Actual results could differ significantly from those estimates.

Material estimates that are particularly susceptible to significant change include the amounts reported for investment and mortgage-related securities; property, plant and equipment; pension and other postretirement benefit obligations; contingencies and litigation; income taxes; regulatory assets and liabilities; electric utility revenues; variable interest entities (VIEs); and allowance for loan losses. Management considers an accounting estimate to be material if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the assumptions selected could have a material impact on the estimate and on the Company's results of operations or financial condition. For example, in 2004, a significant change in estimated income taxes occurred as a result of a Tax Appeal Court decision (see "ASB state franchise tax dispute and settlement" in Note 10 of HEI's "Notes to Consolidated Financial Statements").

In accordance with SEC Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," management has identified the following accounting policies it believes to be the most critical to the Company's financial statements—that is, management believes that the policies below are both the most important to the portrayal of the Company's financial condition and results of operations, and currently require management's most difficult, subjective or complex judgments. These policies are identified according to whether they affect both of the Company's two principal segments, or just one of these segments. Management has reviewed the material estimates and critical accounting policies with the HEI Audit Committee and, as applicable, the HECO Audit Committee.

For additional discussion of the Company's accounting policies, see Note 1 of HEI's "Notes to Consolidated Financial Statements."

Consolidated

Investment and mortgage-related securities. Debt securities that the Company intends to and has the ability to hold to maturity are classified as held-to-maturity securities and reported at amortized cost. Marketable equity securities and debt securities that are bought and held principally for the purpose of selling them in the near term are classified as trading securities and reported at fair value, with unrealized gains and losses included in earnings. Marketable equity securities and debt securities not classified as either held-to-maturity or trading securities are classified as available-for-sale securities and reported at fair value, with unrealized gains and temporary losses excluded from earnings and reported in AOCI.

For securities that are not trading securities, declines in value determined to be other than temporary are included in earnings and result in a new cost basis for the investment. The specific identification method is used in determining realized gains and losses on the sales of securities.

ASB owns federal agency obligations, private-issue mortgage-related securities and mortgage-related securities issued by the Federal Home Loan Mortgage Corporation (FHLMC), Government National Mortgage Association (GNMA) and Federal National Mortgage Association (FNMA), all of which are classified as available-for-sale. ASB obtains market prices for investment and mortgage-related securities from a third party financial services provider. The prices of these securities may be influenced by factors such as market liquidity, corporate credit considerations of the underlying collateral, the levels of interest rates, expectations of prepayments and defaults, limited investor base, market sector concerns, and overall market psychology. Adverse changes in any of these factors may result in additional losses. As of December 31, 2006, ASB had mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $1.7 billion and private-issue mortgage-related securities valued at $0.5 billion.

Property, plant and equipment. Property, plant and equipment are reported at cost. Self-constructed electric utility plant includes engineering, supervision, and administrative and general costs, and an allowance for the cost of funds used during the construction period. These costs are recorded in construction in progress and are transferred to property, plant and equipment when construction is completed and the facilities are either placed in service or become useful for public utility purposes. Upon the retirement or sale of electric utility plant, no gain or loss is recognized. The cost of the plant retired is charged to accumulated depreciation. Amounts collected from customers for cost of removal (expected to exceed salvage value in the future) are included in regulatory liabilities.

HECO and its subsidiaries evaluate the impact of applying Emerging Issues Task Force (EITF) Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease," to their new PPAs, PPA amendments and other arrangements they enter into. A possible outcome of the evaluation is that an arrangement falls within the scope of EITF 01-8 and results in its classification as a capital lease, which could have a material effect on HECO's consolidated balance sheet if a significant amount of capital assets and lease obligations needed to be recorded.

Management believes that the PUC will allow recovery of property, plant and equipment in its electric rates. If the PUC does not allow recovery of any such costs, the electric utility would be required to write off the disallowed costs at that time. See the discussion in Note 3 of HEI's "Notes to Consolidated Financial Statements" concerning costs recorded for CT-4 and CT-5 at Keahole and the East Oahu Transmission Project.

Pension and other postretirement benefits obligations. Pension and other postretirement benefits (collectively, retirement benefits) costs are material estimates accounted for in accordance with SFAS No. 87, "Employers' Accounting for Pensions," SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" and 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)." For a discussion of retirement benefits (including costs, major assumptions, plan assets, other factors affecting costs, AOCI charges and sensitivity analyses), see "Retirement benefits (pension and other postretirement benefits)" in "Consolidated—Results of Operations" above and Note 8 of HEI's "Notes to Consolidated Financial Statements."

Contingencies and litigation. The Company is subject to proceedings, lawsuits and other claims, including proceedings under laws and government regulations related to environmental matters. Management assesses the likelihood of any adverse judgments in or outcomes to these matters as well as potential ranges of probable losses, including costs of investigation. A determination of the amount of reserves required, if any, for these contingencies is based on a careful analysis of each individual case or proceeding often with the assistance of outside counsel. The required reserves may change in the future due to new developments in each matter or changes in approach in dealing with these matters, such as a change in settlement strategy.

In general, environmental contamination treatment costs are charged to expense, unless it is probable that the PUC would allow such costs to be recovered through future rates, in which case such costs would be capitalized as regulatory assets. Also, environmental costs are capitalized if the costs extend the life, increase the capacity, or improve the safety or efficiency of property; the costs mitigate or prevent future environmental contamination; or the costs are incurred in preparing the property for sale. See "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements" for a description of the Honolulu Harbor investigation.

Income taxes. Deferred income tax assets and liabilities are established for the temporary differences between the financial reporting bases and the tax bases of the Company's assets and liabilities at enacted tax rates expected to be in effect when such deferred tax assets or liabilities are realized or settled. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

Management evaluates its potential exposures from tax positions taken that have or could be challenged by taxing authorities. These potential exposures result because taxing authorities may take positions that differ from those taken by management in the interpretation and application of statutes, regulations and rules. Management considers the possibility of alternative outcomes based upon past experience, previous actions by taxing authorities (e.g., actions taken in other jurisdictions) and advice from tax experts. Management believes that the Company's provision for tax contingencies is reasonable. However, the ultimate resolution of tax treatments disputed by governmental authorities may adversely affect the Company's current and deferred income tax amounts. See disclosure in Note 1 of HEI's "Notes to Consolidated Financial Statements" regarding the impact of changes made to estimating the impact of uncertain tax positions under FIN No. 48, which was adopted on January 1, 2007. Also, see Note 10, "Income taxes," of HEI's "Notes to Consolidated Financial Statements."

Electric utility

Regulatory assets and liabilities. The electric utilities are regulated by the PUC. In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," the Company's financial statements reflect assets, liabilities, revenues and costs of HECO and its subsidiaries based on current cost-based rate-making regulations. The actions of regulators can affect the timing of recognition of revenues, expenses, assets and liabilities.

Regulatory liabilities represent amounts collected from customers for costs that are expected to be incurred in the future. Regulatory assets represent incurred costs that have been deferred because their recovery in future customer rates is probable. As of December 31, 2006, regulatory liabilities and regulatory assets amounted to $241 million and $112 million, respectively. Regulatory liabilities and regulatory assets are itemized in Note 3 of HEI's "Notes to Consolidated Financial Statements." Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as changes in the applicable regulatory environment. Because current rates include the recovery of regulatory assets existing as of the last rate case and rates in effect allow the utilities to earn a reasonable rate of return, management believes that the recovery of the regulatory assets as of December 31, 2006 is probable. This determination assumes continuation of the current political and regulatory climate in Hawaii, and is subject to change in the future.

Management believes HECO and its subsidiaries' operations currently satisfy the SFAS No. 71 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to income and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, however, management believes that a material adverse effect on the Company's results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

Electric utility revenues. Electric utility revenues are based on rates authorized by the PUC and include revenues applicable to energy consumed in the accounting period but not yet billed to customers. As of December 31, 2006, revenues applicable to energy consumed, but not yet billed to customers, amounted to $92 million.

Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order. As of December 31, 2006, HECO and its subsidiaries had recognized $79 million of such revenues with respect to interim orders. Also, the rate schedules of the electric utilities include ECACs under which electric rates are adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power. See "Regulation of electric utility rates" above.

Consolidation of VIEs. In December 2003, the FASB issued revised FIN No. 46 (FIN 46R), "Consolidation of Variable Interest Entities," which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. The Company evaluates the impact of applying FIN 46R to its relationships with IPPs with whom the electric utilities execute new PPAs or execute amendments of existing PPAs. A possible outcome of the analysis is that HECO (or its subsidiaries, as applicable) may be found to meet the definition of a primary beneficiary of a VIE (the IPP) which finding may result in the consolidation of the IPP in HECO's consolidated financial statements. The consolidation of IPPs could have a material effect on HECO's consolidated financial statements, including the recognition of a significant amount of assets and liabilities, and, if such a consolidated IPP were operating at a loss and had insufficient equity, the potential recognition of such losses. The electric utilities do not know how the consolidation of IPPs would be treated for regulatory or credit ratings purposes. See "General—Consolidation—Consolidation of VIEs" in Note 1 of HEI's "Notes to Consolidated Financial Statements."

Allowance for loan losses. See Note 1 of HEI's "Notes to Consolidated Financial Statements." As of December 31, 2006, ASB's allowance for loan losses was $31.2 million and ASB had $2.4 million of loans on nonaccrual status. In 2006, ASB recorded a provision for loan losses of $1.4 million. Although management believes the allowance for loan losses is adequate, the actual loan losses, provision for loan losses and allowance for loan losses may be materially different if conditions change (e.g., if there is a significant change in the Hawaii economy), and material increases in those amounts could have a material adverse affect on the Company's results of operations and financial position.

Quantitative and Qualitative Disclosures about Market Risk

The Company manages various market risks in the ordinary course of business, including credit risk and liquidity risk. The Company believes the electric utility and other segments' exposures to these two risks are not material as of December 31, 2006.

Credit risk for ASB is the risk that borrowers or issuers of securities will not be able to repay their obligations to the bank. Credit risk associated with the lending portfolios is controlled through ASB's underwriting standards, loan rating of commercial and commercial real estate loans, on-going monitoring by loan officers, credit review and quality control functions in these lending areas and adequate allowance for loan losses. Credit risk associated with the securities portfolio is mitigated by ASB's asset/liability management process, experienced staff working with analytical tools, monthly fair value analysis and on-going monitoring and reporting such as investment watch reports and loss sensitivity analysis. See "Allowance for loan losses" above.

Liquidity risk for ASB is the risk that the bank will not meet its obligations when they become due. Liquidity risk is mitigated by ASB's asset/liability management process, on-going analytical analysis, monitoring and reporting information such as weekly cash-flow analyses and maintenance of liquidity contingency plans.

The Company is exposed to some commodity price risk primarily related to its fuel supply and IPP contracts. The Company's commodity price risk is substantially mitigated so long as the electric utilities have their current ECACs in their rate schedules. See discussion of the ECACs in "Certain factors that may affect future results and financial condition—Electric utility—Regulation of electric utility rates." The Company currently has no hedges against its commodity price risk. Because the Company does not have a large portfolio of trading assets, the Company is not exposed to significant market risk from trading activities. The Company's currently has no exposure to foreign currency exchange rate risk.

The Company considers interest rate risk to be a very significant market risk as it could potentially have a significant effect on the Company's results of operations and financial condition, especially as it relates to ASB, but also as it may affect the discount rate used to determine pension liabilities, the market value of pension plans' assets and the electric utilities' allowed rates of return. Interest rate risk can be defined as the exposure of the Company's earnings to adverse movements in interest rates.

Bank interest rate risk

The Company's success is dependent, in part, upon ASB's ability to manage interest rate risk. ASB's interest-rate risk profile is strongly influenced by its primary business of making fixed-rate residential mortgage loans and taking in retail deposits. Large mismatches in the amounts or timing between the maturity or repricing of interest sensitive assets or liabilities could adversely affect ASB's earnings and the market value of its interest-sensitive assets and liabilities in the event of significant changes in the level of interest rates. Many other factors also affect ASB's exposure to changes in interest rates, such as general economic and financial conditions, customer preferences, and competition for loans or deposits.

ASB's Asset/Liability Management Committee (ALCO), whose voting members are officers and employees of ASB, is responsible for managing interest rate risk and carrying out the overall asset/liability management objectives and activities of ASB as approved by the ASB Board of Directors. ALCO establishes policies under which management monitors and coordinates ASB's assets and liabilities.

See Note 4 of HEI's "Notes to Consolidated Financial Statements" for a discussion of the use of rate lock commitments on loans held for sale and forward sale contracts to manage some interest rate risk associated with ASB's residential loan sale program.

Management measures interest-rate risk using simulation analysis with an emphasis on measuring changes in net interest income (NII) and the market value of interest-sensitive assets and liabilities in different interest-rate environments. The simulation analysis is performed using a dedicated asset/liability management software system enhanced with a mortgage prepayment model and a collateralized mortgage obligation (CMO) database. The simulation software is capable of generating scenario-specific cash flows for all instruments using the specified contractual information for each instrument and product specific prepayment assumptions for mortgage loans and mortgage-related securities.

NII sensitivity analysis measures the change in ASB's twelve-month, pre-tax NII in alternate interest rate scenarios. NII sensitivity is measured as the change in NII in the alternate interest-rate scenarios as a percentage of the base case NII. The base case interest-rate scenario is established using the current yield curve and assumes interest rates remain constant over the next twelve months. The alternate scenarios were created by assuming "rate ramps" or gradual interest changes and accomplished by moving the yield curve in a parallel fashion, over the next twelve month period, in increments of +/- 100 basis points. The simulation model forecasts scenario-specific principal and interest cash flows for the interest-bearing assets and liabilities, and the NII is calculated for each scenario. Key balance sheet modeling assumptions used in the NII sensitivity analysis include: the size of the balance sheet remains relatively constant over the simulation horizon and maturing assets or liabilities are reinvested in similar instruments in order to maintain the current mix of the balance sheet. In addition, assumptions are made about the prepayment behavior of mortgage-related assets, future pricing spreads for new assets and liabilities, and the speed and magnitude with which deposit rates change in response to changes in the overall level of interest rates.

ASB's net portfolio value (NPV) ratio is a measure of the economic capitalization of ASB. The NPV ratio is the ratio of the net portfolio value of ASB to the present value of expected net cash flows from existing assets. Net portfolio value represents the theoretical market value of ASB's net worth and is defined as the present value of expected net cash flows from existing assets minus the present value of expected cash flows from existing liabilities plus the present value of expected net cash flows from existing off-balance sheet contracts. The NPV ratio is calculated by ASB pursuant to guidelines established by the OTS in Thrift Bulletin 13a. Key assumptions used in the calculation of ASB's NPV ratio include the prepayment behavior of loans and investments, the possible distribution of future interest rates, pricing spreads for assets and liabilities in the alternate scenarios and the rate and balance behavior of deposit accounts with indeterminate maturities. Typically, if the value of ASB's assets grows relative to the value of its liabilities, the NPV ratio will increase. Conversely, if the value of ASB's liabilities grows relative to the value of its assets, the NPV ratio will decrease. The NPV ratio is calculated in multiple scenarios. As with the NII simulation, the base case is represented by the current yield curve. Alternate scenarios are created by assuming immediate parallel shifts in the yield curve in increments of +/- 100 basis points.

The NPV ratio sensitivity measure is the change from the NPV ratio calculated in the base case to the NPV ratio calculated in the alternate rate scenarios. The sensitivity measure alone is not necessarily indicative of the interest-rate risk of an institution, as institutions with high levels of capital may be able to support a high sensitivity measure. This measure is evaluated in conjunction with the NPV ratio calculated in each scenario.

ASB's interest-rate risk sensitivity measures as of December 31, 2006 and 2005 constitute "forward-looking statements" and were as follows:

December 31	2006			2005		
	Change in NII	NPV ratio	NPV ratio sensitivity*	Change in NII	NPV ratio	NPV ratio sensitivity*
Change in interest rates (basis points)	Gradual change	Instantaneous change		Gradual change	Instantaneous change	
+300	(3.8)%	7.83%	(341)	(2.7)%	8.12%	(332)
+200	(2.6)	9.09	(215)	(1.8)	9.34	(210)
+100	(1.3)	10.29	(95)	(0.9)	10.49	(95)
Base	–	11.24	–	–	11.44	–
-100	2.0	11.64	40	1.5	11.91	47
-200	1.8	11.27	3	1.0	11.62	17
-300	0.3	10.60	(64)	*	*	*

* Change from base case in basis points.

Management believes that ASB's interest rate risk position as of December 31, 2006 represents a reasonable level of risk. Under the gradual interest rate change scenarios, the December 31, 2006 NII profile is slightly more sensitive to changes in interest rates compared to the NII profile on December 31, 2005. Shifts in ASB's funding mix contributed to the slight increase in sensitivity.

ASB's base NPV ratio as of December 31, 2006 was slightly lower than on December 31, 2005, primarily as a result of changes in the level and shape of the yield curve.

ASB's NPV ratio sensitivity measures as of December 31, 2006 were comparable to the measures as of December 31, 2005.

The computation of the prospective effects of hypothetical interest rate changes on the NII sensitivity, NPV ratio, and NPV ratio sensitivity analyses is based on numerous assumptions, including relative levels of market interest rates, loan prepayments, balance changes and pricing strategies, and should not be relied upon as indicative of actual results. To the extent market conditions and other factors vary from the assumptions used in the simulation analysis, actual results may differ materially from the simulation results. Furthermore, NII sensitivity analysis measures the change in ASB's twelve-month, pre-tax NII in alternate interest rate scenarios, and is intended to help management identify potential exposures in ASB's current balance sheet and formulate appropriate strategies for managing interest rate risk. The simulation does not contemplate any actions that ASB management might undertake in response to changes in interest rates. Further, the changes in NII vary in the twelve-month simulation period and are not necessarily evenly distributed over the period. These analyses are for analytical purposes only and do not represent management's views of future market movements, the level of future earnings, or the timing of any changes in earnings within the twelve month analysis horizon. The actual impact of changes in interest rates on NII will depend on the magnitude and speed with which rates change, actual changes in the ASB's balance sheet, and management's responses to the changes in interest rates.

Other than bank interest rate risk

The Company's general policy is to manage "other than bank" interest rate risk through use of a combination of short-term debt, long-term debt (primarily fixed-rate debt) and preferred securities. As of December 31, 2006, management believes the Company is exposed to "other than bank" interest rate risk because of their periodic borrowing requirements, the impact of interest rates on the discount rate and the market value of plan assets used to determine retirement benefits expenses and obligations (see "Retirement benefits (pension and other postretirement benefits)" in "Management's discussion and analysis of financial condition and results of operations" and Note 8 of HEI's "Notes to Consolidated Financial Statements") and the possible effect of interest rates on the electric utilities' allowed rates of return (see "Regulation of electric utility rates"). Other than these exposures, management believes its exposure to "other than bank" interest rate risk is not material. Based upon commercial paper outstanding as of December 31, 2006 of $177 million and a hypothetical 10% increase/decrease in interest rates, annual interest expense would have increased/decreased on that commercial paper by $1 million.

Annual Report of Management on Internal Control Over Financial Reporting

The Board of Directors and Shareholders
Hawaiian Electric Industries, Inc.:

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934, as amended. The Company's internal control system was designed to provide reasonable assurance to management and the Board of Directors regarding the preparation and fair presentation of its consolidated financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has concluded that the Company's internal control over financial reporting was effective as of December 31, 2006.

KPMG LLP, an independent registered public accounting firm, has issued an audit report on management's assessment of the Company's internal control over financial reporting as of December 31, 2006. This report appears on page 54.

Constance H. Lau
President and
Chief Executive Officer

Eric K. Yeaman
Financial Vice President,
Treasurer and
Chief Financial Officer

Curtis Y. Harada
Controller and
Chief Accounting Officer

February 28, 2007

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Shareholders
Hawaiian Electric Industries, Inc.:

We have audited management's assessment, included in the accompanying annual report of management on internal control over financial reporting, that Hawaiian Electric Industries, Inc. maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Hawaiian Electric Industries, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Hawaiian Electric Industries, Inc. maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control—Integrated Framework issued by the COSO. Also, in our opinion, Hawaiian Electric Industries, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2006, and our report dated February 28, 2007 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Honolulu, Hawaii
February 28, 2007

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Hawaiian Electric Industries, Inc.:

We have audited the accompanying consolidated balance sheets of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2006. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (Revised 2004), *Share-Based Payment*, and, effective December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Hawaiian Electric Industries, Inc.'s internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28, 2007 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Honolulu, Hawaii
February 28, 2007

Consolidated Financial Statements

Consolidated Statements of Income

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2006	2005	2004
(in thousands, except per share amounts)			
Revenues			
Electric utility	$ 2,054,890	$ 1,806,384	$ 1,550,671
Bank	408,365	387,910	364,284
Other	(2,351)	21,270	9,102
	2,460,904	2,215,564	1,924,057
Expenses			
Electric utility	1,888,172	1,644,681	1,376,768
Bank	319,807	283,009	259,310
Other	13,529	16,452	17,019
	2,221,508	1,944,142	1,653,097
Operating income (loss)			
Electric utility	166,718	161,703	173,903
Bank	88,558	104,901	104,974
Other	(15,880)	4,818	(7,917)
	239,396	271,422	270,960
Interest expense – other than bank	(75,678)	(75,309)	(77,176)
Allowance for borrowed funds used during construction	2,879	2,020	2,542
Preferred stock dividends of subsidiaries	(1,890)	(1,894)	(1,901)
Allowance for equity funds used during construction	6,348	5,105	5,794
Income from continuing operations before income taxes	171,055	201,344	200,219
Income taxes	63,054	73,900	92,480
Income from continuing operations	108,001	127,444	107,739
Discontinued operations – gain (loss) on disposal, net of income taxes	–	(755)	1,913
Net income	$ 108,001	$ 126,689	$ 109,652
Basic earnings (loss) per common share			
Continuing operations	$ 1.33	$ 1.58	$ 1.36
Discontinued operations	–	(0.01)	0.02
	$ 1.33	$ 1.57	$ 1.38
Diluted earnings (loss) per common share			
Continuing operations	$ 1.33	$ 1.57	$ 1.36
Discontinued operations	–	(0.01)	0.02
	$ 1.33	$ 1.56	$ 1.38
Dividends per common share	$ 1.24	$ 1.24	$ 1.24
Weighted-average number of common shares outstanding	81,145	80,828	79,562
Dilutive effect of stock-based compensation	228	372	157
Adjusted weighted-average shares	81,373	81,200	79,719

See accompanying "Notes to Consolidated Financial Statements."

