Hawaiian Electric Industries, Inc.

2005 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;
- global developments, including the effects of terrorist acts, the war on terrorism, continuing U.S. presence in Iraq and Afghanistan and potential conflict or crisis with North Korea;
- the timing and extent of changes in interest rates;
- 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;
- demand for services and market acceptance risks;
- increasing competition in the electric utility and banking industries (e.g., increased self-generation of electricity may have an adverse impact on HECO's revenues and increased price competition for deposits, or an outflow of deposits to alternative investments, may have an adverse impact on American Savings Bank, F.S.B.'s (ASB's) cost of funds);
- capacity and supply constraints or difficulties, especially if generating units (utility-owned or independent power producer (IPP)-owned) fail or measures such as demand-side management (DSM), distributed generation (DG), combined heat and power (CHP) or other firm capacity supply-side resources fall short of achieving their forecasted benefits or are otherwise insufficient to reduce or meet peak demand;
- increased risk to generation reliability as generation reserve margins on Oahu are lower than considered desirable;
- fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses;
- the ability of IPPs to deliver the firm capacity anticipated in their power purchase agreements (PPAs);
- the ability of the electric utilities to negotiate, periodically, favorable fuel supply and collective bargaining agreements;
- new technological developments that could affect the operations and prospects of HEI and its subsidiaries (including HECO and its subsidiaries and ASB and its subsidiaries) or their competitors;
- federal, state and international governmental and regulatory actions, such as changes in laws, rules and regulations applicable to HEI, HECO and their subsidiaries (including changes in taxation, environmental laws and regulations and governmental fees and assessments); decisions by the Public Utilities Commission of the State of Hawaii (PUC) in rate cases and other proceedings and by other agencies and courts on land use, environmental and other permitting issues; required corrective actions, restrictions and penalties (that may arise with respect to environmental conditions, 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 continued regulatory accounting under Statement of Financial Accounting Standards (SFAS) No. 71 (Accounting for the Effects of Certain Types of Regulation), and the possible effects of applying Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R (Consolidation of Variable Interest Entities) and Emerging Issues Task Force (EITF) Issue No. 01-8 (Determining Whether an Arrangement Contains a Lease) to power purchase arrangements with independent power producers;
- the effects of changes by securities rating agencies in their ratings of the securities of HEI and HECO and the results of financing efforts;
- faster than expected loan prepayments that can cause an acceleration of the amortization of premiums on loans and investments and the impairment of mortgage servicing rights of ASB;
- changes in ASB's loan portfolio credit profile and asset quality which may increase or decrease the required level of allowance for loan losses;
- the final outcome of tax positions taken by HEI, HECO and their subsidiaries;
- the ability of consolidated HEI to generate capital gains and utilize capital loss carryforwards on future tax returns;
- the risks of suffering losses and incurring liabilities that are uninsured; and
- other risks or uncertainties described elsewhere in this report and in other periodic reports (e.g., "Item 1A. Risk Factors" in the Company's Annual Report on Form 10-K) previously and subsequently filed by HEI and/or HECO with the Securities and Exchange Commission (SEC).

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

Selected Financial Data

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2005	2004	2003	2002	2001
(dollars in thousands, except per share amounts)					
Results of operations					
Revenues	$ 2,215,564	$ 1,924,057	$ 1,781,316	$ 1,653,701	$ 1,727,277
Net income (loss)					
Continuing operations	$ 127,444	$ 107,739	$ 118,048	$ 118,217	$ 107,746
Discontinued operations	(755)	1,913	(3,870)	–	(24,041)
	$ 126,689	$ 109,652	$ 114,178	$ 118,217	$ 83,705
Basic earnings (loss) per common share					
Continuing operations	$ 1.58	$ 1.36	$ 1.58	$ 1.63	$ 1.60
Discontinued operations	(0.01)	0.02	(0.05)	–	(0.36)
	$ 1.57	$ 1.38	$ 1.53	$ 1.63	$ 1.24
Diluted earnings per common share	$ 1.56	$ 1.38	$ 1.52	$ 1.62	$ 1.23
Return on average common equity-continuing operations *	10.5%	9.4%	11.1%	12.0%	12.2%
Return on average common equity	10.4%	9.5%	10.7%	12.0%	9.5%
Financial position **					
Total assets	$ 9,951,577	$ 9,719,257	$ 9,307,700	$ 9,039,121	$ 8,663,417
Deposit liabilities	4,557,419	4,296,172	4,026,250	3,800,772	3,679,586
Securities sold under agreements to repurchase	686,794	811,438	831,335	667,247	683,180
Advances from Federal Home Loan Bank	935,500	988,231	1,017,053	1,176,252	1,032,752
Long-term debt, net	1,142,993	1,166,735	1,064,420	1,106,270	1,145,769
HEI- and HECO-obligated preferred securities of trust subsidiaries	–	–	200,000	200,000	200,000
Preferred stock of subsidiaries – not subject to mandatory redemption	34,293	34,405	34,406	34,406	34,406
Stockholders' equity	1,216,630	1,210,945	1,089,031	1,046,300	929,665
Common stock					
Book value per common share **	$ 15.02	$ 15.01	$ 14.36	$ 14.21	$ 13.06
Market price per common share					
High	29.79	29.55	24.00	24.50	20.63
Low	24.60	22.96	19.10	17.28	16.78
December 31	25.90	29.15	23.69	21.99	20.14
Dividends per common share	1.24	1.24	1.24	1.24	1.24
Dividend payout ratio	79%	90%	81%	76%	100%
Dividend payout ratio-continuing operations	78%	91%	78%	76%	78%
Market price to book value per common share **	172%	194%	165%	155%	154%
Price earnings ratio ***	16.4x	21.4x	15.0x	13.5x	12.6x
Common shares outstanding (thousands) **	80,983	80,687	75,838	73,618	71,200
Weighted-average	80,828	79,562	74,696	72,556	67,508
Shareholders ****	35,645	35,292	34,439	34,901	37,387
Employees **	3,383	3,354	3,197	3,220	3,189

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

** At December 31.

*** 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 March 1, 2006, HEI had 35,624 registered shareholders and participants.

The Company discontinued its international power operations in 2001. See Note 14, "Discontinued operations," of the "Notes to Consolidated Financial Statements." Also see "Commitments and contingencies" in Note 3 of the "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), supplies power to 93% of the Hawaii electric public utility market. 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 2005, income from continuing operations was $127 million, compared to $108 million in 2004. Basic earnings per share from continuing operations were $1.58 per share in 2005, up 16% from $1.36 per share in 2004 due primarily to a 2004 after-tax charge of $20 million, or $0.25 per share, as a result of a June 2004 tax ruling and subsequent settlement (see “Bank franchise taxes” sections below). Also impacting results in 2005 were lower electric utility earnings, partly offset by $8 million higher net gains on investments and lower financing costs in the “other” segment. The Company’s operations will be 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 a forecasted 3.5% in 2005 and is expected to grow by a forecasted 2.8% in 2006.

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, 2005 was 4.8%. HEI’s Board believes that HEI should achieve a 65% payout ratio 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 2005, 2004 and 2003 were 79%, 90% and 81% (payout ratios of 78%, 91% and 78% based on income from continuing operations), respectively. The high payout ratio for 2004 was primarily due to the 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 forecast by the DBEDT to be a moderate 3.0% in 2006.

It was a record year for tourism in Hawaii with visitor days exceeding the 2004 record by 6.6%. In 2005, visitor expenditures were $11.8 billion, which is an 8.7% increase over 2004. State economists expect continued growth in 2006 with projected increases of 3.1% in visitor days and 4.6% 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. After five years of increases