Consolidated Balance Sheets

Hawaiian Electric Industries, Inc. and Subsidiaries

December 31		2006		2005
(dollars in thousands)				
ASSETS				
Cash and equivalents		$ 177,630		$ 151,513
Federal funds sold		79,671		57,434
Accounts receivable and unbilled revenues, net		248,639		249,473
Available-for-sale investment and mortgage-related securities		2,367,427		2,629,351
Investment in stock of Federal Home Loan Bank of Seattle (estimated fair value $97,764)		97,764		97,764
Loans receivable, net		3,780,461		3,566,834
Property, plant and equipment, net				
Land	$ 48,558		$ 46,350	
Plant and equipment	4,148,707		3,884,886	
Construction in progress	101,313		150,376	
	4,298,578		4,081,612	
Less – accumulated depreciation	(1,651,088)	2,647,490	(1,538,836)	2,542,776
Regulatory assets		112,349		110,718
Other		292,638		456,134
Goodwill and other intangibles, net		87,140		89,580
		$ 9,891,209		$ 9,951,577
LIABILITIES AND STOCKHOLDERS' EQUITY				
Liabilities				
Accounts payable		$ 165,505		$ 183,336
Deposit liabilities		4,575,548		4,557,419
Short-term borrowings—other than bank		176,272		141,758
Other bank borrowings		1,568,585		1,622,294
Long-term debt, net—other than bank		1,133,185		1,142,993
Deferred income taxes		106,780		207,997
Regulatory liabilities		240,619		219,204
Contributions in aid of construction		276,728		256,263
Other		518,454		369,390
		8,761,676		8,700,654
Minority interests				
Preferred stock of subsidiaries – not subject to mandatory redemption		34,293		34,293
Stockholders' equity				
Preferred stock, no par value, authorized 10,000,000 shares; issued: none		–		–
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding: 81,461,409 shares and 80,983,326 shares		1,028,101		1,018,966
Retained earnings		242,667		235,394
Accumulated other comprehensive loss, net of income tax benefits				
Net unrealized losses on securities	$ (35,462)		$(36,476)	
Minimum pension liability	–		(1,254)	
Defined benefit pension and postretirement benefit plans	(140,066)	(175,528)	–	(37,730)
		1,095,240		1,216,630
		$ 9,891,209		$ 9,951,577

See accompanying "Notes to Consolidated Financial Statements."

Consolidated Statements of Changes in Stockholders' Equity

Hawaiian Electric Industries, Inc. and Subsidiaries

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance, December 31, 2003	75,838	$888,431	$197,774	$ 2,826	$1,089,031
Comprehensive income:					
Net income	–	–	109,652	–	109,652
Net unrealized losses on securities:					
Net unrealized losses arising during the period, net of tax benefits of $4,366	–	–	–	(7,775)	(7,775)
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $2,002	–	–	–	(3,535)	(3,535)
Minimum pension liability adjustment, net of taxes of $197	–	–	–	341	341
Comprehensive income (loss)	–	–	109,652	(10,969)	98,683
Issuance of common stock:					
Common stock offering	4,000	103,720			103,720
Dividend reinvestment and stock purchase plan	307	7,999	–	–	7,999
Retirement savings and other plans	542	10,128	–	–	10,128
Expenses and other, net	–	(188)	–	–	(188)
Common stock dividends ($1.24 per share)	–	–	(98,428)	–	(98,428)
Balance, December 31, 2004	80,687	1,010,090	208,998	(8,143)	1,210,945
Comprehensive income:					
Net income	–	–	126,689	–	126,689
Net unrealized losses on securities:					
Net unrealized losses arising during the period, net of tax benefits of $21,933	–	–	–	(29,335)	(29,335)
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $70	–	–	–	(105)	(105)
Minimum pension liability adjustment, net of tax benefits of $95	–	–	–	(147)	(147)
Comprehensive income (loss)	–	–	126,689	(29,587)	97,102
Issuance of common stock:					
Stock Option and Incentive Plan and other plans	296	6,095	–	–	6,095
Expenses and other, net	–	2,781	–	–	2,781
Common stock dividends ($1.24 per share)	–	–	(100,293)	–	(100,293)
Balance, December 31, 2005	80,983	$1,018,966	$235,394	$(37,730)	$1,216,630
Comprehensive income:					
Net income	–	–	108,001	–	108,001
Net unrealized gains on securities:					
Net unrealized gains arising during the period, net of taxes of $1,361	–	–	–	2,059	2,059
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $690	–	–	–	(1,045)	(1,045)
Minimum pension liability adjustment, net of taxes of $804	–	–	–	1,254	1,254
Comprehensive income (loss)	–	–	108,001	2,268	110,269
Adjustment to initially apply SFAS No. 158, net of tax benefits of $89,394 (includes pension liability adjustment of $145, net of tax benefits of $91, which would have also been recorded under SFAS No. 87)	–	–	–	(140,066)	(140,066)
Issuance of common stock:					
Stock Option and Incentive Plan and other plans	478	10,270	–	–	10,270
Expenses and other, net	–	(1,135)	–	–	(1,135)
Common stock dividends ($1.24 per share)	–	–	(100,728)	–	(100,728)
Balance, December 31, 2006	81,461	$1,028,101	$ 242,667	$(175,528)	$1,095,240

As of December 31, 2006, Hawaiian Electric Industries, Inc. (HEI) had reserved a total of 16,810,697 shares of common stock for future issuance under the HEI Dividend Reinvestment and Stock Purchase Plan, the Hawaiian Electric Industries Retirement Savings Plan, the 1987 Stock Option and Incentive Plan and the HEI 1990 Nonemployee Director Stock Plan.

In 1997, the HEI Board of Directors adopted a resolution designating 500,000 shares of Series A Junior Participating Preferred Stock in connection with HEI's Shareholders Rights Plan, but no shares have been issued.

See accompanying "Notes to Consolidated Financial Statements."

Consolidated Statements of Cash Flows

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2006	2005	2004
(in thousands)			
Cash flows from operating activities			
Net income	$ 108,001	$ 126,689	$ 109,652
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation of property, plant and equipment	141,184	133,892	125,560
Other amortization	10,778	8,269	15,965
Provision (reversal of allowance) for loan losses	1,400	(3,100)	(8,400)
Gain on sale of income notes	–	–	(5,607)
Deferred income taxes	(12,946)	43	12,349
Allowance for equity funds used during construction	(6,348)	(5,105)	(5,794)
Excess tax benefits from share-based payment arrangements	(1,052)	–	–
Changes in assets and liabilities, net of effects from the disposal of businesses			
Decrease (increase) in accounts receivable and unbilled revenues, net	834	(40,940)	(20,823)
Decrease (increase) in fuel oil stock	21,138	(26,880)	(14,958)
Decrease (increase) in federal tax deposit	30,000	(30,000)	–
Increase (decrease) in accounts payable	(17,831)	36,282	17,913
Increase (decrease) in taxes accrued	(2,273)	37,631	46,675
Changes in other assets and liabilities	13,167	(18,343)	(28,380)
Net cash provided by operating activities	286,052	218,438	244,152
Cash flows from investing activities			
Available-for-sale investment and mortgage-related securities purchased	(343,927)	(486,432)	(1,105,133)
Principal repayments on available-for-sale investment and mortgage-related securities	542,702	727,901	803,517
Proceeds from sale of available-for-sale mortgage-related securities	61,131	28,039	45,207
Net increase in loans held for investment	(211,872)	(304,212)	(113,991)
Net proceeds from sale of investments	–	33,809	9,981
Proceeds from sale of real estate acquired in settlement of loans	403	624	1,617
Capital expenditures	(210,529)	(223,675)	(214,654)
Contributions in aid of construction	19,707	21,083	8,522
Distributions from unconsolidated subsidiaries	–	–	24,379
Other	1,708	909	180
Net cash used in investing activities	(140,677)	(201,954)	(540,375)
Cash flows from financing activities			
Net increase in deposit liabilities	18,129	261,247	269,922
Net increase in short-term borrowings with original maturities of three months or less	35,213	65,147	76,611
Proceeds from short-term borrowings with original maturities of greater than three months	44,891	–	–
Repayment of short-term borrowings with original maturities of greater than three months	(45,590)	–	–
Net increase in retail repurchase agreements	60,596	18,519	25,050
Proceeds from other bank borrowings	1,331,559	1,068,256	882,808
Repayments of other bank borrowings	(1,446,995)	(1,265,376)	(957,272)
Proceeds from issuance of long-term debt	100,000	59,462	103,097
Repayment of long-term debt	(110,000)	(84,000)	(224,166)
Excess tax benefits from share-based payment arrangements	1,052	–	–
Net proceeds from issuance of common stock	5,481	3,689	110,017
Common stock dividends	(100,673)	(100,238)	(93,864)
Other	1,786	(5,015)	(4,768)
Net cash provided by (used in) financing activities	(104,551)	21,691	187,435
Cash flows from discontinued operations (revised – see Note 11)			
Cash flows provided by (used in) operating activities	7,530	(2,857)	(3,571)
Cash flows provided by investing activities	–	–	6,000
Net cash provided by (used in) discontinued operations	7,530	(2,857)	2,429
Net increase (decrease) in cash and equivalents and federal funds sold	48,354	35,318	(106,359)
Cash and equivalents and federal funds sold, January 1	208,947	173,629	279,988
Cash and equivalents and federal funds sold, December 31	$ 257,301	$ 208,947	$ 173,629

See accompanying "Notes to Consolidated Financial Statements."

1 • Summary of significant accounting policies

General

HEI is a holding company with direct and indirect subsidiaries engaged in electric utility, banking and other businesses, primarily in the State of Hawaii. HEI's common stock is traded on the New York Stock Exchange.

Basis of presentation. In preparing the consolidated financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses. Actual results could differ significantly from those estimates.

Material estimates that are particularly susceptible to significant change include the amounts reported for investment securities; property, plant and equipment; pension and other postretirement benefit obligations; contingencies and litigation; income taxes; regulatory assets and liabilities; electric utility revenues; variable interest entities (VIEs); and allowance for loan losses.

Consolidation. The consolidated financial statements include the accounts of HEI and its subsidiaries (collectively, the Company), but exclude subsidiaries which are variable-interest entities of which the Company is not the primary beneficiary. Investments in companies over which the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method. All material intercompany accounts and transactions have been eliminated in consolidation.

See Note 5 for information regarding the application of FASB Interpretation No. 46(R).

Cash and equivalents and federal funds sold. The Company considers cash on hand, deposits in banks, deposits with the Federal Home Loan Bank (FHLB) of Seattle, money market accounts, certificates of deposit, short-term commercial paper of non-affiliates and reverse repurchase agreements and liquid investments (with original maturities of three months or less) to be cash and equivalents. Federal funds sold are excess funds that ASB loans to other banks overnight at the federal funds rate.

Investment and mortgage-related securities. Debt securities that the Company intends to and has the ability to hold to maturity are classified as held-to-maturity securities and reported at amortized cost. Marketable equity securities and debt securities that are bought and held principally for the purpose of selling them in the near term are classified as trading securities and reported at fair value, with unrealized gains and losses included in earnings. Marketable equity securities and debt securities not classified as either held-to-maturity or trading securities are classified as available-for-sale securities and reported at fair value, with unrealized gains and temporary losses excluded from earnings and reported on a net basis in accumulated other comprehensive income (AOCI).

For securities that are not trading securities, declines in value determined to be other-than-temporary are included in earnings and result in a new cost basis for the investment. The specific identification method is used in determining realized gains and losses on the sales of securities. To determine whether an impairment is other-than-temporary, the Company considers whether it has the ability and intent to hold the investment until a market price recovery and considers whether evidence indicating the cost of the investment is recoverable outweighs evidence to the contrary. Evidence considered in this assessment includes the magnitude of the impairment, the severity and duration of the impairment, changes in value subsequent to year-end and forecasted performance of the investment.

Discounts and premiums on investment and mortgage-related securities are accreted or amortized over the remaining lives of the securities, adjusted for actual portfolio prepayments, using the interest method.

Equity method. Investments in up to 50%-owned affiliates over which the Company has the ability to exercise significant influence over the operating and financing policies and investments in unconsolidated subsidiaries (e.g. HECO Capital Trust III) are accounted for under the equity method, whereby the investment is carried at cost, plus (or minus) the Company's equity in undistributed earnings (or losses) and minus distributions since acquisition. Equity in earnings or losses are reflected in operating revenues.

Property, plant and equipment. Property, plant and equipment are reported at cost. Self-constructed electric utility plant includes engineering, supervision, administrative and general costs and an allowance for the cost of funds used during the construction period. These costs are recorded in construction in progress and are transferred to property, plant and equipment when construction is completed and the facilities are either placed in service or become useful for public utility purposes. Costs for betterments that make property, plant or equipment more useful, more efficient, of greater durability or of greater capacity are also capitalized. Upon the retirement or sale of electric utility plant, generally no gain or loss is recognized. The cost of the plant retired is charged to accumulated depreciation. Amounts collected from customers for cost of removal (expected to exceed salvage value in the future) are included in regulatory liabilities.

If a PPA falls within the scope of Emerging Issues Task Force (EITF) Issue No. 01-8, “Determining Whether an Arrangement Contains a Lease” and results in the classification of the agreement as a capital lease, the electric utility would recognize a capital asset and a lease obligation.

Depreciation. Depreciation is computed primarily using the straight-line method over the estimated lives of the assets being depreciated. Electric utility plant additions in the current year are depreciated beginning January 1 of the following year. Electric utility plant has lives ranging from 20 to 45 years for production plant, from 25 to 60 years for transmission and distribution plant and from 7 to 45 years for general plant. The electric utilities’ composite annual depreciation rate, which includes a component for cost of removal, was 3.9% in 2006, 2005 and 2004.

Retirement benefits. Pension and other postretirement benefit costs are charged primarily to expense and electric utility plant. The Public Utilities Commission of the State of Hawaii (PUC) requires the electric utilities to fund their pension and postretirement benefit costs. The Company’s policy is to fund qualified pension plan costs in amounts that will not be less than the minimum funding requirements of the Employee Retirement Income Security Act of 1974 and will not exceed the maximum tax-deductible amounts. The Company generally funds at least the net periodic pension cost as calculated using Statement of Financial Accounting Standards (SFAS) No. 87 during the fiscal year, subject to limits and targeted funded status as determined with the consulting actuary. Certain health care and/or life insurance benefits are provided to eligible retired employees and the employees’ beneficiaries and covered dependents. The Company generally funds the net periodic postretirement benefit costs other than pensions as calculated using SFAS No. 106 and the amortization of the regulatory asset for postretirement benefits other than pensions, while maximizing the use of the most tax advantaged funding vehicles, subject to cash flow requirements and reviews of the funded status with the consulting actuary.

Effective December 31, 2006, the Company adopted 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),” and recognized on its balance sheet the funded status of its defined benefit pension and other postretirement benefit plans. See Note 8 for the impacts of adoption.

Environmental expenditures. The Company is subject to numerous federal and state environmental statutes and regulations. In general, environmental contamination treatment costs are charged to expense, unless it is probable that the PUC would allow such costs to be recovered in future rates, in which case such costs would be capitalized as regulatory assets. Also, environmental costs are capitalized if the costs extend the life, increase the capacity, or improve the safety or efficiency of property; the costs mitigate or prevent future environmental contamination; or the costs are incurred in preparing the property for sale. Environmental costs are either capitalized or charged to expense when environmental assessments and/or remedial efforts are probable and the cost can be reasonably estimated.

Financing costs. HEI uses the effective interest method to amortize the financing costs of the holding company over the term of the related long-term debt.

HECO and its subsidiaries use the straight-line method to amortize financing costs and premiums or discounts over the term of the related long-term debt. Unamortized financing costs and premiums or discounts on HECO and its subsidiaries' long-term debt retired prior to maturity are classified as regulatory assets or liabilities and are amortized on a straight-line basis over the remaining original term of the retired debt. The method and periods for amortizing financing costs, premiums and discounts, including the treatment of these items when long-term debt is retired prior to maturity, have been established by the PUC as part of the rate-making process.

HEI and HECO and its subsidiaries use the straight-line method to amortize the fees and related costs paid to secure a firm commitment under their line-of-credit arrangements.

Income taxes. Deferred income tax assets and liabilities are established for the temporary differences between the financial reporting bases and the tax bases of the Company's assets and liabilities at enacted tax rates expected to be in effect when such deferred tax assets or liabilities are realized or settled. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

Federal and state investment tax credits are deferred and amortized over the estimated useful lives of the properties which qualified for the credits.

Governmental tax authorities could challenge a tax return position taken by management. If the Company's position does not prevail, the Company's results of operations and financial condition may be adversely affected as the related deferred or current income tax asset might be impaired and written down or written off.

Effective January 1, 2007, the Company adopted FIN No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109," and uses a "more-likely-than-not" recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return.

Earnings per share. Basic earnings per share (EPS) is computed by dividing net income by the weighted-average number of common shares outstanding for the period. Diluted EPS is computed similarly, except that common shares for dilutive stock compensation are added to the denominator.

As of December 31, 2006 and 2004, the dilutive effect of all options, stock appreciation rights (SARs) and restricted stock were included in the computation of diluted EPS. As of December 31, 2005, the antidilutive effect of SARs on 879,000 shares of common stock (for which the SARs' exercise prices were greater than the closing market price of HEI's common stock) were not included in the computation of diluted EPS.

Share-based compensation. For 2005 and 2004, the Company applied the fair value based method of accounting prescribed by SFAS No. 123, "Accounting for Stock-Based Compensation," to account for its stock compensation. Since January 1, 2006, the Company applied the fair value based method of accounting prescribed by SFAS No. 123 (Revised 2004), "Share-Based Payment," to account for its stock compensation, including the use of a forfeiture assumption. See Note 9 for the impacts of adoption.

Impairment of long-lived assets and long-lived assets to be disposed of. The Company reviews long-lived assets and certain identifiable intangibles for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell.

Recent accounting pronouncements and interpretations

Accounting for certain hybrid financial instruments. In March 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments," which amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation, and clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of the first fiscal year that begins after September 15, 2006. The Company adopted SFAS No. 155 on January 1, 2007 and the adoption had no impact on the Company's results of operations, financial condition or liquidity.

Accounting for servicing of financial assets. In March 2006, the FASB issued SFAS No. 156, "Accounting for Servicing of Financial Assets." This statement amends SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 156 requires an entity to recognize, in certain situations, a servicing asset or servicing liability when it undertakes an obligation to service a financial asset, requires all separately recognized servicing assets and liabilities to be initially measured at fair value (if practicable), permits alternative subsequent measurement methods for each class of servicing assets and liabilities, permits a limited one-time reclassification of available-for-sale securities to trading securities at adoption, requires separate presentation of servicing assets and liabilities subsequently measured at fair value in the balance sheet and requires additional disclosures. SFAS No. 156 must be adopted by the beginning of the first fiscal year that begins after September 15, 2006. The Company adopted SFAS No. 156 on January 1, 2007 and the adoption had no impact on the Company's results of operations, financial condition or liquidity.

Accounting for uncertainty in income taxes. In June 2006, the FASB issued FIN No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109." This interpretation prescribes a "more-likely-than-not" recognition threshold and measurement attribute (the largest amount of benefit that is greater than 50% likely of being realized upon ultimate resolution with tax authorities) for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The Company adopted FIN No. 48 in the first quarter of 2007. The Company anticipates reclassifying certain deferred tax liabilities to a liability for tax uncertainties. Further, although management's analysis of the impact of adoption of FIN No. 48 is ongoing, management does not expect the adjustment to retained earnings as of January 1, 2007 for the cumulative effect of adoption of FIN No. 48 to be material.

Cash flows relating to income taxes generated by a leveraged lease transaction. In July 2006, the FASB issued FASB Staff Position (FSP) No. 13-2, "Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction," which requires a recalculation of the rate of return and the allocation of income to positive investment years from the inception of the lease if there is a change or projected change in the timing of cash flows relating to income taxes generated by the leveraged lease. The amounts comprising the net leveraged lease investment would be adjusted to the recalculated amounts, and the change in the net investment would be recognized as a gain or loss in the year in which the projected cash flows and/or assumptions change. FSP No. 13-2 is effective for fiscal years beginning after December 15, 2006. The Company adopted FSP No. 13-2 on January 1, 2007 and the adoption had no impact on the Company's results of operations, financial condition or liquidity.

Fair value measurements. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value under GAAP and expands disclosures about fair value measurements. SFAS No. 157 applies to fair value measurements that are already required or permitted under existing accounting pronouncements with some exceptions. SFAS No. 157 retains the exchange price notion in defining fair value and clarifies that the exchange price is the price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability. It emphasizes that fair value is a market-based, not an entity-specific, measurement based upon the assumptions that market participants would use in pricing an asset or liability. As a basis for considering assumptions in fair value measurements, SFAS No. 157 establishes a hierarchy that gives the highest priority to quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). SFAS No. 157 expands disclosures about the use of fair value, including disclosure of the level within the hierarchy in which the fair value measurements fall and the effect of the measurements on earnings (or changes in net assets) for the period. SFAS No. 157 must be adopted by the first quarter of the fiscal year beginning after November 15, 2007. The Company plans to adopt SFAS No. 157 on January 1, 2008. Management has not yet determined what impact, if any, the adoption of SFAS No. 157 will have on the Company's financial statements.

Effects of prior year misstatements. In September 2006, the SEC staff issued Staff Accounting Bulletin (SAB) No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," which provides guidance on how prior year misstatements should be taken into consideration when quantifying misstatements in current year financial statements for purposes of determining whether the current year's financial statements are materially misstated. In order to evaluate whether an error is material based on all relevant quantitative and qualitative factors, SAB No. 108 requires the quantification of misstatements using both the income-statement (rollover) and balance sheet (iron curtain) approaches. If the Company does not elect to restate its financial statements for the material misstatements that arise in connection with application of the guidance in SAB No. 108, then for fiscal years ending after November 15, 2006, it must recognize the cumulative effect of applying SAB No. 108 in the current year beginning balances of the affected assets and liabilities with a corresponding adjustment to the current year opening balance in retained earnings. The Company adopted SAB No. 108 in the fourth quarter of 2006 and the adoption had no impact on the Company's results of operations, financial condition or liquidity.

Planned major maintenance activities. In September 2006, the FASB issued FASB Staff Position (FSP) AUG AIR-1, "Accounting for Planned Major Maintenance Activities," which eliminates the accrue-in-advance method of accounting for planned major maintenance activities. As a result of the elimination, three methods are currently permitted: (1) direct expensing, (2) built-in overhaul, and (3) deferral. FSP AUG AIR-1 must be adopted by the first fiscal year beginning after December 15, 2006. The Company adopted FSP AUG AIR-1 on January 1, 2007 and the adoption had no impact on the Company's results of operations, financial condition or liquidity because the Company has used and continues to use the direct expensing method.

Defined benefit pension and other postretirement plans. In September 2006, the FASB issued 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)," which requires employers to recognize on their balance sheets the funded status of defined benefit pension and other postretirement benefit plans. Employers must recognize actuarial gains and losses, prior service cost, and any remaining transition amounts from the initial application of SFAS Nos. 87 and 106 when recognizing a plan's funded status, with the offset to AOCI in stockholders' equity. SFAS No. 158 was required to be adopted in fiscal years ending after December 15, 2006. Accordingly, the Company adopted SFAS No. 158 on December 31, 2006. The electric utilities updated their application in the AOCI Docket to take into account SFAS No. 158 in seeking PUC approval to record as a regulatory asset the amount that would otherwise be charged against stockholders' equity, but the application was denied. See Note 8 for the impacts of adoption.

The fair value option for financial assets and financial liabilities. In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities, Including an amendment of FASB Statement No. 115.” SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value, which should improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 must be adopted by January 1, 2008. Management has not yet determined when it will adopt SFAS No. 159 or what impact, if any, the adoption of SFAS No. 159 will have on the Company’s financial statements.

Common stock split. On April 20, 2004, the HEI Board of Directors approved a 2-for-1 stock split in the form of a 100% stock dividend with a record date of May 10, 2004 and a distribution date of June 10, 2004. All share and per share information in the accompanying financial statements and notes has been adjusted to reflect the stock split for all periods presented (unless otherwise noted).

Reclassifications. Certain reclassifications have been made to prior years’ financial statements to conform to the 2006 presentation.

Electric utility

Regulation by the PUC. The electric utilities are regulated by the PUC and account for the effects of regulation under SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation.” As a result, the actions of regulators can affect the timing of recognition of revenues, expenses, assets and liabilities. Management believes HECO and its subsidiaries’ operations currently satisfy the SFAS No. 71 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to income and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, however, management believes that a material adverse effect on the Company’s results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

Accounts receivable. Accounts receivable are recorded at the invoiced amount. The electric utilities assess a late payment charge on balances unpaid from the previous month. The allowance for doubtful accounts is the Company’s best estimate of the amount of probable credit losses in the Company’s existing accounts receivable. The Company adjusts its allowance on a monthly basis, based on its historical write-off experience. Account balances are charged off against the allowance after collection efforts have been exhausted and the potential for recovery is considered remote.

Contributions in aid of construction. The electric utilities receive contributions from customers for special construction requirements. As directed by the PUC, contributions are amortized on a straight-line basis over 30 years as an offset against depreciation expense.

Electric utility revenues. Electric utility revenues are based on rates authorized by the PUC and include revenues applicable to energy consumed in the accounting period but not yet billed to the customers. Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers for billing purposes is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on the meter readings in the beginning of the following month, monthly generation volumes, estimated customer usage by account, line losses and applicable customer rates based on historical values and current rate schedules. As of December 31, 2006, customer accounts receivable include unbilled energy revenues of $92 million on a base of annual revenue of $2.1 billion. Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order.

The rate schedules of the electric utilities include energy cost adjustment clauses (ECACs) under which electric rates are adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power. The ECACs also include a provision requiring a quarterly reconciliation of the amounts collected through the ECACs. In 2004 PUC decisions approving the electric utilities' fuel supply contracts, the PUC affirmed the electric utilities' right to include in their respective ECACs the stated costs incurred pursuant to their respective new fuel supply contracts, to the extent that these costs are not included in their respective base rates, and restated its intention to examine the need for continued use of ECACs in rate cases. See "Energy cost adjustment clauses" in Note 3.

HECO and its subsidiaries' operating revenues include amounts for various revenue taxes. Revenue taxes are generally recorded as an expense in the year the related revenues are recognized. HECO and its subsidiaries' payments to the taxing authorities are based on the prior years' revenues. For 2006, 2005 and 2004, HECO and its subsidiaries included approximately $182 million, $159 million and $136 million, respectively, of revenue taxes in "operating revenues" and in "taxes, other than income taxes" expense.

Repairs and maintenance costs. Repairs and maintenance costs for overhauls of generating units are generally expensed as they are incurred.

Allowance for funds used during construction (AFUDC). AFUDC is an accounting practice whereby the costs of debt and equity funds used to finance plant construction are credited on the statement of income and charged to construction in progress on the balance sheet. If a project under construction is delayed for an extended period of time, AFUDC may be stopped.

The weighted-average AFUDC rate was 8.4%, 8.5% and 8.6% in 2006, 2005 and 2004, respectively, and reflected quarterly compounding.

Bank

Loans receivable. American Savings Bank, F.S.B. and subsidiaries (ASB) state loans receivable at amortized cost less the allowance for loan losses, loan origination fees (net of direct loan origination costs), commitment fees and purchase premiums and discounts. Interest on loans is credited to income as it is earned. Discounts and premiums are accreted or amortized over the life of the loans using the interest method.

Loan origination fees (net of direct loan origination costs) are deferred and recognized as an adjustment in yield over the life of the loan using the interest method or taken into income when the related loans are paid off or sold. Nonrefundable commitment fees (net of direct loan origination costs, if applicable) received for commitments to originate or purchase loans are deferred and, if the commitment is exercised, recognized as an adjustment of yield over the life of the loan using the interest method. Nonrefundable commitment fees received for which the commitment expires unexercised are recognized as income upon expiration of the commitment.

Loans held for sale, gain on sale of loans, and mortgage servicing rights. Mortgage and educational loans held for sale are stated at the lower of cost or estimated market value on an aggregate basis. Generally, the determination of market value is based on the fair value of the loans. A sale is recognized only when the consideration received is other than beneficial interests in the assets sold and control over the assets is transferred irrevocably to the buyer. Gains or losses on sales of loans are recognized at the time of sale and are determined by the difference between the net sales proceeds and the allocated basis of the loans sold.

ASB capitalizes mortgage servicing rights (MSRs) when the related loans are sold with servicing rights retained. The total cost of the mortgage loans sold is allocated to the MSRs and the mortgage loans without the MSRs based on their relative fair values at the date of sale. The MSRs are included as a component of gain on sale of loans. The MSRs are amortized in proportion to and over the estimated period of net servicing income. Such amortization is reflected as a component of revenues on the consolidated statements of income.

The MSRs are periodically reviewed for impairment based on their fair value. The fair value of the MSRs, for the purposes of impairment, is measured using a discounted cash flow analysis based on market-adjusted discount rates and anticipated prepayment speeds. Market sources are used to determine prepayment speeds and net cost of servicing per loan.

ASB measures MSR impairment on a disaggregated basis based on certain risk characteristics including loan type and note rate. Impairment losses are recognized through a valuation allowance for each impaired stratum, with any associated provision recorded as a component of loan servicing fees included in ASB's noninterest income.

Allowance for loan losses. ASB maintains an allowance for loan losses that it believes is adequate to absorb losses inherent in the loan portfolio. The level of allowance for loan losses is based on a continuing assessment of existing risks in the loan portfolio, historical loss experience, changes in collateral values and current conditions (e.g., economic conditions, real estate market conditions and interest rate environment). Adverse changes in any of these factors could result in higher charge-offs and provision for loan losses.

For commercial and commercial real estate loans, a risk rating system is used. Loans are rated based on the degree of risk at origination and periodically thereafter, as appropriate. ASB's credit review department performs an evaluation of these loan portfolios to ensure compliance with the internal risk rating system and timeliness of rating changes. A loan is deemed impaired when it is probable that ASB will be unable to collect all amounts due according to the contractual terms of the loan agreement. The measurement of impairment may be based on (i) the present value of the expected future cash flows of the impaired loan discounted at the loan's original effective interest rate, (ii) the observable market price of the impaired loan, or (iii) the fair value of the collateral. For all loans secured by real estate, ASB measures impairment by utilizing the fair value of the collateral; for other loans, discounted cash flows are used to measure impairment. Losses from impairment are charged to the provision for loan losses and included in the allowance for loan losses.

For the residential, consumer and homogeneous commercial loans receivable portfolios, the allowance for loan loss allocations are based on historical loss ratio analyses.

ASB generally ceases the accrual of interest on loans when they become contractually 90 days past due or when there is reasonable doubt as to collectibility. Subsequent recognition of interest income for such loans is generally on the cash method. When, in management's judgment, the borrower's ability to make periodic principal and interest payments resumes, a loan not accruing interest (nonaccrual loan) is returned to accrual status. ASB uses either the cash or cost-recovery method to record cash receipts on impaired loans that are not accruing interest. While the majority of consumer loans are subject to ASB's policies regarding nonaccrual loans, certain past due consumer loans may be charged off upon reaching a predetermined delinquency status varying from 120 to 180 days.

Management believes the allowance for loan losses is adequate. While management utilizes available information to recognize losses on loans, future adjustments may be required from time to time to the allowance for loan losses (e.g. due to changes in economic conditions, particularly in the State of Hawaii) and actual results could differ from management's estimates, and these adjustments and differences could be material.

Real estate acquired in settlement of loans. ASB records real estate acquired in settlement of loans at the lower of cost or fair value less estimated selling expenses. ASB obtains appraisals based on recent comparable sales to assist management in estimating the fair value of real estate acquired in settlement of loans. Subsequent declines in value are charged to expense through a valuation allowance. Costs related to holding real estate are charged to operations as incurred.

Goodwill and other intangibles. Goodwill and intangible assets with indefinite useful lives are tested for impairment at least annually. Intangible assets with definite useful lives are amortized over their respective estimated useful lives to their estimated residual values, and reviewed for impairment in accordance with SFAS No. 144.

Goodwill. ASB's $83.1 million of goodwill, which is the Company's only intangible asset with an indefinite useful life, is tested for impairment annually in the fourth quarter using data as of September 30. For 2006, 2005 and 2004, there has been no impairment of goodwill. The fair value of ASB is estimated by an unrelated third party using a valuation method based on a market approach, which takes into consideration market values of comparable companies, which are publicly traded, and recent transactions of companies in the industry.

Amortized intangible assets.

December 31	2006		2005	
(in thousands)	Gross carrying amount	Accumulated amortization	Gross carrying amount	Accumulated amortization
Core deposit intangibles	$20,276	$18,662	$20,276	$16,932
Mortgage servicing rights	11,695	9,130	11,662	8,650
	$31,971	$27,792	$31,938	$25,582

Changes in the valuation allowance for MSRs were as follows:

(in thousands)	2006	2005	2004
Valuation allowance, January 1	$207	$ 701	$ 2,316
Provision (reversal of allowance)	(74)	(359)	4
Other than temporary impairment	(14)	(135)	(1,619)
Valuation allowance, December 31	$119	$ 207	$ 701

In 2006, 2005 and 2004, aggregate amortization expenses were $2.2 million, $2.4 million and $3.2 million, respectively.

The estimated aggregate amortization expense for ASB's core deposit intangibles and MSRs for 2007, 2008, 2009, 2010 and 2011 is $2.0 million, $0.4 million, $0.3 million, $0.3 million and $0.2 million, respectively.

Core deposit intangibles are amortized each year based on the greater of the actual attrition rate of such deposit base or the applicable rate on the 10-year amortization table. Core deposit intangibles are reviewed for impairment based on their estimated fair value.

ASB capitalizes MSRs acquired through either the purchase or origination of mortgage loans for sale or securitization with servicing rights retained. Changes in mortgage interest rates impact the value of ASB's MSRs. Rising interest rates typically result in slower prepayment speeds in the loans being serviced for others which increases the value of MSRs, whereas declining interest rates typically result in faster prepayment speeds which decreases the value of MSRs and increases the amortization of the MSRs. In 2006, 2005 and 2004, MSRs acquired through the sale or securitization of loans held for sale totaled $0.1 million, $0.1 million, and $0.4 million, respectively. Amortization expense for ASB's MSRs amounted to $0.5 million, $0.7 million, and $1.5 million for 2006, 2005 and 2004, respectively, and are recorded as a reduction in revenues on the consolidated statements of income.

2 • Segment financial information

The electric utility and bank segments are strategic business units of the Company that offer different products and services and operate in different regulatory environments. The accounting policies of the segments are the same as those described in the summary of significant accounting policies, except that income taxes for each segment are calculated on a “stand-alone” basis. HEI evaluates segment performance based on income from continuing operations. The Company accounts for intersegment sales and transfers as if the sales and transfers were to third parties, that is, at current market prices. Intersegment revenues consist primarily of interest and preferred dividends.

Electric utility

HECO and its wholly-owned operating subsidiaries, HELCO and MECO, are electric public utilities in the business of generating, purchasing, transmitting, distributing and selling electric energy on all major islands in Hawaii other than Kauai, and are regulated by the PUC. HECO also owns non-regulated subsidiaries: Renewable Hawaii, Inc. (RHI), which will invest in renewable energy projects, and HECO Capital Trust III, which is an unconsolidated financing entity.

Bank

ASB is a federally chartered savings bank providing a full range of banking services to individual and business customers through its branch system in Hawaii. ASB is subject to examination and comprehensive regulation by the Department of Treasury, Office of Thrift Supervision (OTS) and the Federal Deposit Insurance Corporation (FDIC), and is subject to reserve requirements established by the Board of Governors of the Federal Reserve System. ASB’s insurance product sales activities, including those conducted by ASB’s insurance agency subsidiary, Bishop Insurance Agency of Hawaii, Inc., are subject to regulation by the Hawaii Insurance Commissioner.

Other

“Other” includes amounts for the holding companies and other subsidiaries not qualifying as reportable segments and intercompany eliminations.

As of December 31, 2006, HEI Properties, Inc. (HEIPI) held shares of Hoku Scientific, Inc. (Hoku), a materials science company focused on clean energy technologies. Prior to August 5, 2005, the investment had been accounted for under the cost method. Hoku initiated a public equity offering and shares of Hoku began trading on the Nasdaq Stock Market on August 5, 2005. Since August 5, 2005, Hoku shares have been considered marketable and HEIPI has classified the shares as trading securities, carried at fair value with changes in fair value recorded in earnings. HEIPI began trading Hoku stock in February 2006 when its lock-up agreement expired. In 2006 and 2005, HEIPI recognized a $1.6 million loss (unrealized and realized, net of taxes) and a $2.9 million gain (unrealized, net of taxes), respectively, on the Hoku shares. As of December 31, 2006, HEIPI had sold 33% of its Hoku shares and carried its remaining investment in Hoku shares at $1.2 million. In January 2007, HEIPI sold its remaining investment in Hoku for a net after-tax gain of $0.9 million.

Segment financial information was as follows:

(in thousands)	Electric Utility	Bank	Other	Total
2006				
Revenues from external customers	$2,054,616	$ 408,365	$ (2,077)	$2,460,904
Intersegment revenues (eliminations)	274	–	(274)	–
Revenues	2,054,890	408,365	(2,351)	2,460,904
Depreciation and amortization	138,096	13,175	691	151,962
Interest expense	52,563	146,096	23,115	221,774
Profit (loss)*	121,387	88,558	(38,890)	171,055
Income taxes (benefit)	46,440	32,776	(16,162)	63,054
Income (loss) from continuing operations	74,947	55,782	(22,728)	108,001
Capital expenditures	195,072	14,927	530	210,529
Assets (at December 31, 2006 **)	3,063,134	6,808,499	19,576	9,891,209
2005				
Revenues from external customers	$1,806,198	$ 387,910	$ 21,456	$2,215,564
Intersegment revenues (eliminations)	186	–	(186)	–
Revenues	1,806,384	387,910	21,270	2,215,564
Depreciation and amortization	131,350	10,065	746	142,161
Interest expense	49,408	121,426	25,901	196,735
Profit (loss)*	117,425	104,852	(20,933)	201,344
Income taxes (benefit)	44,623	39,969	(10,692)	73,900
Income (loss) from continuing operations	72,802	64,883	(10,241)	127,444
Capital expenditures	217,609	5,731	335	223,675
Assets (at December 31, 2005 **)	3,081,460	6,835,335	34,782	9,951,577
2004				
Revenues from external customers	$1,550,671	$ 364,284	$ 9,102	$1,924,057
Depreciation and amortization	123,700	17,044	781	141,525
Interest expense	49,588	112,787	27,588	189,963
Profit (loss)*	130,656	99,466	(29,903)	200,219
Income taxes (benefit)	49,479	58,404	(15,403)	92,480
Income (loss) from continuing operations	81,177	41,062	(14,500)	107,739
Capital expenditures	201,236	13,085	333	214,654
Assets (at December 31, 2004 **)	2,879,615	6,766,505	73,137	9,719,257

* Income (loss) from continuing operations before income taxes.
** Includes net assets of discontinued operations.

Intercompany electric sales of the electric utilities to the bank and “other” segments are not eliminated because those segments would need to purchase electricity from another source if it were not provided by consolidated HECO, the profit on such sales is nominal and the elimination of electric sales revenues and expenses could distort segment operating income and net income.

Bank fees that ASB charges the electric utility and “other” segments are not eliminated because those segments would pay fees to another financial institution if they were to bank with another institution, the profit on such fees is nominal and the elimination of bank fee income and expenses could distort segment operating income and net income.

Selected financial information

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income Data

Years ended December 31	2006	2005	2004
(in thousands)			
Revenues			
Operating revenues	$2,050,412	$1,801,710	$1,546,875
Other—nonregulated	4,478	4,674	3,796
	2,054,890	1,806,384	1,550,671
Expenses			
Fuel oil	781,740	639,650	483,423
Purchased power	506,893	458,120	398,836
Other operation	186,449	172,962	157,198
Maintenance	90,217	82,242	77,313
Depreciation	130,164	122,870	114,920
Taxes, other than income taxes	190,413	167,295	143,834
Other – nonregulated	2,296	1,542	1,244
	1,888,172	1,644,681	1,376,768
Operating income from regulated and nonregulated activities	166,718	161,703	173,903
Allowance for equity funds used during construction	6,348	5,105	5,794
Interest and other charges	(53,478)	(50,323)	(50,503)
Allowance for borrowed funds used during construction	2,879	2,020	2,542
Income before income taxes and preferred stock dividends of HECO	122,467	118,505	131,736
Income taxes	46,440	44,623	49,479
Income before preferred stock dividends of HECO	76,027	73,882	82,257
Preferred stock dividends of HECO	1,080	1,080	1,080
Net income for common stock	$ 74,947	$ 72,802	$ 81,177

Consolidated Balance Sheet Data

December 31	2006	2005
(in thousands)		
Assets		
Utility plant, at cost		
Property, plant and equipment	$ 4,038,264	$ 3,782,565
Less accumulated depreciation	(1,558,913)	(1,456,537)
Construction in progress	95,619	147,756
Net utility plant	2,574,970	2,473,784
Regulatory assets	112,349	110,718
Other	375,815	496,958
	$ 3,063,134	$ 3,081,460
Capitalization and liabilities		
Common stock ($6 2/3 par value, authorized 50,000,000 shares. outstanding: 12,805,843 shares)	$ 85,387	$ 85,387
Premium on common stock	299,214	299,214
Retained earnings	700,252	654,686
Accumulated other comprehensive loss	(126,650)	(28)
Common stock equity	958,203	1,039,259
Cumulative preferred stock – not subject to mandatory redemption (authorized 5,000,000 shares, $20 par value (1,114,657 shares outstanding), and 7,000,000 shares,$100 par value (120,000 shares outstanding); dividend rates of 4.25-7.625%)	34,293	34,293
Long-term debt, net	766,185	765,993
Total capitalization	1,758,681	1,839,545
Short-term borrowings from nonaffiliates and affiliate	113,107	136,165
Deferred income taxes	118,055	208,374
Regulatory liabilities	240,619	219,204
Contributions in aid of construction	276,728	256,263
Other	555,944	421,909
	$ 3,063,134	$ 3,081,460

Regulatory assets and liabilities. In accordance with SFAS No. 71, HECO and its subsidiaries' financial statements reflect assets, liabilities, revenues and expenses based on current cost-based rate-making regulations. Their continued accounting under SFAS No. 71 generally requires that rates are established by an independent, third-party regulator; rates are designed to recover the costs of providing service; and it is reasonable to assume that rates can be charged to and collected from customers. Management believes HECO and its subsidiaries' operations currently satisfy the SFAS No. 71 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to income and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, management believes that a material adverse effect on the Company's results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

Regulatory liabilities represent amounts included in rates and collected from ratepayers for costs expected to be incurred in the future. For example, the regulatory liability for cost of removal in excess of salvage value represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire utility plant. Regulatory assets represent deferred costs expected to be fully recovered through rates over PUC authorized periods. Generally, HECO and its subsidiaries do not earn a return on their regulatory assets, however, they have been allowed to accrue and recover interest on their regulatory assets for integrated resource planning costs. Noted in parenthesis are the original PUC authorized amortization or recovery periods and the remaining amortization or recovery periods as of December 31, 2006, if different. Regulatory liabilities were as follows:

December 31	2006	2005
(in thousands)		
Cost of removal in excess of salvage value (1 to 60 years)	$239,049	$217,493
Other (5 years; 1 to 5 years)	1,570	1,711
	$240,619	$219,204

Regulatory assets were as follows:

December 31	2006	2005
(in thousands)		
Income taxes, net (1 to 36 years)	$ 73,178	$ 70,743
Postretirement benefits other than pensions (18 years; 6 years)	10,738	12,528
Unamortized expense and premiums on retired debt and equity issuances (13 to 30 years; 1 to 22 years)	14,909	16,081
Integrated resource planning costs, net (1 year)	4,521	2,395
Vacation earned, but not yet taken (1 year)	5,759	5,669
Other (1 to 20 years)	3,244	3,302
	$112,349	$110,718

Cumulative preferred stock. The cumulative preferred stock of HECO and its subsidiaries is redeemable at the option of the respective company at a premium or par, but none is subject to mandatory redemption.

Major customers. HECO and its subsidiaries received approximately 10%, or $197 million, $176 million and $148 million, of their operating revenues from the sale of electricity to various federal government agencies in 2006, 2005 and 2004, respectively.

Commitments and contingencies

Fuel contracts. HECO and its subsidiaries have contractual agreements to purchase minimum quantities of fuel oil and diesel fuel through December 31, 2014 (at prices tied to the market prices of petroleum products in Singapore and Los Angeles). Based on the average price per barrel as of January 1, 2007, the estimated cost of minimum purchases under the fuel supply contracts is $539 million for 2007, $540 million for 2008, $539 million each year for 2009, 2010 and 2011, and a total of $1.6 billion for the period 2012 through 2014. The actual cost of purchases in 2007 and future years could vary substantially from this estimate as a result of changes in market prices, quantities actually purchased and/or other factors. HECO and its subsidiaries purchased $755 million, $662 million and $490 million of fuel under contractual agreements in 2006, 2005 and 2004, respectively.

Power purchase agreements (PPAs). As of December 31, 2006, HECO and its subsidiaries had six firm capacity PPAs for a total of 540 megawatt (MW) of firm capacity. Purchases from these six IPPs and all other IPPs totaled $507 million, $458 million and $399 million for 2006, 2005 and 2004, respectively. The PUC allows rate recovery for energy and firm capacity payments to IPPs under these agreements. Assuming that each of the agreements remains in place for its current term and the minimum availability criteria in the PPAs are met, aggregate minimum fixed capacity charges are expected to be approximately $118 million in 2007, $119 million in 2008, $116 million in 2009, $118 million in 2010 and 2011 and a total of $1.1 billion in the period from 2012 through 2030.

In general, HECO and its subsidiaries base their payments under the PPAs upon available capacity and energy and they are generally not required to make payments for capacity if the contracted capacity is not available, and payments are reduced, under certain conditions, if available capacity drops below contracted levels. In general, the payment rates for capacity have been predetermined for the terms of the agreements. Energy payments will vary over the terms of the agreements. HECO and its subsidiaries pass on changes in the fuel component of the energy charges to customers through the ECAC in their rate schedules (see “Energy cost adjustment clauses” below). HECO and its subsidiaries do not operate, or participate in the operation of, any of the facilities that provide power under the agreements. Title to the facilities does not pass to HECO or its subsidiaries upon expiration of the agreements, and the agreements do not contain bargain purchase options for the facilities.

Interim increases. On September 27, 2005, the PUC issued an Interim Decision and Order (D&O) granting a general rate increase on Oahu of 4.36%, or $53.3 million (3.33%, or $41.1 million excluding the transfer of certain costs from a surcharge line item on electric bills into base electricity charges). The tariff changes implementing the interim rate increase were effective September 28, 2005.

As of December 31, 2006, HECO and its subsidiaries had recognized $79 million of revenues with respect to interim orders ($14 million related to interim orders regarding certain integrated resource planning costs and $65 million related to the interim order with respect to Oahu’s general rate increase request based on a 2005 test year), which revenues are subject to refund, with interest, if and to the extent they exceed the amounts allowed in final orders.

Energy cost adjustment clauses. On June 19, 2006, the PUC issued an order in HECO's pending rate case based on a 2005 test year, indicating that the record in the pending case has not been developed for the purpose of addressing the factors in Act 162, signed into law by the Governor of Hawaii on June 2, 2006. Act 162 states that any automatic fuel rate adjustment clause requested by a public utility in an application filed with the PUC shall be designed, as determined in the PUC'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. While the PUC already reviews the automatic fuel rate adjustment clause in rate cases, Act 162 requires that these five specific factors be addressed in the record. The PUC's order requested the parties in the rate case proceeding to meet informally to determine a procedural schedule to address the issues relating to HECO's ECAC that are raised by Act 162. The parties in the rate case proceeding are HECO, the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs of the State of Hawaii (Consumer Advocate), and the federal Department of Defense (DOD).

On June 30, 2006, HECO and the Consumer Advocate filed a stipulation requesting that the PUC not review the Act 162 ECAC issues in the pending rate case based on a 2005 test year since HECO's application was filed and the record in the proceeding was completed before Act 162 was signed into law, and the settlement agreement entered into by the parties in the rate case included a provision allowing the existing ECAC to be continued. On August 7, 2006, an amended stipulation was filed in substantially the same form as the June 30, 2006 stipulation, but also included the DOD. Management cannot predict whether the PUC will accept the disposition of the Act 162 issue proposed in the amended stipulation or, if not, the procedural steps or procedural schedule that will be adopted to address the issues that are raised by Act 162 or the timing of the PUC's issuance of a final D&O in HECO's pending rate case based on a 2005 test year.

The ECAC provisions of Act 162 will be reviewed in the HELCO rate case based on a 2006 test year and HECO and MECO rate cases based on 2007 test years.

In the HELCO 2006 test year rate case, the filed testimony of the Consumer Advocate's consultant concluded that HELCO's ECAC provides a fair sharing of the risks of fuel cost changes between HELCO and its ratepayers in a manner that preserves the financial integrity of HELCO without the need for frequent rate filings.

Management cannot predict the ultimate outcome or the effect of these Act 162 issues on the operation of the ECAC as it relates to the electric utilities.

HELCO power situation. In 1991, HELCO began planning to meet increased electric generation demand forecast for 1994. It planned to install at its Keahole power plant two 20 MW combustion turbines (CT-4 and CT-5), followed by an 18 MW heat recovery steam generator (ST-7), at which time these units would be converted to a 56 MW (net) dual-train combined-cycle unit. In January 1994, the PUC approved expenditures for CT-4. In 1995, the PUC allowed HELCO to pursue construction of and commit expenditures for CT-5 and ST-7, but noted that such costs are not to be included in rate base until the project is installed and "is used and useful for utility purposes." As a result of the final resolution of the proceedings described below, CT-4 and CT-5 are now operational, there are no pending lawsuits involving the project, and work on ST-7 is proceeding. In May 2006, HELCO filed a rate increase application based on a 2006 test year seeking to recover, among other things, CT-4 and CT-5 costs.

Historical context. Installation of CT-4 and CT-5 was significantly delayed as a result of land use and environmental permitting delays and related administrative proceedings and lawsuits. However, in 2003, the parties opposing the plant expansion project (other than Waimana Enterprises, Inc. (Waimana), which did not participate in the settlement discussions and opposed the settlement) entered into a settlement agreement with HELCO and several Hawaii regulatory agencies, intended in part to permit HELCO to complete CT-4 and CT-5 (Settlement Agreement). Subsequently, HELCO installed CT-4 and CT-5 and put them into limited commercial operation in May and June 2004, respectively. HELCO met the Board of Land and Natural Resources' (BLNR's) construction deadline of July 31, 2005. Noise mitigation equipment has been installed on CT-4 and CT-5 and additional noise mitigation work is ongoing to ensure compliance with the night-time noise standard applicable to the plant. Currently, HELCO can operate the generating units at Keahole as required to meet its system needs.

Waimana filed four appeals to the Hawaii Supreme Court from judgments of the Third Circuit Court involving (i) vacating a November 2002 Final Judgment which had halted construction, (ii) upholding the BLNR 2003 construction period extension, (iii) upholding the BLNR's approval of a revocable permit allowing HELCO to use brackish well water as the primary source of water for operating the Keahole plant and (iv) upholding the BLNR's approval of the long-term lease allowing HELCO to use brackish well water.

The Hawaii Supreme Court has either dismissed or issued favorable decisions on all four of these appeals.

In addition to the Supreme Court appeals, one Circuit Court matter had remained open, but it was inactive after the mediation that resulted in the Settlement Agreement. With all appeals resolved, the stipulation to dismiss this case was filed on October 5, 2006 and the case was dismissed with prejudice on October 6, 2006. Full implementation of the Settlement Agreement was conditioned on obtaining final dispositions, which have now been obtained, of all litigation pending at the time of the Settlement Agreement.

The Settlement Agreement required HELCO to undertake a number of actions including expediting efforts to obtain the permits and approvals necessary for installation of ST-7 with selective catalytic reduction emissions control equipment, assisting the Department of Hawaiian Home Lands in installing solar water heating in its housing projects, supporting the Keahole Defense Coalition's participation in certain PUC cases, and cooperating with neighbors and community groups (including a Hot Line service). Many of these actions had commenced well before all of the litigation was resolved.

HELCO's plans for ST-7 are progressing. In November 2003, HELCO filed a boundary amendment petition (to reclassify the Keahole plant site from conservation land use to urban land use) with the State of Hawaii Land Use Commission, which boundary amendment was approved in October 2005. In May 2006, HELCO obtained the County of Hawaii rezoning to a "General Industrial" classification, and in June 2006, received approval for a covered source permit amendment to include selective catalytic reduction with the installation of ST-7. Management believes that any other required permits will be obtained and HELCO has commenced engineering, design and certain construction work for ST-7. HELCO's current cost estimate for ST-7 is approximately $92 million, of which approximately $0.8 million has been incurred through December 31, 2006.

CT-4 and CT-5 costs incurred; management's evaluation. As of December 31, 2006, HELCO's capitalized costs incurred in its efforts to put CT-4 and CT-5 into service and to support existing units (excluding costs for pre-air permit facilities) amounted to approximately $110 million, including $43 million for equipment and material purchases, $47 million for planning, engineering, permitting, site development and other costs and $20 million for allowance for funds used during construction (AFUDC) up to November 30, 1998, after which date HELCO has not accrued AFUDC. The $110 million of costs was reclassified from construction in progress to plant and equipment in 2004 ($103 million) and 2005 ($7 million) and depreciated beginning January 1 of the year following the reclassification.

HELCO's electric rates will not change as a result of including CT-4 and CT-5 in plant and equipment unless and until the PUC grants rate relief in the HELCO rate case filed in May 2006 based on a 2006 test year, in part to recover CT-4 and CT-5 costs. At this time, management continues to believe that no adjustment to costs incurred to put CT-4 and CT-5 into service is required as of December 31, 2006. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HELCO may be required to write off a material portion of these costs.

East Oahu Transmission Project (EOTP). HECO transmits bulk power to the Honolulu/East Oahu area over two major transmission corridors (Northern and Southern). HECO had planned to construct a partial underground/partial overhead 138 kilovolt (kV) line from the Kamoku substation to the Pukele substation, which serves approximately 16% of Oahu's electrical load, including Waikiki, in order to close the gap between the Southern and Northern corridors and provide a third transmission line to the Pukele substation. However, in June 2002, an application for a permit which would have allowed construction in the originally planned route through conservation district lands was denied.

HECO continues to believe that the proposed reliability project (the East Oahu Transmission Project) is needed. In December 2003, HECO filed an application with the PUC requesting approval to commit funds (currently estimated at $62 million; see costs incurred below) for a revised EOTP using a 46 kV system. In March 2004, the PUC granted intervenor status to an environmental organization and three elected officials (collectively treated as one party) and a more limited participant status to four community organizations. The environmental review process for the revised EOTP was completed and the PUC issued a Finding of No Significant Impact in April 2005. Subject to obtaining PUC approval and other construction permits, HECO plans to construct the revised project, none of which is in conservation district lands, in two phases. The first phase is currently projected to be completed in 2008 or 2009, subject to the timing of the PUC approval, and the completion date of the second phase is being evaluated.

As of December 31, 2006, the accumulated costs recorded for the EOTP amounted to $30 million, including (i) $12 million of planning and permitting costs incurred prior to the denial in 2002 of the approval necessary for the partial underground/partial overhead 138 kV line, (ii) $5 million of planning and permitting costs incurred after 2002 and (iii) $13 million for AFUDC. In written testimony filed in June 2005, the consultant for the Consumer Advocate contended that HECO should always have planned for a project using only the 46 kV system and recommended that HECO be required to expense the $12 million incurred before 2003, and the related AFUDC of $5 million. In rebuttal testimony filed in August 2005, HECO contested the consultant's recommendation, emphasizing that the originally proposed 138 kV line would have been a more comprehensive and robust solution to the transmission concerns the project addressed. The PUC held an evidentiary hearing on HECO's application in November 2005, and post-hearing briefing was completed in March 2006.

Just prior to the November 2005 evidentiary hearing, the PUC approved that part of a stipulation between HECO and the Consumer Advocate providing that (i) this proceeding should determine whether HECO should be given approval to expend funds for the EOTP, but with the understanding that no part of the EOTP costs may be recovered from ratepayers unless and until the PUC grants HECO recovery in a rate case (which is consistent with other projects) and (ii) the issue as to whether the pre-2003 planning and permitting costs, and related AFUDC, should be included in the project costs is reserved to, and may be raised in, the next HECO rate case (or other proceeding) in which HECO seeks approval to recover the EOTP costs. Management believes no adjustment to project costs is required as of December 31, 2006. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

Environmental regulation. HEI and its subsidiaries are subject to environmental laws and regulations that regulate the operation of existing facilities, the construction and operation of new facilities and the proper cleanup and disposal of hazardous waste and toxic substances.

HECO, HELCO and MECO, like other utilities, periodically identify petroleum or other chemical releases into the environment associated with current operations and report and take action on these releases when and as required by applicable law and regulations. Except as otherwise disclosed herein, the Company believes the costs of responding to its subsidiaries' releases identified to date will not have a material adverse effect, individually or in the aggregate, on the Company's or consolidated HECO's financial statements.

Additionally, current environmental laws may require HEI and its subsidiaries to investigate whether releases from historical operations may have contributed to environmental impacts, and, where appropriate, respond to such releases, even if they were not inconsistent with law or standard industrial practices prevailing at the time when they occurred. Such releases may involve area-wide impacts contributed to by multiple potentially responsible parties.

Honolulu Harbor investigation. In 1995, the Department of Health of the State of Hawaii (DOH) issued letters indicating that it had identified a number of parties, including HECO, who appeared to be potentially responsible for historical subsurface petroleum contamination and/or operated their facilities upon petroleum-contaminated land at or near Honolulu Harbor in the Iwilei district of Honolulu. Certain of the identified parties formed a work group to determine the nature and extent of any contamination and appropriate response actions, as well as identify additional potentially responsible parties (PRPs). The U.S. Environmental Protection Agency (EPA) became involved in the investigation in June 2000. Later in 2000, the DOH issued notices to additional PRPs. The parties in the work group and some of the new PRPs (collectively, the Participating Parties) entered into a joint defense agreement and signed a voluntary response agreement with the DOH. The Participating Parties agreed to fund investigative and remediation work using an interim cost allocation method (subject to a final allocation) and have organized a limited liability company to perform the work.

In 2001, management developed a preliminary estimate of HECO's share of costs for continuing investigative work, remedial activities and monitoring at the Iwilei Unit of approximately $1.1 million (which was expensed in 2001 and of which $0.8 million has been expended through December 31, 2006). Since 2001, subsurface investigation and assessment have been conducted and several preliminary oil removal tasks have been performed at the Iwilei Unit in accordance with notices of interest issued by the EPA and the DOH.

During 2006 and the beginning of 2007, the PRPs developed analyses of various remedial alternatives for two of the four remedial subunits of the Iwilei Unit. The DOH will use the analyses to make a final determination of which remedial alternatives the PRPs will be required to implement. The DOH is scheduled to complete the final remediation determinations for all remedial subunits of the Iwilei Unit by the end of 2007 or first quarter of 2008. HECO management developed an estimate of HECO's share of the costs associated with implementing the PRP recommended remedial approaches for the two subunits covered by the analyses of approximately $1.2 million, (which was expensed in 2006). As of December 31, 2006, the remaining accrual (amounts expensed less amounts expended) related to the Honolulu Harbor investigation was $1.5 million. Because (1) the full scope of additional investigative work, remedial activities and monitoring remain to be determined, (2) the final cost allocation method among the PRPs has not yet been established and (3) management cannot estimate the costs to be incurred (if any) for the sites other than the Iwilei Unit (such as its Honolulu power plant, which is located in the "Downtown" unit of the Honolulu Harbor site), the cost estimate may be subject to significant change and additional material investigative and remedial costs may be incurred.

In 2003, HECO and other Participating Parties with active operations in the Iwilei area investigated their operations to evaluate whether their facilities were active sources of petroleum contamination in the area. HECO's investigation concluded that its facilities were not then releasing petroleum. Routine maintenance and inspections of HECO facilities since then confirm that they are not currently releasing petroleum.

Regional Haze Rule amendments. In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule that require emission controls known as best available retrofit technology (BART) for industrial facilities emitting air pollutants that reduce visibility in National Parks by causing or contributing to regional haze. States must develop BART implementation plans and schedules in accordance with the amended regional haze rule by December 2007. After Hawaii adopts its plan, HECO, HELCO and MECO will evaluate its impacts, if any, on them. If any of the utilities' generating units are ultimately required to install post-combustion control technologies to meet BART emission limits, the resulting capital and operations and maintenance costs could be significant.

Clean Water Act. Section 316(b) of the federal Clean Water Act requires that the EPA ensure that existing power plant cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. Effective September 9, 2004, the EPA issued a rule, which established location and technology-based design, construction and capacity standards for existing cooling water intake structures. These standards applied to HECO's Kahe, Waiau and Honolulu generating stations, unless the utility could demonstrate that at each facility implementation of these standards would result in costs either significantly higher than projected costs the EPA considered in establishing the standards for the facility (cost-cost test) or significantly greater than the benefits of meeting the standards (cost-benefit test). In either case, the EPA would then make a case-by-case determination of an appropriate performance standard. The regulation also would have allowed restoration of aquatic organism populations in lieu of meeting the standards. The rule required covered facilities to demonstrate compliance by March 2008. HECO had retained a consultant that was developing a cost effective compliance strategy and a preliminary assessment of technologies and operational measures under the rule.

On January 25, 2007, the U.S. Circuit Court for the Second Circuit issued a decision that remanded for further consideration and proceedings significant portions of the rule and found other portions of the rule to be impermissible. In particular, the court determined that restoration and the cost-benefit test were impermissible under the Clean Water Act. It also remanded the best technology available determination to permit the EPA to provide a reasoned explanation for its decision or a new determination. It remanded the cost-cost test for the EPA's further consideration based on the best technology available determination and to afford adequate notice. The EPA has yet to announce whether it plans to request a rehearing by the court of appeals or appeal the decision to the U.S. Supreme Court. If it stands, the court's decision reduces the compliance options available to HECO. The EPA has not issued a schedule for rulemaking, which would be necessary to comply with the court's decision. Due to the uncertainties raised by the court's decision as well as the need for further rulemaking by the EPA, HECO management is unable to predict which compliance options, some of which could entail significant capital expenditures to implement, will be applicable to the electric utilities' facilities.

Collective bargaining agreements. As of December 31, 2006, approximately 58% of the electric utilities' employees are members of the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, Unit 8, which is the only union representing employees of the Company. The current collective bargaining and benefit agreements cover a four-year term, from November 1, 2003 to October 31, 2007, and provide for non-compounded wage increases (3% on November 1, 2003; 1.5% on November 1, 2004, May 1, 2005, November 1, 2005 and May 1, 2006; and 3% on November 1, 2006). Negotiations for new agreements are expected to begin in the third quarter of 2007.

Limited insurance. HECO and its subsidiaries purchase insurance coverages to protect themselves against loss of or damage to their properties and against claims made by third-parties and employees. However, the protection provided by such insurance is limited in significant respects and, in some instances, there is no coverage. HECO, HELCO and MECO's overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have a replacement value roughly estimated at $3.5 billion and are uninsured. Similarly, HECO, HELCO and MECO have no business interruption insurance. If a hurricane or other uninsured catastrophic natural disaster should occur, and if the PUC were not to allow the utilities to recover from ratepayers restoration costs and revenues lost from business interruption, their results of operations and financial condition could be materially adversely impacted. Also, certain insurance has substantial "deductibles", limits on the maximum amounts that may be recovered and exclusions or limitations of coverage for claims related to certain perils. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business, each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, HECO, HELCO and MECO could incur losses in amounts that would have a material adverse effect on its results of operations and financial condition.

Selected financial information

American Savings Bank, F.S.B. and Subsidiaries

Consolidated Statements of Income Data

Years ended December 31	2006	2005	2004
(in thousands)			
Interest and dividend income			
Interest and fees on loans	$231,610	$205,084	$184,773
Interest and dividends on investment and mortgage-related securities	117,160	125,924	122,347
	348,770	331,008	307,120
Interest expense			
Interest on deposit liabilities	73,614	52,064	47,184
Interest on other borrowings	72,482	69,362	65,603
	146,096	121,426	112,787
Net interest income	202,674	209,582	194,333
Provision (reversal of allowance) for loan losses	1,400	(3,100)	(8,400)
Net interest income after provision (reversal of allowance) for loan losses	201,274	212,682	202,733
Noninterest income			
Fees from other financial services	26,385	25,790	23,560
Fee income on deposit liabilities	18,779	16,989	17,820
Fee income on other financial products	8,025	9,058	10,184
Gain (loss) on sale of securities	1,735	175	(70)
Other income	4,671	4,890	5,670
	59,595	56,902	57,164
Noninterest expense			
Compensation and employee benefits	68,478	69,082	65,052
Occupancy	18,829	17,055	16,996
Equipment	14,700	13,722	13,756
Services	21,484	15,466	12,863
Data processing	10,164	10,598	11,794
Marketing	5,199	3,816	3,987
Office supplies, printing and postage	4,055	4,440	4,699
Communication	3,335	3,475	2,879
Other expense	26,067	27,029	22,897
	172,311	164,683	154,923
Income before minority interests and income taxes	88,558	104,901	104,974
Minority interests	–	45	97
Income taxes	32,776	39,969	58,404
Income before preferred stock dividends	55,782	64,887	46,473
Preferred stock dividends	–	4	5,411
Net income for common stock	$ 55,782	$ 64,883	$ 41,062

Consolidated Balance Sheet Data

December 31	2006	2005
(in thousands)		
Assets		
Cash and equivalents	$ 172,370	$ 150,130
Federal funds sold	79,671	57,434
Available-for-sale investment and mortgage-related securities	2,367,427	2,629,351
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,780,461	3,566,834
Other	223,666	244,443
Goodwill and other intangibles, net	87,140	89,379
	$6,808,499	$6,835,335
Liabilities and stockholder's equity		
Deposit liabilities–noninterest-bearing	$ 648,915	$ 624,497
Deposit liabilities–interest-bearing	3,926,633	3,932,922
Other borrowings	1,568,585	1,622,294
Other	104,470	98,189
	6,248,603	6,277,902
Common stock	323,154	321,538
Retained earnings	280,046	272,545
Accumulated other comprehensive loss, net of tax benefits	(43,304)	(36,650)
	559,896	557,433
	$6,808,499	$6,835,335

Investment and mortgage-related securities. ASB owns investment securities (federal agency obligations), private-issue mortgage-related securities and mortgage-related securities issued by the Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) and Government National Mortgage Association (GNMA). As of December 31, 2006, ASB's available-for-sale federal agency obligations had contractual maturity dates in 2008. Mortgage-related securities have contractual terms to maturity, but require periodic payments to reduce principal. In addition, expected maturities will differ from contractual maturities because borrowers have the right to prepay the underlying mortgages.

ASB obtains market prices for the investment and mortgage-related securities from a third party financial services provider. The prices of these securities may be influenced by factors such as market liquidity, corporate credit considerations of the underlying collateral, the levels of interest rates, expectations of prepayments and defaults, limited investor base, market sector concerns and overall market psychology. Adverse changes in any of these factors may result in additional losses.

December 31, 2006

					Gross unrealized losses					
					Less than 12 months			12 months or longer		
(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Count	Fair Value	Amount	Count	Fair Value	Amount
Available-for-sale										
Investment securities-federal agency obligations	$ 149,978	$ –	$ (654)	$ 149,324	5	$ 124,842	$(158)	1	$ 24,482	$ (496)
Mortgage-related securities:										
FNMA, FHLMC and GNMA	1,754,154	505	(51,854)	1,702,805	4	4,534	(22)	206	1,654,550	(51,832)
Private issue	522,173	339	(7,214)	515,298	8	102,155	(726)	26	313,879	(6,488)
	$2,426,305	$844	$(59,722)	$2,367,427	17	$231,531	$(906)	233	$1,992,911	$(58,816)

December 31, 2005

					Gross unrealized losses					
					Less than 12 months			12 months or longer		
(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Count	Fair Value	Amount	Count	Fair Value	Amount
Available-for-sale										
Investment securities-federal agency obligation	$ 24,965	$ –	$ (534)	$ 24,431	–	$ –	$ –	1	$ 24,431	$ (534)
Mortgage-related securities:										
FNMA, FHLMC and GNMA	2,230,279	3,482	(57,315)	2,176,446	68	664,606	(9,774)	147	1,385,218	(47,541)
Private issue	434,671	145	(6,342)	428,474	22	262,279	(3,175)	10	125,332	(3,167)
	$2,689,915	$3,627	$(64,191)	$2,629,351	90	$926,885	$(12,949)	158	$1,534,981	$(51,242)

December 31, 2004

					Gross unrealized losses					
					Less than 12 months			12 months or longer		
(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Count	Fair Value	Amount	Count	Fair Value	Amount
Available-for-sale										
Investment securities-federal agency obligation	$ 24,953	$ –	$ (88)	$ 24,865	1	$ 24,865	$ (88)	–	$ –	$ –
Mortgage-related securities:										
FNMA, FHLMC and GNMA	2,544,020	11,558	(19,538)	2,536,040	97	1,345,961	(10,306)	35	389,488	(9,232)
Private issue	393,518	1,063	(2,114)	392,467	9	169,374	(1,199)	13	63,645	(915)
	$2,962,491	$12,621	$(21,740)	$2,953,372	107	$1,540,200	$(11,593)	48	$453,133	$(10,147)

As of December 31, 2006, 2005 and 2004, ASB's investment in stock of the FHLB of Seattle was carried at cost because it can only be redeemed at par and it is a required investment based on measurements of ASB's capital, assets and/or borrowing levels.

In 2006, 2005 and 2004, proceeds from sales of available-for-sale mortgage-related securities were $61 million, $28 million and $45 million resulting in gross realized gains of $1.8 million, $0.2 million and $0.2 million and gross realized losses of $0.1 million, nil and $0.3 million, respectively.

ASB pledged mortgage-related securities with a carrying value of approximately $195 million and $191 million as of December 31, 2006 and 2005, respectively, as collateral to secure public funds and deposits in ASB's treasury, tax, and loan account with the Federal Reserve Bank of San Francisco. As of December 31, 2006 and 2005, mortgage-related securities with a carrying value of $1,035 million and $800 million, respectively, were pledged as collateral for securities sold under agreements to repurchase.

All securities in the ASB portfolio are investment grade bonds issued by FNMA, FHLMC, GNMA, or non-agency issuers. The non-agency bonds are collateralized by mortgage loan pools and utilize credit support structures that provide the securities with an investment grade rating. ASB has evaluated and determined that as of December 31, 2006 and 2005, all securities in the portfolio with unrealized losses are not other-than-temporarily impaired and these losses have not been included in earnings but instead have been included on a net basis in AOCI. Unrealized losses are primarily the result of changes in interest rates and market sentiment regarding specific issuers or sectors. Based on agency guarantees and credit support structures, management expects full payment of principal and interest on all bonds until maturity or call date. Management intends and believes it has the ability to hold all securities with unrealized losses until there is a recovery of fair value up to the amortized cost of its investment.

Loans receivable

December 31	2006	2005
(in thousands)		
Real estate loans		
One-to-four unit residential and commercial	$2,961,880	$2,844,347
Construction and development	260,870	241,311
	3,222,750	3,085,658
Consumer loans	264,537	248,635
Commercial loans	453,151	412,816
	3,940,438	3,747,109
Undisbursed portion of loans in process	(117,226)	(140,273)
Deferred fees and discounts, including net purchase accounting discounts	(22,033)	(22,088)
Allowance for loan losses	(31,228)	(30,595)
Loans held for investment	3,769,951	3,554,153
Loans held for sale	10,510	12,681
	$3,780,461	$3,566,834

As of December 31, 2006, ASB had impaired loans totaling $26.1 million, which consisted of $4.8 million of commercial real estate loans and $21.3 million of commercial loans. As of December 31, 2005, ASB had impaired loans totaling $20.5 million, which consisted of $4.3 million of commercial real estate loans and $16.2 million of commercial loans. As of December 31, 2006 and 2005, impaired loans totaling $0.3 million and $0.3 million, respectively, had related allowances for loan losses of $0.2 million and $0.1 million, respectively. As of December 31, 2006 and 2005, ASB had $25.8 million and $20.2 million of impaired loans, respectively, for which there were no related allowances for loan losses. ASB realized $1.9 million, $1.4 million and $1.3 million of interest income on impaired loans in 2006, 2005 and 2004, respectively. The average balances of impaired loans during 2006, 2005 and 2004 were $22.0 million, $20.8 million and $20.2 million, respectively.

As of December 31, 2006 and 2005, ASB had nonaccrual and renegotiated loans of $8.7 million and $7.3 million, respectively.

ASB realized $0.1 million, $0.1 million and $0.4 million of interest income on nonaccrual loans in 2006, 2005 and 2004, respectively. If these loans would have earned interest in accordance with their original contractual terms ASB would have realized $0.4 million, $0.5 million and $0.6 million in 2006, 2005 and 2004, respectively. ASB had no loans that were 90 days or more past due on which interest was being accrued as of December 31, 2006 and 2005.

As of December 31, 2006 and 2005, commitments not reflected in the consolidated balance sheets consisted of commitments to originate loans, other than the undisbursed portion of loans in process, of $24 million and $76 million, respectively. Commitments to extend credit are agreements to lend to a customer as long as there is no violation of any condition established in the commitments. Commitments generally have fixed expiration dates or other termination clauses and may require payment of a fee. Since certain of the commitments are expected to expire without being drawn upon, the total commitment amounts do not necessarily represent future cash requirements. ASB minimizes its exposure to loss under these commitments by requiring that customers meet certain conditions prior to disbursing funds. The amount of collateral, if any, is based on a credit evaluation of the borrower and may include residential real estate, accounts receivable, inventory, and property, plant, and equipment.

As of December 31, 2006 and 2005, ASB had commitments to sell residential loans of $0.2 million and $2.5 million, respectively. The loans are included in loans held for sale or represent commitments to make loans at an interest rate set prior to funding (rate lock commitments). Rate lock commitments guarantee a specified interest rate for a loan if ASB's underwriting standards are met, but do not obligate the potential borrower. Rate lock commitments on loans intended to be sold in the secondary market are derivative instruments, but have not been designated as hedges. Rate lock commitments are carried at fair value and adjustments are recorded in "Other income," with an offset on the balance sheet in "Other" liabilities. As of December 31, 2006 and 2005, rate lock commitments were made on loans totaling $0.2 million and $0.2 million, respectively. To offset the impact of changes in market interest rates on the rate lock commitments on loans held for sale, ASB utilizes short-term forward sale contracts. Forward sale contracts are also derivative instruments, but have not been designated as hedges, and thus any changes in fair value are also recorded in "Other income," with an offset on the balance sheet in "Other" assets or liabilities. As of December 31, 2006 and 2005, the notional amounts for forward sales contracts were $0.2 million and $2.5 million, respectively. Valuation models are applied using current market information to estimate fair value. For 2006 and 2005, the net loss on derivatives was nil.

As of December 31, 2006 and 2005, ASB had commitments to sell education loans of $10 million.

As of December 31, 2006 and 2005, standby, commercial and banker's acceptance letters of credit totaled $27 million and $25 million, respectively. Letters of credit are conditional commitments issued by ASB to guarantee payment and performance of a customer to a third party. The credit risk involved in issuing letters of credit is essentially the same as that involved in extending loan facilities to customers. ASB holds collateral supporting those commitments for which collateral is deemed necessary. As of December 31, 2006 and 2005, unused lines of credit totaled $973 million and $867 million, respectively.

ASB services real estate loans owned by third parties ($0.3 billion, $0.4 billion and $0.5 billion as of December 31, 2006, 2005 and 2004, respectively), which are not included in the accompanying consolidated financial statements. ASB reports fees earned for servicing loans as income when the related mortgage loan payments are collected and charges loan servicing costs to expense as incurred.

As of December 31, 2006 and 2005, ASB had pledged loans with an amortized cost of approximately $0.9 billion and $1.1 billion, respectively, as collateral to secure advances from the FHLB of Seattle.

As of December 31, 2006 and 2005, the aggregate amount of loans to directors and executive officers of ASB and its affiliates and any related interests (as defined in Federal Reserve Board Regulation O) of such individuals, was $90 million and $104 million, respectively. The $14 million decrease in such loans in 2006 was attributed to closed lines of credit and repayments of $18 million, partly offset by net new loans to new and existing directors and executive officers of $4 million. As of December 31, 2006 and 2005, $70 million and $87 million of the loan balances, respectively, were to related interests of individuals who are directors of ASB. All such loans were made at ASB's normal credit terms except that residential real estate loans and consumer loans to directors and executive officers of ASB were made at preferred employee interest rates. Management believes these loans do not represent more than a normal risk of collection.

Allowance for loan losses. Changes in the allowance for loan losses were as follows:

(dollars in thousands)	2006	2005	2004
Allowance for loan losses, January 1	$30,595	$33,857	$44,285
Provision (reversal of allowance) for loan losses	1,400	(3,100)	(8,400)
Charge-offs, net of recoveries			
Real estate loans	(200)	(459)	(868)
Other loans	967	621	2,896
Net charge-offs	767	162	2,028
Allowance for loan losses, December 31	$31,228	$30,595	$33,857
Ratio of net charge-offs to average loans outstanding	0.02%	<0.01%	0.06%

NM Not meaningful.

Deposit liabilities

December 31	2006		2005	
(dollars in thousands)	Weighted-average stated rate	Amount	Weighted-average stated rate	Amount
Savings	1.03%	$1,569,514	0.63%	$1,723,949
Other checking				
Interest-bearing	0.26	522,442	0.13	573,442
Noninterest-bearing	–	330,346	–	309,172
Commercial checking	–	318,569	–	315,325
Money market	2.07	202,328	1.18	257,144
Term certificates	3.97	1,632,349	3.18	1,378,387
	1.89%	$4,575,548	1.28%	$4,557,419

As of December 31, 2006 and 2005, certificate accounts of $100,000 or more totaled $530 million and $406 million, respectively.

The approximate amounts of term certificates outstanding as of December 31, 2006 with scheduled maturities for 2007 through 2011 were $1,213 million in 2007, $139 million in 2008, $73 million in 2009, $151 million in 2010 and $46 million in 2011.

Interest expense on deposit liabilities by type of deposit was as follows:

Years ended December 31 (in thousands)	2006	2005	2004
Term certificates	$55,466	$40,063	$38,935
Savings	13,316	8,860	6,525
Money market	3,829	2,582	1,448
Interest-bearing checking	1,003	559	276
	$73,614	$52,064	$47,184

Other borrowings

Securities sold under agreements to repurchase.

December 31, 2006 Maturity	Repurchase liability	Weighted-average interest rate	Collateralized by mortgage-related securities–fair value plus accrued interest
(dollars in thousands)			
Overnight	$152,133	4.51%	$ 178,153
1 to 29 days	45,453	4.98	85,922
30 to 90 days	94,638	5.03	178,900
Over 90 days	546,361	3.93	596,510
	$838,585	4.22%	$1,039,485

The securities underlying the agreements to repurchase are book-entry securities and were delivered by appropriate entry into the counterparties' accounts at the Federal Reserve System. Securities sold under agreements to repurchase are accounted for as financing transactions and the obligations to repurchase these securities are recorded as liabilities in the consolidated balance sheets. The securities underlying the agreements to repurchase continue to be reflected in ASB's asset accounts.

The following table sets forth information concerning securities sold under agreements to repurchase, which provided for the repurchase of identical securities:

Years ended December 31	2006	2005	2004
(dollars in millions)			
Amount outstanding as of December 31	$839	$687	$811
Average amount outstanding	$771	$705	$842
Maximum amount outstanding as of any month-end	$839	$828	$990
Weighted-average interest rate as of December 31	4.22%	3.83%	3.44%
Weighted-average interest rate during the year	4.21%	3.50%	2.65%
Weighted-average remaining days to maturity as of December 31	1,047	423	500

Advances from Federal Home Loan Bank.

December 31, 2006	Weighted-average stated rate	Amount
(dollars in thousands)		
Due in		
2007	4.44%	$299,000
2008	5.44	168,000
2009	4.60	163,000
2010	6.03	100,000
2011	–	–
	4.92%	$730,000

As of December 31, 2006, $65 million of fixed rate FHLB advances with a weighted average rate of 6.94% are callable quarterly at par until maturity in 2010.

ASB and the FHLB of Seattle are parties to an Advances, Security and Deposit Agreement (Advances Agreement), which applies to currently outstanding and future advances, and governs the terms and conditions under which ASB borrows and the FHLB of Seattle makes loans or advances from time to time. Under the Advances Agreement, ASB agrees to abide by the FHLB of Seattle's credit policies, and makes certain warranties and representations to the FHLB of Seattle. Upon the occurrence of and during the continuation of an "Event of Default" (which term includes any event of nonpayment of interest or principal of any advance when due or failure to perform any promise or obligation under the Advances Agreement or other credit arrangements between the parties), the FHLB of Seattle may, at its option, declare all indebtedness and accrued interest thereon, including any prepayment fees or charges, to be immediately due and payable. Advances from the FHLB of Seattle are secured by loans and stock in the FHLB of Seattle. ASB is required to obtain and hold a specific number of shares of capital stock of the FHLB of Seattle. ASB was in compliance with all Advances Agreement requirements as of December 31, 2006 and 2005.

Common stock equity. As of December 31, 2006, ASB was in compliance with the minimum capital requirements under OTS regulations. In 1988, HEI agreed with the OTS predecessor regulatory agency that it would contribute additional capital to ASB up to a maximum aggregate amount of approximately $65 million (Capital Maintenance Agreement). As of December 31, 2006, as a result of capital contributions in prior years, HEI's maximum obligation to contribute additional capital under the agreement had been reduced to approximately $28.3 million.

In December 2004, ASB's capital structure changed when ASB redeemed its preferred stock held by HEIDI ($75 million) and HEIDI infused common equity into ASB ($75 million). This change did not affect HEI's remaining maximum obligation to contribute additional capital under the Capital Maintenance Agreement.

The $7 million increase in accumulated other comprehensive loss from December 31, 2005 to December 31, 2006 was primarily due to the effect of applying SFAS No. 158, partly offset by the increase in the market value of the available-for-sale investment and mortgage-related securities. Changes in the market value of mortgage-related securities do not result in a charge to net income in the absence of an "other-than-temporary" impairment in the value of the securities.

5 • Unconsolidated variable interest entities

Trust financing entities. Hawaiian Electric Industries Capital Trust I (the Trust) was a Delaware statutory trust and financing entity, which issued, in 1997, $100 million of 8.36% Trust Originated Preferred Securities to the public. The Trust was a consolidated subsidiary of HEI through December 31, 2003. Since HEI, as the common security holder, did not absorb the majority of the variability of the Trust, HEI was not the primary beneficiary and, in accordance with FIN 46R, did not consolidate the Trust as of January 1, 2004. In March 2004, HEI completed the issuance and sale of 2 million shares of its common stock (pre-split) in a registered public offering. HEI used the net proceeds from the sale, along with other corporate funds, to effect the redemption of the 8.36% Trust Originated Preferred Securities in April 2004. The Trust was dissolved and terminated in 2004.

HECO Capital Trust I (Trust I) was a financing entity, which issued, in 1997, $50 million of 8.05% Cumulative Quarterly Income Preferred Securities, Series 1997 (1997 Trust Preferred Securities) to the public. In March 2004, HECO, HELCO and MECO borrowed the proceeds of the sale of HECO Capital Trust III's 2004 Trust Preferred Securities and, in April 2004, applied the proceeds, along with other corporate funds, to redeem the 1997 Trust Preferred Securities. HECO Capital Trust II (Trust II) was a financing entity, which issued, in 1998, $50 million of 7.30% Cumulative Quarterly Income Preferred Securities, Series 1998 (1998 Trust Preferred Securities) to the public. In April 2004, the electric utilities used funds primarily from short-term borrowings from HEI and from the issuance of commercial paper by HECO to redeem the 1998 Trust Preferred Securities. Trust I and Trust II, each a Delaware statutory trust, were consolidated subsidiaries of HECO through December 31, 2003. Since HECO, as the common security holder, did not absorb the majority of the variability of the trusts, HECO was not the primary beneficiary and, in accordance with FIN 46R, did not consolidate the trusts as of January 1, 2004. Trust I and Trust II were dissolved and terminated in 2004.

HECO Capital Trust III (Trust III) was created and exists for the exclusive purposes of (i) issuing in March 2004 2,000,000 6.50% Cumulative Quarterly Income Preferred Securities, Series 2004 (2004 Trust Preferred Securities) ($50 million aggregate liquidation preference) to the public and trust common securities ($1.5 million aggregate liquidation preference) to HECO, (ii) investing the proceeds of these trust securities in 2004 Debentures issued by HECO in the principal amount of $31.5 million and issued by each of MECO and HELCO in the respective principal amounts of $10 million, (iii) making distributions on the trust securities and (iv) engaging in only those other activities necessary or incidental thereto. The 2004 Trust Preferred Securities are mandatorily redeemable at the maturity of the underlying debt on March 18, 2034, which maturity may be extended to no later than March 18, 2053; and are redeemable at the issuer's option without premium beginning on March 18, 2009. The 2004 Debentures, together with the obligations of HECO, HELCO and MECO under an expense agreement and HECO's obligations under its trust guarantee and its guarantee of the obligations of HELCO and MECO under their respective debentures, are the sole assets of Trust III. Trust III has at all times been an unconsolidated subsidiary of HECO. Since HECO, as the common security holder, does not absorb the majority of the variability of Trust III, HECO is not the primary beneficiary and does not consolidate Trust III in accordance with FIN 46R. Trust III's balance sheet as of December 31, 2006 consisted of $51.5 million of 2004 Debentures; $50.0 million of 2004 Trust Preferred Securities; and $1.5 million of trust common securities. Trust III's income statement for 2006 consisted of $3.4 million of interest income received from the 2004 Debentures; $3.3 million of distributions to holders of the Trust Preferred Securities; and $0.1 million of common dividends on the trust common securities to HECO. So long as the 2004 Trust Preferred Securities are outstanding, HECO is not entitled to receive any funds from Trust III other than pro rata distributions, subject to certain subordination provisions, on the trust common securities. In the event of a default by HECO in the performance of its obligations under the 2004 Debentures or under its Guarantees, or in the event HECO, HELCO or MECO elect to defer payment of interest on any of their respective 2004 Debentures, then HECO will be subject to a number of restrictions, including a prohibition on the payment of dividends on its common stock.

Purchase power agreements. As of December 31, 2006, HECO and its subsidiaries had six purchase power agreements (PPAs) for a total of 540 MW of firm capacity, and other PPAs with smaller IPPs and Schedule Q providers that supplied as-available energy. Approximately 91% of the 540 MW of firm capacity is under PPAs, entered into before December 31, 2003, with AES Hawaii, Inc. (AES Hawaii), Kalaeloa Partners, L.P. (Kalaeloa), Hamakua Energy Partners, L.P. (HEP) and HPOWER. Purchases from all IPPs for 2006 totaled $507 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $133 million, $181 million, $72 million and $44 million, respectively. The primary business activities of these IPPs are the generation and sale of power to HECO and its subsidiaries (and municipal waste disposal in the case of HPOWER). Current financial information about the size, including total assets and revenues, for many of these IPPs is not publicly available.

Under FIN 46R, an enterprise with an interest in a VIE or potential VIE created before December 31, 2003 (and not thereafter materially modified) is not required to apply FIN 46R to that entity if the enterprise is unable to obtain, after making an exhaustive effort, the necessary information. HECO has reviewed its significant PPAs and determined that the IPPs had no contractual obligation to provide such information. In March 2004, HECO and its subsidiaries sent letters to all of their IPPs, except the Schedule Q providers, requesting the information that they need to determine the applicability of FIN 46R to the respective IPP, and subsequently contacted most of the IPPs to explain and repeat its request for information. (HECO and its subsidiaries excluded their Schedule Q providers from the scope of FIN 46R because their variable interest in the provider would not be significant to the utilities and they did not participate significantly in the design of the provider.) Some of the IPPs provided sufficient information for HECO to determine that the IPP was not a VIE, or was either a "business" or "governmental organization" (HPOWER) as defined under FIN 46R, and thus excluded from the scope of FIN 46R. Other IPPs, including the three largest, declined to provide the information necessary for HECO to determine the applicability of FIN 46R, and HECO was unable to apply FIN 46R to these IPPs.

As required under FIN 46R, HECO continued after 2004 its efforts to obtain from the IPPs the information necessary to make the determinations required under FIN 46R. In January 2005, 2006 and 2007, HECO and its subsidiaries again sent letters to the IPPs that were not excluded from the scope of FIN 46R, requesting the information required to determine the applicability of FIN 46R to the respective IPP. All of these IPPs again declined to provide the necessary information, except that Kalaeloa and Kaheawa Wind Power, LLC (KWP) have now provided their information (see below).

If the requested information is ultimately received from the other IPPs, a possible outcome of future analysis is the consolidation of one or more of such IPPs in HECO's consolidated financial statements. The consolidation of any significant IPP could have a material effect on HECO's consolidated financial statements, including the recognition of a significant amount of assets and liabilities, and, if such a consolidated IPP were operating at a loss and had insufficient equity, the potential recognition of such losses. If HECO and its subsidiaries determine they are required to consolidate the financial statements of such an IPP and the consolidation has a material effect, HECO and its subsidiaries would retrospectively apply FIN 46R in accordance with SFAS No. 154, "Accounting Changes and Error Corrections."

Kalaeloa Partners, L.P. In October 1988, HECO entered into a PPA with Kalaeloa Partners, L.P. (Kalaeloa), subsequently approved by the PUC, which provided that HECO would purchase 180 MW of firm capacity for a period of 25 years beginning in May 1991. In October 2004, HECO and Kalaeloa entered into amendments to the PPA, subsequently approved by the PUC, which together effectively increased the firm capacity from 180 MW to 208 MW. The energy payments that HECO makes to Kalaeloa include: 1) a fuel component, with a fuel price adjustment based on the cost of low sulfur fuel oil, 2) a fuel additives cost component, and 3) a non-fuel component, with an adjustment based on changes in the Gross National Product Implicit Price Deflator. The capacity payments that HECO makes to Kalaeloa are fixed in accordance with the PPA.

Kalaeloa is a Delaware limited partnership formed on October 13, 1988 for the purpose of designing, constructing, owning and operating a 200 MW cogeneration facility on Oahu, which includes two 75 MW oil-fired combustion turbines, two waste heat recovery steam generators, a 50 MW turbine generator and other electrical, mechanical and control equipment. The two combustion turbines were upgraded during 2004 resulting in an increase in the facility's nominal output rating to approximately 220 MW. Kalaeloa has a PPA with HECO (described above) and a steam delivery contract with another customer, the term of which coincides with the PPA. The facility has been certified by the Federal Energy Regulatory Commission as a Qualifying Facility under the Public Utility Regulatory Policies Act of 1978 (PURPA).

Pursuant to the provisions of FIN 46R, HECO is deemed to have a variable interest in Kalaeloa by reason of the provisions of HECO's PPA with Kalaeloa. However, management has concluded that HECO is not the primary beneficiary of Kalaeloa because HECO does not absorb the majority of Kalealoa's expected losses nor receive a majority of Kalaeloa's expected residual returns and, thus, HECO has not consolidated Kalaeloa in its consolidated financial statements. A significant factor which affected the level of expected losses HECO would absorb is the fact that HECO's exposure to fuel price variability is limited to the remaining term of the PPA as compared to the facility's remaining useful life. Although HECO absorbs fuel price variability for the remaining term of the PPA, the PPA does not currently expose HECO to losses as the fuel and fuel related energy payments under the PPA have been approved by the PUC for recovery from customers through base electric rates and through HECO's ECAC to the extent the fuel and fuel related energy payments are not included in base energy rates.

Kaheawa Wind Power, LLC. In December 2004, MECO executed a new PPA with Kaheawa Wind Power, LLC (KWP), which completed the installation of a 30 MW windfarm on Maui and began selling power to MECO in June 2006. Management concluded that MECO does not have to consolidate KWP as MECO does not have a variable interest in KWP because the PPA does not require MECO to absorb variability of KWP.

Apollo Energy Corporation. In October 2004, HELCO and Apollo Energy Corporation (Apollo) executed a restated and amended PPA which enables Apollo to repower its 7 MW facility, and install additional capacity, for a total allowed capacity of 20.5 MW (targeted for commercial operation in April 2007). In December 2005, Apollo assigned the PPA to Tawhiri Power LLC (Tawhiri), a subsidiary of Apollo. In February 2007, Tawhiri voluntarily, unilaterally and irrevocably waived and relinquished its right and benefit under the PPA to collect the floor rate for the entire term of the PPA. Based on information available, management concluded that HELCO does not have to consolidate Apollo as HELCO does not have a variable interest in Apollo because the PPA does not require HELCO to absorb any variability of Apollo.

6 • Short-term borrowings

Short-term borrowings as of December 31, 2006 and 2005 consisted of commercial paper issued by HEI and HECO and had weighted-average interest rates of 5.44% and 4.48%, respectively.

As of December 31, 2006, HEI and HECO maintained syndicated credit facilities which totaled $100 million and $175 million, respectively. As of December 31, 2005, HEI and HECO maintained bilateral bank lines of credit which totaled $80 million and $180 million, respectively. None of the facilities are secured. There were no borrowings under these facilities or lines of credit during 2006 or 2005.

Credit agreements. Effective April 3, 2006, HEI entered into a revolving unsecured credit agreement establishing a line of credit facility of $100 million, with a letter of credit sub-facility, expiring on March 31, 2011, with a syndicate of eight financial institutions. Any draws on the facility bear interest, at the option of HEI, at either the "Adjusted LIBO Rate" plus 50 basis points or the greater of (a) the "Prime Rate" and (b) the sum of the "Federal Funds Rate" plus 50 basis points, as defined in the agreement. The annual fee is 10 basis points on the undrawn commitment amount. The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HEI's Senior Debt Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by S&P and Moody's, respectively) would result in a commitment fee increase of 2.5 basis points and an interest rate increase of 10 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1) would result in a commitment fee decrease of 2 basis points and an interest rate decrease of 10 basis points on any drawn amounts. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have a broad "material adverse change" clause. However, the agreement does contain customary conditions which must be met in order to draw on it, such as the accuracy of certain of its representations at the time of a draw and compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HEI). In addition to customary defaults, HEI's failure to maintain its financial ratio, as defined in its agreement, or meet other requirements will result in an event of default. For example, under its agreement, it is an event of default if HEI fails to maintain a nonconsolidated "Capitalization Ratio" (funded debt) of 50% or less (ratio of 28% as of December 31, 2006, as calculated under the agreement) and "Consolidated Net Worth" of $850 million (Net Worth of $1.3 billion as of December 31, 2006, as calculated under the agreement), if there is a "Change in Control" of HEI, if any event or condition occurs that results in any "Material Indebtedness" of HEI being subject to acceleration prior to its scheduled maturity, if any "Material Subsidiary Indebtedness" actually becomes due prior to its scheduled maturity, or if ASB fails to remain well capitalized and to maintain specified minimum capital ratios. HEI's syndicated credit facility is maintained to support the issuance of commercial paper, but may also be drawn to make investments in and advances to its subsidiaries, and for the Company's working capital and general corporate purposes.

Effective April 3, 2006, HECO entered into a revolving unsecured credit agreement establishing a line of credit facility of $175 million with a syndicate of eight financial institutions. The agreement has an initial term which expires on March 29, 2007. On August 30, 2006, HECO filed an application with the PUC requesting approval to maintain the $175 million credit facility for five years, which, if approved by the PUC, will automatically extend the termination date of the credit facility from March 29, 2007 to March 31, 2011. Any draws on the facility bear interest, at the option of HECO, at either the "Adjusted LIBO Rate" plus 40 basis points or the greater of (a) the "Prime Rate" and (b) the sum of the "Federal Funds Rate" plus 50 basis points, as defined in the agreement. The annual fee is 8 basis points on the undrawn commitment amount. The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HECO's Senior Debt Rating (e.g., from BBB+/Baa1 to BBB/Baa2 by S&P and Moody's, respectively) would result in a commitment fee increase of 2 basis points and an interest rate increase of 10 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB+/Baa1 to A-/A3) would result in a commitment fee decrease of 1 basis point and an interest rate decrease of 10 basis points on any drawn amounts. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have a broad "material adverse change" clause. However, the agreement does contain customary conditions that must be met in order to draw on it, such as the accuracy of certain of its representations at the time of a draw and compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HECO, and restricting HECO's ability, as well as the ability of any of its subsidiaries, to guarantee indebtedness of the subsidiaries if such additional debt would cause the subsidiary's "Consolidated Subsidiary Funded Debt to Capitalization Ratio" to exceed 65% (ratios of 47% for HELCO and 43% for MECO as of December 31, 2006, as calculated under the agreement)). In addition to customary defaults, HECO's failure to maintain its financial ratios, as defined in its agreement, or meet other requirements will result in an event of default. For example, under the agreement, it is an event of default if HECO fails to maintain a "Consolidated Capitalization Ratio" (equity) of at least 35% (ratio of 54% as of December 31, 2006, as calculated under the agreement), if HECO fails to remain a wholly-owned subsidiary of HEI or if any event or condition occurs that results in any "Material Indebtedness" of HECO or any of its significant subsidiaries being subject to acceleration prior to its scheduled maturity. HECO's syndicated credit facility is maintained to support the issuance of commercial paper, but it may also be drawn for general corporate purposes and capital expenditures.

7 • Long-term debt

December 31	2006	2005
(dollars in thousands)		
6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004, due 2034 (see Note 5)	$ 51,546	$ 51,546
Obligations to the State of Hawaii for the repayment of special purpose revenue bonds (SPRB) issued on behalf of electric utility subsidiaries		
4.75-4.95%, due 2012-2025	118,500	118,500
5.00-5.50%, due 2014-2032	203,400	203,400
5.65-5.88%, due 2018-2027	266,000	266,000
6.15-6.20%, due 2020-2029	130,000	130,000
	717,900	717,900
Less unamortized discount	(3,261)	(3,453)
	714,639	714,447
HEI medium-term notes 6.55-7.56%, paid in 2006	–	110,000
HEI medium-term notes 6.90-6.93%, due 2007	10,000	10,000
HEI medium-term note 4.00%, due 2008	50,000	50,000
HEI medium-term notes 4.23-6.141%, due 2011	150,000	50,000
HEI medium-term note 7.13%, due 2012	7,000	7,000
HEI medium-term note 5.25%, due 2013	50,000	50,000
HEI medium-term note 6.51%, due 2014	100,000	100,000
	$1,133,185	$1,142,993

As of December 31, 2006, the aggregate principal payments required on long-term debt for 2007 through 2011 are $10 million in 2007, $50 million in 2008, nil in 2009 and 2010 and $150 million in 2011.

Pensions. Substantially all of the employees of HEI and the electric utilities participate in the Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries (HEI/HECO Pension Plan) and substantially all of the employees of ASB and its subsidiaries participate in the American Savings Bank Retirement Plan (ASB Pension Plan and, collectively, Plans). The Plans are qualified, non-contributory defined benefit pension plans and include benefits for union employees determined in accordance with the terms of the collective bargaining agreements between the utilities and their respective unions. The Plans are subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In addition, some current and former executives and directors of HEI and its subsidiaries participate in noncontributory, nonqualified plans (collectively, Supplemental/Excess/Directors Plans). In general, benefits are based on the employees' years of service and compensation.

The Plans and the Supplemental/Excess/Directors Plans were adopted with the expectation that they will continue indefinitely, but the continuation of these plans and the payment of any contribution thereunder is not assumed as a contractual obligation by the participating employers. The Directors' Plan has been frozen since 1996, and no participants have accrued any benefits after that time. The plan will be terminated at the time all remaining benefits have been paid.

Each participating employer reserves the right to terminate its participation in the applicable plans at any time, and HEI and ASB reserve the right to terminate their respective plans at any time. If a participating employer terminates its participation in the Plans, the interest of each affected participant would become 100% vested to the extent funded. Upon the termination of the Plans, assets would be distributed to affected participants in accordance with the applicable allocation provisions of ERISA and any excess assets that exist would be paid to the participating employers. Participants' benefits in the Plans are covered up to certain limits under insurance provided by the Pension Benefit Guaranty Corporation.

The participating employers contribute amounts to a master pension trust for the Plans in accordance with the funding requirements of ERISA and considering the deductibility of contributions under the Internal Revenue Code. The funding of the Plans is based on actuarial assumptions adopted by the Pension Investment Committee administering the Plans on the advice of an enrolled actuary.

To determine pension costs for HEI and its subsidiaries under the Plans and the Supplemental/Excess/Directors Plans, it is necessary to make complex calculations and estimates based on numerous assumptions, including the assumptions identified below.

Postretirement benefits other than pensions. HEI and the electric utilities provide eligible employees health and life insurance benefits upon retirement under the Postretirement Welfare Benefits Plan for Employees of Hawaiian Electric Company, Inc. and participating employers (HECO Benefits Plan). Health benefits are also provided to dependents of eligible retired employees. The contribution for health benefits paid by the participating employers is based on the retirees' years of service and retirement dates. Generally, employees are eligible for these benefits if, upon retirement from active employment, they are eligible to receive benefits from the HEI/HECO Pension Plan.

Among other provisions, the HECO Benefits Plan provides prescription drug benefits for Medicare-eligible participants who retire after 1998. Retirees who are eligible for the drug benefits are required to pay a portion of the cost each month. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the 2003 Act) was signed into law on December 8, 2003. The 2003 Act expanded Medicare to include for the first time coverage for prescription drugs. The 2003 Act provides that persons eligible for Medicare benefits can enroll in Part D, prescription drug coverage, for a monthly premium. Alternatively, if an employer sponsors a retiree health plan that provides benefits determined to be actuarially equivalent to those covered under the Medicare standard prescription drug benefit, the employer will be paid a subsidy of 28 percent of a participant's drug costs between $250 and $5,000 if the participant waives coverage under Medicare Part D.

The HECO Benefits Plan was adopted with the expectation that it will continue indefinitely, but the continuation of the plan and the payment of any contribution thereunder is not assumed as a contractual obligation by the participating employers. Each participating employer reserves the right to terminate its participation in the plan at any time.

SFAS No. 158. In September 2006, the FASB issued 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)," which requires employers to recognize on their balance sheets the funded status of defined benefit pension and other postretirement benefit plans with an offset to AOCI in stockholders' equity (using the projected benefit obligation, rather than the accumulated benefit obligation, to calculate the funded status of pension plans).

By application filed on December 8, 2005 (AOCI Docket), the electric utilities had requested the PUC to permit them to record, as a regulatory asset pursuant to 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. The electric utilities updated their application in the AOCI Docket in November 2006 to take into account SFAS No. 158. 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 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.

The incremental effect of applying SFAS No. 158 on individual line items in the Company's balance sheet as of December 31, 2006 was as follows:

(in thousands)	Before SFAS No. 158 adoption	Pension benefits adjustments	Other benefits adjustments	After SFAS No. 158 adoption
Other assets	$ 395,668	$(103,030)	$ –	$ 292,638
Total assets	9,994,239	(103,030)	–	9,891,209
Other liabilities	392,260	94,658	31,536	518,454
Deferred income taxes	196,083	(77,032)	(12,271)	106,780
Total liabilities	8,724,785	17,626	19,265	8,761,676
Accumulated other comprehensive loss	(35,607)	(120,656)	(19,265)	(175,528)
Total stockholders' equity	1,235,161	(120,656)	(19,265)	1,095,240

Although there is not an immediate impact on net income due to the D&O in the updated AOCI Docket, the electric utilities (as well as HEI) were required by SFAS No. 158 to record substantial charges against stockholder's equity, and the electric utilities' 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 were also adversely affected. These effects could adversely affect security ratings, and increase the difficulty or expense of 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. The electric utilities will also propose to restore equity for all AOCI charges for rate making purposes in their respective rate cases.

Pension and other postretirement benefit plans information. The changes in the obligations and assets of the Company's retirement benefit plans for 2005 and the funded status of these plans and the unrecognized and recognized amounts related to these plans and reflected in the Company's balance sheet as of December 31, 2005 were as follows:

(in thousands)	Pension benefits	Other benefits
Benefit obligation, January 1, 2005	$ 893,638	$200,182
Service cost	29,369	5,248
Interest cost	52,120	11,104
Amendments	123	–
Actuarial (gain) loss	28,422	(17,080)
Benefits paid and expenses	(42,555)	(8,540)
Benefit obligation, December 31, 2005	961,117	190,914
Fair value of plan assets, January 1, 2005	781,758	109,484
Actual return on plan assets	56,621	7,965
Employer contribution (including company payments for nonqualified plans)	14,126	10,716
Benefits paid and expenses	(42,555)	(8,540)
Fair value of plan assets, December 31, 2005	809,950	119,625
Funded status	(151,167)	(71,290)
Unrecognized net actuarial loss	266,784	24,871
Unrecognized net transition obligation	18	21,966
Unrecognized prior service cost (gain)	(4,949)	157
Net amount recognized, December 31, 2005	$ 110,686	$ (24,296)
Amounts recognized in the balance sheet consist of:		
Prepaid benefit cost	$122,206	$ –
Accrued benefit liability	(13,929)	(24,296)
Intangible asset	351	–
Accumulated other comprehensive income	2,058	–
Net amount recognized, December 31, 2005	$110,686	$(24,296)

The changes in the obligations and assets of the Company's retirement benefit plans and the changes in AOCI (gross) for 2006 and the funded status of these plans and amounts related to these plans reflected in the Company's balance sheet as of December 31, 2006 were as follows:

(in thousands)	Pension benefits	Other benefits
Benefit obligation, January 1, 2006	$ 961,117	$190,914
Service cost	32,486	5,099
Interest cost	54,200	10,620
Amendments	4,726	–
Actuarial gain	(21,832)	(5,856)
Benefits paid and expenses	(45,135)	(9,555)
Benefit obligation, December 31, 2006	985,562	191,222
Fair value of plan assets, January 1, 2006	809,950	119,625
Actual return on plan assets	106,702	15,957
Employer contribution	3,022	9,890
Benefits paid and expenses	(44,396)	(9,106)
Fair value of plan assets, December 31, 2006	875,278	136,366
Accrued benefit liability, December 31, 2006	(110,284)	(54,856)
AOCI, January 1, 2006	2,058	–
Recognized during year – net recognized transition obligation	(5)	(3,138)
Recognized during year – prior service (cost)/credit	205	(13)
Recognized during year – net actuarial losses	(12,005)	(412)
Occurring during year – prior service cost	4,726	–
Occurring during year – net actuarial gains	(56,850)	(11,895)
Other adjustments	259,795	46,994
AOCI, December 31, 2006	197,924	31,536
Net actuarial loss	120,812	7,676
Prior service cost (gain)	(19)	87
Net transition obligation	8	11,502
AOCI, net of taxes, December 31, 2006	$ 120,801	$ 19,265

The Company does not expect any plan assets to be returned to the Company during calendar year 2007.

The dates used to determine retirement benefit measurements for the defined benefit plans were December 31 of 2006, 2005 and 2004.

The defined benefit pension plans' accumulated benefit obligations, which do not consider projected pay increases, as of December 31, 2006 and 2005 were $854 million and $806 million, respectively.

The Company has determined the market-related value of retirement benefit plan assets by calculating the difference between the expected return and the actual return on the fair value of the plan assets, then amortizing the difference over future years – 0% in the first year and 25% in years two to five, and finally adding or subtracting the unamortized differences for the past four years from fair value. The method includes a 15% range around the fair value of such assets (i.e., 85% to 115% of fair value). If the market-related value is outside the 15% range, then the amount outside the range will be recognized immediately in the calculation of annual net periodic benefit cost.

A primary goal of the plans is to achieve long-term asset growth sufficient to pay future benefit obligations at a reasonable level of risk. The investment policy target for retirement defined benefit plans reflects the philosophy that long-term growth can best be achieved by prudent investments in equity securities while balancing overall fund volatility by an appropriate allocation to fixed income securities. In order to reduce the level of portfolio risk and volatility in returns, efforts have been made to diversify the plans' investments by: asset class, geographic region, market capitalization and investment style.

The expected long-term rate of return assumption of 8.5% was based on the Plan's target asset allocation and projected asset class returns provided by the plans' actuarial consultant.

The weighted-average asset allocation of retirement defined benefit plans was as follows:

	Pension benefits				Other benefits			
			Investment policy				Investment policy	
December 31	2006	2005	Target	Range	2006	2005	Target	Range
Asset category								
Equity securities	72%	69%	70%	65-75%	71%	68%	70%	65-75%
Fixed income	27	29	30	25-35%	29	31	30	25-35%
Other [1]	1	2	–	–	–	1	–	–
	100%	100%	100%		100%	100%	100%	

[1] Other includes alternative investments, which are relatively illiquid in nature and will remain as plan assets until an appropriate liquidation opportunity occurs.

The Company's current estimate of contributions to the retirement benefit plans in 2007 is $14 million.

As of December 31, 2006, the benefits expected to be paid under the retirement benefit plans in 2007, 2008, 2009, 2010, 2011 and 2012 through 2016 amounted to $57 million, $59 million, $62 million, $64 million, $67 million and $385 million, respectively.

The following weighted-average assumptions were used in the accounting for the plans:

	Pension benefits			Other benefits		
December 31	2006	2005	2004	2006	2005	2004
Benefit obligation						
Discount rate	6.00%	5.75%	6.00%	6.00%	5.75%	6.00%
Expected return on plan assets	8.5	9.0	9.0	8.5	9.0	9.0
Rate of compensation increase	4.2	4.6	4.6	4.2	4.6	4.6
Net periodic benefit cost (years ended)						
Discount rate	5.75	6.00	6.25	5.75	6.00	6.25
Expected return on plan assets	9.0	9.0	9.0	9.0	9.0	9.0
Rate of compensation increase	4.6	4.6	4.6	4.6	4.6	4.6

As of December 31, 2006, the assumed health care trend rates for 2007 and future years were as follows: medical, 10.00%, grading down to 5.00% for 2012 and thereafter; dental, 5.00%; and vision, 4.00%. As of December 31, 2005, the assumed health care trend rates for 2006 and future years were as follows: medical, 10.00%, grading down to 5.00% for 2011 and thereafter; dental, 5.00%; and vision, 4.00%.

The components of net periodic benefit cost were as follows:

	Pension benefits			Other benefits		
Years ended December 31	2006	2005	2004	2006	2005	2004
(in thousands)						
Service cost	$ 32,486	$ 29,369	$ 26,454	$ 5,099	$ 5,248	$ 4,530
Interest cost	54,200	52,120	50,654	10,620	11,104	10,770
Expected return on plan assets	(71,684)	(73,971)	(72,880)	(9,918)	(9,853)	(9,690)
Amortization of unrecognized net (2006) transition obligation	5	5	4	3,138	3,138	3,138
Amortization of net (2006) prior service cost (gain)	(205)	(623)	(587)	13	13	13
Amortization of net actuarial loss	12,005	5,924	1,160	412	442	–
Net periodic benefit cost	$ 26,807	$ 12,824	$ 4,805	$ 9,364	$10,092	$ 8,761

The estimated prior service credit, net actuarial loss and net transition obligation for defined benefits pension plans that will be amortized from AOCI into net periodic pension benefit cost over 2007 are $(0.2) million, $11.4 million and nil, respectively. The estimated prior service cost, net actuarial loss and net transitional obligation for other benefit plans that will be amortized from AOCI into net periodic other than pension benefit cost over 2007 are nil, nil and $3.1 million, respectively.

Of the net periodic pension benefit costs, the Company recorded expense of $21 million, $11 million, $5 million in 2006, 2005 and 2004, respectively, and charged the remaining amounts primarily to electric utility plant. Of the net periodic other than pension benefit costs, the Company expensed $7 million, $8 million and $6 million in 2006, 2005 and 2004, respectively, and charged the remaining amounts primarily to electric utility plant.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for pension plans with an accumulated benefit obligation in excess of plan assets were $19 million, $16 million and nil, respectively, as of December 31, 2006 and $16 million, $14 million and nil, respectively, as of December 31, 2005.

The health care cost trend rate assumptions can have a significant effect on the amounts reported for other benefits. As of December 31, 2006, a one-percentage-point increase in the assumed health care cost trend rates would have increased the total service and interest cost by $0.3 million and the postretirement benefit obligation by $3.6 million, and a one-percentage-point decrease would have reduced the total service and interest cost by $0.3 million and the postretirement benefit obligation by $4.1 million.

9 • Share-based compensation

Under the 1987 Stock Option and Incentive Plan, as amended (SOIP), HEI may issue an aggregate of 9.3 million shares of common stock (4,984,655 shares available for issuance under outstanding and future grants and awards as of December 31, 2006) to officers and key employees as incentive stock options, nonqualified stock options (NQSOs), restricted stock, stock appreciation rights (SARs), stock payments or dividend equivalents. HEI has issued new shares for NQSOs, restricted stock, SARs and dividend equivalents under the SOIP. All information presented has been adjusted for the 2-for-1 stock split in June 2004.

For the NQSOs and SARs, the exercise price of each NQSO or SAR generally equaled the fair market value of HEI's stock on or near the date of grant. NQSOs, SARs and related dividend equivalents issued in the form of stock awarded prior to and through 2004 generally become exercisable in installments of 25% each year for four years, and expire if not exercised ten years from the date of the grant. The 2005 SARs awards, which have a ten year exercise life, generally become exercisable at the end of four years (i.e., cliff vesting) with the related dividend equivalents issued in the form of stock on an annual basis. Accelerated vesting is provided in the event of a change-in-control or upon retirement. NQSOs and SARs compensation expense has been recognized in accordance with the fair value-based measurement method of accounting. The estimated fair value of each NQSO and SAR grant was calculated on the date of grant using a Binomial Option Pricing Model.

Restricted stock grants generally become unrestricted three to five years after the date of grant and restricted stock compensation expense has been recognized in accordance with the fair value-based measurement method of accounting.

The Company recorded share-based compensation expense of $1.6 million in 2006, $3.6 million in 2005 and $1.8 million in 2004. The Company recorded related income tax benefit (including a valuation allowance due to limits on the deductibility of executive compensation) on share-based compensation expense of $0.7 million in 2006, $1.1 million in 2005 and $0.7 million in 2004. The Company has not capitalized any share-based compensation cost.

In place of a SARs grant for 2006, the Company instead awarded restricted stock, as described under "Restricted stock." For all share-based compensation, the estimated forfeiture rate is 1.4%.

Nonqualified stock options

Information about HEI's NQSOs is summarized as follows:

	2006		2005		2004	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	929,000	$19.88	1,122,500	$19.74	1,476,600	$19.02
Granted	–	–	–	–	–	–
Exercised	(269,000)	$20.38	(193,500)	19.07	(348,100)	16.67
Forfeited	–	–	–	–	–	–
Expired	–	–	–	–	(6,000)	19.86
Outstanding, December 31	660,000	$19.68	929,000	$19.88	1,122,500	$19.74
Options exercisable, December 31	581,000	$19.57	651,500	$19.51	568,000	$19.06

(1) Weighted-average exercise price

December 31, 2006		Outstanding			Exercisable		
Year of grant	Range of exercise prices	Number of options	Weighted-average remaining contractual life	Weighted-average exercise price	Number of options	Weighted-average remaining contractual life	Weighted-average exercise price
1998	$ 20.50	6,000	1.3	$20.50	6,000	1.3	$20.50
1999	17.61 - 17.63	65,000	2.5	17.62	65,000	2.5	17.62
2000	14.74	52,000	3.3	14.74	52,000	3.3	14.74
2001	17.96	89,000	4.2	17.96	89,000	4.2	17.96
2002	21.68	150,000	5.2	21.68	150,000	5.2	21.68
2003	20.49	298,000	6.2	20.49	219,000	6.1	20.49
	$14.74 – 21.68	660,000	5.0	$19.68	581,000	4.9	$19.57

As of December 31, 2006, NQSO shares outstanding and NQSO exercisable had an aggregate intrinsic value (including dividend equivalents) of $8.3 million and $7.4 million, respectively.

NQSO activity and statistics are summarized as follows:

($ in thousands, except prices)	2006	2005	2004
Shares vested	198,500	277,000	325,000
Aggregate fair value of vested shares	$916	$1,215	$1,493
Cash received from exercise	$5,481	$3,689	$5,802
Intrinsic value of shares exercised [1]	$2,908	$2,375	$5,719
Tax benefit realized for the deduction of exercises	$965	$518	$531
Dividend equivalent shares distributed under Section 409A	43,265	–	–
Weighted-average Section 409A distribution price	$26.27	–	–
Intrinsic value of shares distributed under Section 409A	$1,137	–	–
Tax benefit realized for Section 409A distributions	$442	–	–

[1] Intrinsic value is the amount by which the fair market value of the underlying stock and the related dividend equivalents exceeds the exercise price of the option.

As of December 31, 2006, there was $0.1 million of total unrecognized compensation cost related to nonvested NQSOs and that cost is expected to be recognized over a weighted average period of four months.

Stock appreciation rights

Information about HEI's SARs is summarized as follows:

	2006		2005		2004	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	879,000	$26.12	349,000	$26.02	–	$ –
Granted	–	–	554,000	26.18	349,000	26.02
Exercised	–	–	(24,000)	26.02	–	–
Forfeited	–	–	–	–	–	–
Expired	–	–	–	–	–	–
Outstanding, December 31	879,000	$26.12	879,000	$26.12	349,000	$26.02
Options exercisable, December 31	399,000	$26.09	81,250	$26.02	–	–

(1) Weighted-average exercise price

December 31, 2006		Outstanding			Exercisable		
Year of grant	Range of exercise prices	Number of shares underlying SARs	Weighted-average remaining contractual life	Weighted-average exercise price	Number of shares underlying SARs	Weighted-average remaining contractual life	Weighted-average exercise price
2004	$ 26.02	325,000	5.1	$26.02	235,000	4.3	$26.02
2005	26.18	554,000	6.5	26.18	164,000	2.4	26.18
	$26.02 –26.18	879,000	6.0	$26.12	399,000	3.5	$26.09

As of December 31, 2006, the SARs outstanding and the SARs exercisable had an aggregate intrinsic value (including dividend equivalents) of $2.2 million and $0.8 million, respectively.

SARs activity and statistics are summarized as follows:

($ in thousands, except prices)	2006	2005	2004
Shares vested	317,750	105,250	–
Aggregate fair value of vested shares	$1,773	$537	–
Cash received from exercise	–	–	–
Intrinsic value of shares exercised [1]	–	$10	–
Tax benefit realized for the deduction of exercises	–	$4	–
Dividend equivalent shares distributed under Section 409A	28,600	–	–
Weighted-average Section 409A distribution price	$26.37	–	–
Intrinsic value of shares distributed under Section 409A	$754	–	–
Tax benefit realized for Section 409A distributions	$293	–	–

1 Intrinsic value is the amount by which the fair market value of the underlying stock and the related dividend equivalents exceeds the exercise price of the option.

As of December 31, 2006, there was $1.1 million of total unrecognized compensation cost related to SARs and that cost is expected to be recognized over a weighted average period of 2.2 years.

No SARs were granted in 2006. The weighted-average fair value of each of the SARs granted during 2005 and 2004 was $5.82 and $5.11 (at grant date), respectively. For 2005 and 2004, the weighted-average assumptions used to estimate fair value include: risk-free interest rate of 4.1% and 3.4%, expected volatility of 18.1% and 16.7%, expected dividend yield of 5.9% and 5.8%, respectively, term of 10 years and expected life of 4.5 years for both years. The weighted-average fair value of the SARs grant is estimated on the date of grant using a Binomial Option Pricing Model. See below for discussion of 2005 grant modification. The expected volatility is based on historical price fluctuations. The Company believes that historical volatility is appropriate based upon the Company's business model and strategies.

Section 409A modification

As a result of the changes enacted in Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), for 2006 a total of 71,865 dividend equivalent shares for NQSO and SAR grants were distributed to SOIP participants, including those that retired during 2006. Section 409A, which amended the rules on deferred compensation, required the Company to change the way certain affected dividend equivalents are paid in order to avoid significant adverse tax consequences to the SOIP participants. Generally dividend equivalents subject to Section 409A would be paid within 2½ months after the end of the calendar year. However, upon retirement, an SOIP participant may elect to take distributions of dividend equivalents subject to Section 409A at the time of retirement rather than at the end of the calendar year.

As noted above, in December 2005, to comply with Section 409A, HEI modified certain provisions pertaining to the dividend equivalent rights attributable to the outstanding grants of NQSOs and SARs held by 40 employees under the 1987 HEI Stock Option and Incentive Plan, as amended. The modifications apply to the NQSOs granted in 2001, 2002, and 2003 and the SARs granted in 2004 and 2005 and in general accelerate the distribution of dividend equivalent shares earned after 2004. When a share-based award is modified, the Company recognizes the incremental compensation cost, which is measured as the excess, if any, of the fair value of the modified award over the fair value of the original award immediately before its terms are modified.

The assumptions used to estimate fair value at the time of the Section 409A modification for the 2005 and 2004 SARs include: risk-free interest rate of 4.4%, expected volatility of 14.9%, original term of 10 years and expected dividend yield of 4.6%. The expected life used at the time of modification was 4.2 and 3.8 years for 2005 and 2004, respectively. As of December 7, 2005, the fair value of modified 2005 SARs, the fair value of original 2005 SARs and the additional compensation cost to be recognized per grant was $5.07, $4.95 and $0.12, respectively. As of December 7, 2005, the fair value of modified 2004 SARs, the fair value of original 2004 SARs and the additional compensation cost to be recognized per grant was $4.34, $4.25 and $0.09, respectively. The additional compensation cost for the Section 409A modification was not material.

Restricted stock

Information about HEI's restricted stock grants are summarized as follows:

	2006		2005		2004	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	41,000	$23.50	34,000	$22.58	28,000	$22.17
Granted	60,800	$26.32	9,000	26.06	6,000	24.48
Restrictions ended	(10,000)	$20.65	(2,000)	19.29	–	–
Forfeited	–	–	–	–	–	–
Outstanding, December 31	91,800	$25.68	41,000	$23.50	34,000	$22.58

(1) Weighted-average price per share at grant date

The grant date fair value of a grant of a restricted stock share is the closing price of HEI common stock on the date of grant.

In 2006, 2005 and 2004, restricted stock granted had a fair market value of $1.6 million, $0.2 million and $0.1 million, respectively. In 2006, 2005 and 2004, restricted stock vested had a fair market value of $0.2 million, nil and nil, respectively. The tax benefit realized for the tax deductions from restricted stock dividends were $0.1 million for 2006 and immaterial for 2005 and 2004.

As of December 31, 2006, there was $1.5 million of total unrecognized compensation cost related to nonvested restricted stock. The cost is expected to be recognized over a period of 3.3 years

10 • Income taxes

The components of income taxes attributable to income from continuing operations were as follows:

Years ended December 31	2006	2005	2004
(in thousands)			
Federal			
Current	$65,501	$66,819	$42,142
Deferred	(9,372)	(1,226)	15,670
Deferred tax credits, net	(1,259)	(1,351)	(1,446)
	54,870	64,242	56,366
State			
Current	5,848	3,586	32,809
Deferred	(1,468)	2,619	(1,875)
Deferred tax credits, net	3,804	3,453	5,180
	8,184	9,658	36,114
	$63,054	$73,900	$92,480

A reconciliation of the amount of income taxes computed at the federal statutory rate of 35% to the amount provided in the Company's consolidated statements of income was as follows:

Years ended December 31	2006	2005	2004
(in thousands)			
Amount at the federal statutory income tax rate	$59,869	$70,471	$70,077
Increase (decrease) resulting from:			
State income taxes, net of effect on federal income taxes and excluding cumulative bank franchise taxes through December 31, 2003	5,319	6,278	3,133
Cumulative bank franchise taxes through December 31, 2003	–	–	20,340
Other, net	(2,134)	(2,849)	(1,070)
	$63,054	$73,900	$92,480

The tax effects of book and tax basis differences that give rise to deferred tax assets and liabilities were as follows:

December 31	2006	2005
(in thousands)		
Deferred tax assets		
Cost of removal in excess of salvage value	$ 93,014	$ 85,292
Contributions in aid of construction and customer advances	38,582	38,406
Allowance for loan losses	12,202	11,886
Net unrealized losses on available-for-sale mortgage-related securities	23,416	24,087
Retirement Benefits in AOCI	89,394	804
Other	23,543	22,588
	280,151	183,063
Deferred tax liabilities		
Property, plant and equipment	277,508	271,949
Leveraged leases	6,542	8,444
Retirement Benefits	27,886	38,545
Goodwill	12,531	10,652
Regulatory assets, excluding amounts attributable to property, plant and equipment	28,495	27,588
FHLB stock dividend	20,552	20,552
Other	13,417	13,330
	386,931	391,060
Net deferred income tax liability	$106,780	$207,997

The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Based upon historical taxable income, projections for future taxable income and available tax planning strategies, management believes it is more likely than not the Company will realize substantially all of the benefits of the deferred tax assets.

In the first quarter of 2005, the Company recorded a $2 million reserve, net of taxes, for interest the Company might incur on the potential taxes related to the disputed timing of dividend income recognition because of a change in ASB's 2000 and 2001 tax year-ends. In the second quarter of 2005, the Company made a $30 million deposit primarily to stop the further accrual of interest on the potential taxes related to the disputed timing of dividend income recognition. Also in the second quarter of 2005, $1 million of income taxes and interest payable, net of taxes, were reversed due to the resolution of other audit issues with the IRS. In the fourth quarter of 2005, additional IRS audit issues were resolved, resulting in the reversal of $1 million of interest expense, net of taxes.

As of December 31, 2006, $1 million, net of tax effects, was accrued for potential tax issues and related interest. Although not probable, adverse developments on potential tax issues could result in additional charges to net income in the future. Based on information currently available, the Company believes it has adequately provided for potential income tax issues with federal and state tax authorities and related interest, and that the ultimate resolution of tax issues for all open tax periods will not have a material adverse effect on its results of operations, financial condition or liquidity.

ASB state franchise tax dispute and settlement. In 1998, ASB formed a subsidiary, ASB Realty Corporation, which elected to be taxed as a real estate investment trust (REIT). This reorganization had reduced Hawaii bank franchise taxes as a result of ASB taking a dividends received deduction on dividends paid to it by ASB Realty Corporation. The State of Hawaii Department of Taxation (DOT) challenged ASB's position on the dividends received deduction and issued notices of tax assessment for 1999 through 2001. ASB filed an appeal with the State Board of Review, First Taxation District (Board), which issued its decision in favor of the DOT. ASB filed a notice of appeal with the Hawaii Tax Appeal Court, which issued its decision in favor of the DOT in June 2004. As a result of the decision, ASB recorded a cumulative after-tax charge to net income in the second quarter of 2004 of $24 million ($21 million for the bank franchise taxes and $3 million for interest). ASB appealed the decision to the Hawaii Supreme Court, which appeal was dismissed as part of a settlement on December 31, 2004. ASB agreed to settle its dispute with the DOT and close the tax years 1999 through 2004 (relating to the financial performance of ASB for the years 1998 through 2003) for purposes of audit, examination, assessment, refund and judicial review. Under the terms of the settlement, ASB agreed to pay the DOT $12 million, in addition to $17 million previously paid under protest, dismiss its appeal to the Hawaii Supreme Court and not take the dividends received deduction in future years. As a result, ASB recognized $3 million in additional net income in the fourth quarter of 2004, representing a partial reversal of the $24 million previously charged against net income. ASB Realty Corporation was dissolved in the second quarter of 2005, with substantially all of its assets being distributed to ASB.

11 • Cash flows

Supplemental disclosures of cash flow information. In 2006, 2005 and 2004, the Company paid interest to non-affiliates amounting to $214 million, $192 million and $185 million, respectively.

In 2006, 2005 and 2004, the Company paid income taxes amounting to $69 million, $45 million and $42 million, respectively.

Supplemental disclosures of noncash activities. Under the HEI Dividend Reinvestment and Stock Purchase Plan (DRIP), common stock dividends reinvested by shareholders in HEI common stock in noncash transactions amounted to $5 million in 2004. Since March 2004, HEI has been satisfying the requirements of the HEI DRIP and the Hawaiian Electric Industries Retirement Savings Plan (HEIRSP) by acquiring for cash its common shares through open market purchases rather than the issuance of additional shares. On December 15, 2006, however, the HEI Board of Directors determined that the common stock requirements for the HEI DRIP and HEIRSP will be satisfied by issuance of new HEI shares, commencing in March 2007.

In 2006, 2005 and 2004, other noncash increases in common stock for director and officer compensatory plans were $3 million, $5 million and $3 million, respectively.

In 2006, 2005 and 2004, HECO and its subsidiaries capitalized as part of the cost of electric utility plant an allowance for equity funds used during construction amounting to $6 million, $5 million and $6 million, respectively.

In 2006, 2005 and 2004, the estimated fair value of noncash contributions in aid of construction amounted to $14 million, $12 million and $5 million, respectively.

In 2004, ASB financed $6 million of sales of real estate acquired in settlement of loans.

In 2006, the Company completed the settlement of net taxes and interest due to the IRS for tax years 1994 through 2002. In a non-cash transaction in 2006, a $30 million deposit made by the Company in 2005 with the IRS was applied to the net liabilities of $10 million for tax years 1994 through 2002 and $18 million for tax year 2005 with an immaterial net income impact. The remaining $2 million of the 2005 deposit was refunded to the Company.

Revised cash flows from discontinued operations. From December 31, 2005, the Company will separately disclose the operating, investing and financing portions of the cash flows attributable to its discontinued operations, which were previously reported on a combined basis as a single amount.

12 • Regulatory restrictions on net assets

As of December 31, 2006, HECO and its subsidiaries could not transfer approximately $431 million of net assets to HEI in the form of dividends, loans or advances without PUC approval.

ASB is required to file a notice with the OTS 30 days prior to making any capital distribution to HEI. Generally, the OTS may disapprove or deny ASB’s notice of intention to make a capital distribution if the proposed distribution will cause ASB to become undercapitalized, or the proposed distribution raises safety and soundness concerns, or the proposed distribution violates a prohibition contained in any statute, regulation, or agreement between ASB and the OTS. As of December 31, 2006, ASB could transfer approximately $172 million of net assets to HEI in the form of dividends and still maintain its “well-capitalized” position.

HEI management expects that the regulatory restrictions will not materially affect the operations of the Company nor HEI’s ability to pay common stock dividends.

13 • Significant group concentrations of credit risk

Most of the Company's business activity is with customers located in the State of Hawaii. Most of ASB's financial instruments are based in the State of Hawaii, except for the investment and mortgage-related securities it owns. Substantially all real estate loans receivable are secured by real estate in Hawaii. ASB's policy is to require mortgage insurance on all real estate loans with a loan to appraisal ratio in excess of 80% at origination. As of December 31, 2006, ASB's private-issue mortgage-related securities represented whole or participating interests in pools of mortgage loans collateralized by real estate in the U.S. As of December 31, 2006, various securities rating agencies rated the private-issue mortgage-related securities held by ASB as investment grade.

14 • Discontinued operations

HEI Power Corp. (HEIPC). In 2001, the HEI Board of Directors adopted a formal plan to exit the international power business (engaged in by HEIPC and its subsidiaries, the HEIPC Group). HEIPC management has carried out a program to dispose of all of the HEIPC Group's remaining projects and investments. Accordingly, the HEIPC Group (other than HEI Investment, Inc. (HEIII)) has been reported as a discontinued operation in the Company's consolidated statements of income. HEIPC was dissolved in December 2006. Prior to the dissolution, HEIPC transferred its ownership interests in HEIII to HEI and HEI Diversified, Inc. (HEIDI).

China project. In 1998 and 1999, the HEIPC Group acquired what became a 75% interest in a joint venture, Baotou Tianjiao Power Co., Ltd., formed to construct, own and operate a 200 MW (net) coal-fired power plant to be located in Inner Mongolia. The project received approval from both the national and Inner Mongolia governments. However, the Inner Mongolia Power Company, which owns and operates the electricity grid in Inner Mongolia, caused a delay of the project by failing to enter into a satisfactory interconnection arrangement with the joint venture. The HEIPC Group determined that a satisfactory interconnection arrangement could not be obtained and did not proceed with the project. In the third quarter of 2001, the HEIPC Group wrote off its remaining investment of approximately $24 million in the project. In 2004, the HEIPC Group negotiated with various government agencies a partial recovery of its interest in the China joint venture in the amount of $3 million and recorded a gain, net of income taxes, of $2 million. The HEIPC Group pursued recovery of a significant portion of its losses through arbitration of its claims under a political risk insurance policy. In 2005, the arbitration panel issued its decision denying HEIPC's claims for recovery of losses under the political risk insurance policy.

Philippines investment. In 1998 and 1999, the HEIPC Group invested $10 million to acquire shares in Cagayan Electric Power & Light Co., Inc. (CEPALCO), an electric distribution company in the Philippines. The HEIPC Group recognized impairment losses of approximately $3 million in 2001 and $5 million in 2003 to adjust this investment to its estimated net realizable value at the time of approximately $7 million and $2 million, respectively. In the first quarter of 2004, the HEIPC Group sold HEIPC Philippine Development, LLC, the HEIPC Group company that held an interest in CEPALCO, for a nominal gain.

Summary financial information for the discontinued operations of the HEIPC Group is as follows:

Years ended December 31	2006	2005	2004
(in thousands)			
Disposal			
Gain (loss), including a provision of $1 million for losses from operations during phase-out period in 2006, 2005 and 2004	$ –	$(1,237)	$2,878
Income tax benefits (income taxes)	–	482	(965)
Gain (loss) on disposal	$ –	$ (755)	$1,913

As of December 31, 2006, the remaining net assets of the discontinued international power operations amounted to $2 million (included in "Other" assets) and consisted primarily of deferred taxes receivable.

15 • Fair value of financial instruments

The Company used the following methods and assumptions to estimate the fair value of each applicable class of financial instruments for which it is practicable to estimate that value:

Cash and equivalents and federal funds sold. The carrying amount approximated fair value because of the short maturity of these instruments.

Investment and mortgage-related securities. Fair value was based on market prices obtained from a third party financial services provider.

Loans receivable. For certain homogenous categories of loans, such as residential real estate loans, an asset/liability simulation model was used to estimate fair value. Whenever possible, observable market prices for securities backed by similar loans were used as benchmarks to calibrate the model. The fair value of other types of loans was estimated by discounting the future cash flows using the current rates at which similar loans would be made to borrowers with similar credit ratings and for the same remaining maturities.

Deposit liabilities. The fair value of demand deposits, savings accounts, and money market deposits was the amount payable on demand at the reporting date. The fair value of fixed-maturity certificates of deposit was estimated by discounting the future cash flows using the rates currently offered for deposits of similar remaining maturities.

Other bank borrowings. Fair value was estimated by discounting the future cash flows using the current rates available for borrowings with similar terms and remaining maturities.

Long-term debt. Fair value was obtained from a third party financial services provider based on the current rates offered for debt of the same or similar remaining maturities.

Off-balance sheet financial instruments. The fair value of loans serviced for others was estimated as the net present value of expected net income streams generated from servicing residential mortgage loans for others. The fair value of commitments to originate loans and unused lines of credit was estimated based on the primary market prices of new commitments and new lines of credit. The change in current primary market prices provided the estimate of the fair value of these commitments and unused lines of credit. The fair values of other off-balance sheet financial instruments (letters of credit) were estimated based on the fees currently charged to enter into similar agreements, taking into account the remaining terms of the agreements. Fair value of HECO-obligated preferred securities of trust subsidiaries was based on quoted market prices.

The estimated fair values of certain of the Company's financial instruments were as follows:

December 31	2006		2005	
(in thousands)	Carrying or notional amount	Estimated fair value	Carrying or notional amount	Estimated fair value
Financial assets				
Cash and equivalents	$ 177,630	$ 177,630	$ 151,513	$ 151,513
Federal funds sold	79,671	79,671	57,434	57,434
Available-for-sale investment and mortgage-related securities	2,367,427	2,367,427	2,629,351	2,629,351
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764	97,764	97,764
Loans receivable, net	3,780,461	3,739,223	3,566,834	3,534,583
Financial liabilities				
Deposit liabilities	4,575,548	4,557,418	4,557,419	4,532,420
Other bank borrowings	1,568,585	1,566,571	1,622,294	1,617,198
Long-term debt	1,133,185	1,170,657	1,142,993	1,185,174
Off-balance sheet items				
Loans serviced for others	323,631	4,218	358,565	4,611
HECO-obligated preferred securities of trust subsidiary	50,000	50,800	50,000	51,400

As of December 31, 2006 and 2005, loan commitments and unused lines and letters of credit had carrying amounts of $1.1 billion and $1.1 billion and the estimated fair value was $0.1 million and $0.6 million, respectively.

Limitations. The Company makes fair value estimates at a specific point in time, based on relevant market information and information about the financial instrument. These estimates do not reflect any premium or discount that could result if the Company were to sell its entire holdings of a particular financial instrument at one time. Because no market exists for a significant portion of the Company's financial instruments, fair value estimates cannot be determined with precision. Changes in assumptions could significantly affect the estimates.

Fair value estimates are provided for certain financial instruments without attempting to estimate the value of anticipated future business and the value of assets and liabilities that are not considered financial instruments. In addition, the tax ramifications related to the realization of the unrealized gains and losses could have a significant effect on fair value estimates and have not been considered.

16 • Quarterly information (unaudited)

Selected quarterly information was as follows:

(in thousands, except per share amounts)	Quarters ended March 31	June 30	Sept. 30	Dec. 31	Years ended December 31
2006					
Revenues [1, 2]	$574,962	$604,969	$673,894	$607,079	$2,460,904
Operating income [1, 2]	69,151	60,729	66,356	43,160	239,396
Net income (loss) [1, 2]	32,337	27,224	32,323	16,117	108,001
Basic earnings (loss) per common share [3]	0.40	0.34	0.40	0.20	1.33
Diluted earnings (loss) per common share [4]	0.40	0.33	0.40	0.20	1.33
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [5]					
High	27.26	27.92	28.94	28.18	28.94
Low	25.71	25.69	26.07	26.50	25.69
2005					
Revenues	$472,628	$522,262	$595,915	$624,759	$2,215,564
Operating income [6]	56,671	61,449	77,239	76,063	271,422
Net income (loss) [6]					
Continuing operations	24,095	28,335	37,490	37,524	127,444
Discontinued operations	–	(755)	–	–	(755)
	24,095	27,580	37,490	37,524	126,689
Basic earnings (loss) per common share [3]					
Continuing operations	0.30	0.35	0.46	0.46	1.58
Discontinued operations	–	(0.01)	–	–	(0.01)
	0.30	0.34	0.46	0.46	1.57
Diluted earnings (loss) per common share [4]					
Continuing operations	0.30	0.35	0.46	0.46	1.57
Discontinued operations	–	(0.01)	–	–	(0.01)
	0.30	0.34	0.46	0.46	1.56
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [5]					
High	29.79	27.45	28.76	28.50	29.79
Low	24.60	24.69	26.21	25.50	24.60

1 For 2006, amounts include interim rate relief for HECO.

2 The fourth quarter of 2006 includes an electric utility adjustment for quarterly rate schedule tariff reconciliation that relates to prior quarters.

3 The quarterly basic earnings (loss) per common share are based upon the weighted-average number of shares of common stock outstanding in each quarter.

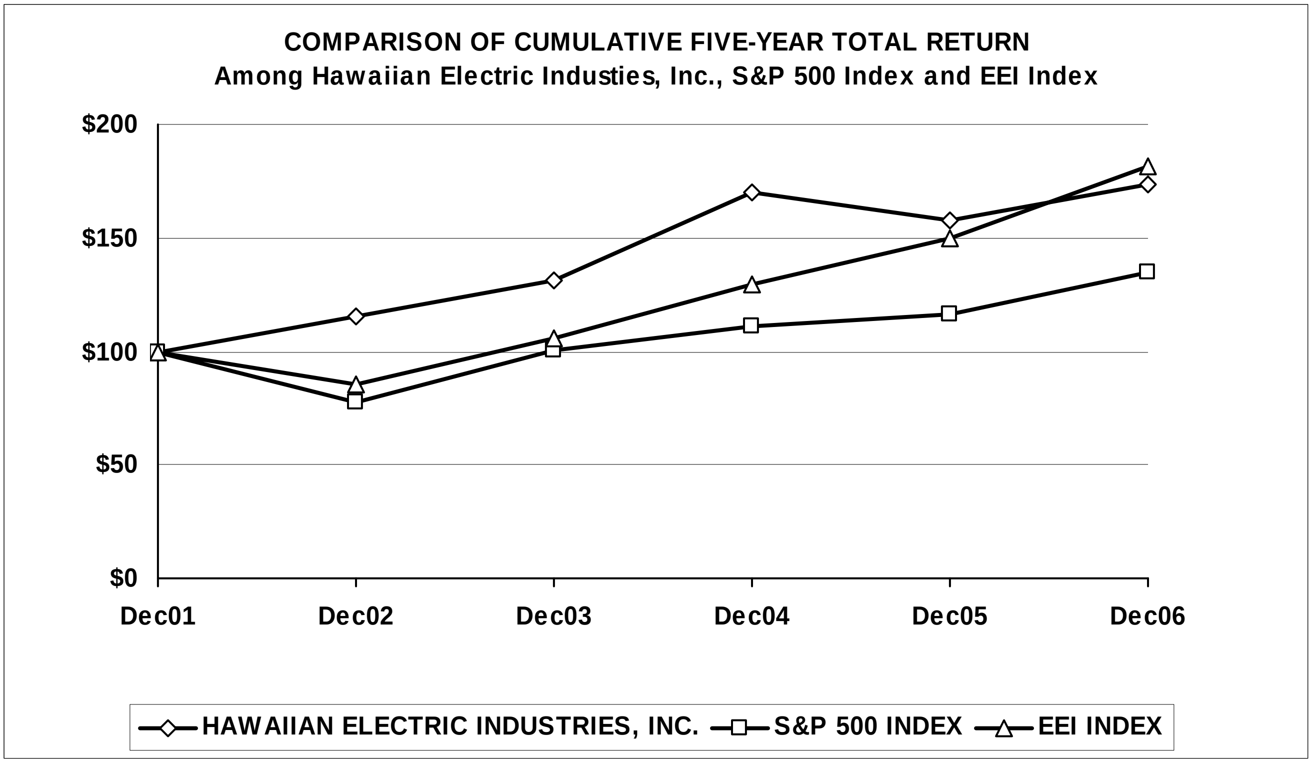
4 The quarterly diluted earnings (loss) per common share are based upon the weighted-average number of shares of common stock outstanding in each quarter plus the dilutive incremental shares at quarter end.

5 Market prices of HEI common stock (symbol HE) shown are as reported on the NYSE Composite Tape.

6 For 2005, amounts for the fourth quarter include interim rate relief for HECO and a $9 million net gain on the sale of an interest in a trust that is the owner/lessor of a 60% interest in a electric generating plant in Georgia.

Shareholder Performance Graph

The graph below compares the cumulative total shareholder return on HEI Common Stock against the cumulative total return of companies listed on Standard & Poor's 500 Stock Index and the Edison Electric Institute (EEI) Index of Investor-Owned Electric Companies (64 companies were included as of December 31, 2006). The graph is based on the market price of common stock for all companies in the indexes at December 31 each year and assumes that $100 was invested on December 31, 2001 in HEI Common Stock and the common stock of all companies in the indexes and that dividends were reinvested.



HEI Directors

Jeffrey N. Watanabe, 64 (1)*
Chairman
Hawaiian Electric Industries, Inc.
Senior Partner
Watanabe Ing & Komeiji LLP
(private law firm)

Constance H. Lau, 54 (1)*
President and
Chief Executive Officer
Hawaiian Electric Industries, Inc.
Chairman
Hawaiian Electric Company, Inc.
Chairman, President and
Chief Executive Officer
American Savings Bank, F.S.B.

Don E. Carroll, 65 (3)*
Retired Chairman
Oceanic Cablevision
(cable television broadcasting)

Shirley J. Daniel, Ph.D., 53 (2)*
Professor of Accountancy
University of Hawaii-Manoa
(higher education)

Admiral Thomas B. Fargo,
USN (Retired), 58 (2)*
President, Trex Enterprises Corporation
(high-technology R&D)
Former Commander of the
U.S. Pacific Command

Victor Hao Li, S.J.D., 65 (3)*
Co-chairman
Asia Pacific Consulting Group
(international business consultant)

Bill D. Mills, 55 (1, 3, 4)
Chairman
The Mills Group
(real estate development)

A. Maurice Myers, 66 (3)
Retired Chairman, President and
Chief Executive Officer
Waste Management, Inc.
(environmental services)

Diane J. Plotts, 71 (1, 2, 3)*
Business Advisor

James K. Scott, Ed.D., 55 (2)*
President
Punahou School
(private education)

Kelvin H. Taketa, 52 (4)*
President and Chief Executive Officer
Hawaii Community Foundation
(statewide charitable foundation)

Barry K. Taniguchi, 59 (2)*
President and Chief Executive Officer
KTA Super Stores
(retail super markets-island of Hawaii)

Committees of the Board of Directors

(1) Executive:
Jeffrey N. Watanabe, Chairman
(2) Audit:
Diane J. Plotts, Chairman
(3) Compensation:
Bill D. Mills, Chairman
(4) Nominating & Corporate Governance:
Kelvin H. Taketa, Chairman

Information as of February 28, 2007.

* Also member of one or more subsidiary and/or advisory boards.

HEI Executive Officers and Subsidiary Presidents

Constance H. Lau, 54
President and Chief Executive Officer
Hawaiian Electric Industries, Inc.
Chairman
Hawaiian Electric Company, Inc.
Chairman, President and
Chief Executive Officer
American Savings Bank, F.S.B.
1984

Andrew I.T. Chang, 67
Vice President–Government Relations
1985

Curtis Y. Harada, 51
Controller
1989

Warren H.W. Lee, 59
President
Hawaii Electric Light Company, Inc.
1972

T. Michael May, 60
President and Chief Executive Officer
Hawaiian Electric Company, Inc.
1992

Edward L. Reinhardt, 54
President
Maui Electric Company, Limited
1986

Patricia U. Wong, 50
Vice President–Administration and
Corporate Secretary
1990

Eric K. Yeaman, 39
Financial Vice President, Treasurer
and Chief Financial Officer
2003

Information as of February 28, 2007.
Year denotes year of first employment by the company.

Shareholder Information

CORPORATE HEADQUARTERS

Hawaiian Electric Industries, Inc.
900 Richards Street,
Honolulu, Hawaii 96813
Telephone: 808-543-5662

Mailing address: P. O. Box 730
Honolulu, Hawaii 96808-0730

NEW YORK STOCK EXCHANGE

Common stock symbol: HE
Trust preferred securities symbol: HEPrU (HECO)

SHAREHOLDER SERVICES

P. O. Box 730
Honolulu, Hawaii 96808-0730
Telephone: 808-532-5841
Toll Free: 866-672-5841
Facsimile: 808-532-5868
E-mail: invest@hei.com
Office hours: 7:30 a.m. to 3:00 p.m. H.S.T.

Correspondence about common stock and utility preferred stock ownership, dividend payments, transfer requirements, changes of address, lost stock certificates, duplicate mailings and account status may be directed to shareholder services.

A copy of the 2006 Form 10-K Annual Report for Hawaiian Electric Industries, Inc. and Hawaiian Electric Company, Inc., including financial statements and schedules, may be obtained from HEI upon written request without charge from shareholder services at the above address or through HEI's website.

WEBSITE

Internet users can access information about HEI and its subsidiaries at http://www.hei.com.

DIVIDENDS AND DISTRIBUTIONS

Common stock quarterly dividends are customarily paid on or about the 10th of March, June, September and December to shareholders of record on the dividend record date.

Quarterly distributions on trust preferred securities are paid by HECO Capital Trust III, an unconsolidated financing subsidiary of HECO, on or about March 31, June 30, September 30 and December 31 to holders of record on the business day before the distribution is paid.

Utility company preferred stock quarterly dividends are paid on the 15th of January, April, July and October to preferred shareholders of record on the 5th of these months.

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

Any individual of legal age or any entity may buy HEI common stock at market prices directly from the Company. The minimum initial investment is $250. Additional optional cash investments may be as small as $25. The annual maximum investment is $120,000. After your account is open, you may reinvest all of your dividends to purchase additional shares, or elect to receive some or all of your dividends in cash. You may instruct the Company to electronically debit a regular amount from a checking or savings account. The Company also can deposit dividends automatically to your checking or savings account. A prospectus describing the plan may be obtained through HEI's website or by contacting shareholder services.

ANNUAL MEETING

Tuesday, April 24, 2007, 9:30 a.m.
American Savings Bank Tower, 1001 Bishop Street
8th Floor, Room 805, Honolulu, Hawaii 96813

Please direct inquiries to:
Patricia U. Wong,
Vice President-Administration and Corporate Secretary
Telephone: 808-543-7900, Facsimile: 808-543-7523

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP
Pauahi Tower, 1001 Bishop Street – Suite 2100
Honolulu, Hawaii 96813
Telephone: 808-531-7286

INSTITUTIONAL INVESTOR AND SECURITIES ANALYST INQUIRIES

Please direct inquiries to:
Suzy P. Hollinger
Manager, Treasury and Investor Relations
Telephone: 808-543-7385
E-mail: shollinger@hei.com

TRANSFER AGENTS

Common stock and utility company preferred stock:
Shareholder Services

Common stock only:
Continental Stock Transfer & Trust Company
17 Battery Place
New York, New York 10004
Telephone: 212-509-4000
Facsimile: 212-509-5150

Trust preferred securities:
Contact your investment broker for information on transfer procedures.

OTHER INFORMATION

The Company has included in its 2006 Form 10-K annual report certifications pursuant to Section 13a-14 of the Securities Exchange Act of 1934 of the Chief Executive Officer (CEO) and the Chief Financial Officer of the Company as Exhibits 31.1 and 31.2, respectively. The Company has submitted to the New York Stock Exchange a certification, dated May 25, 2006, of the CEO certifying that she is not aware of any violation by the Company of the New York Stock Exchange corporate governance listing standards.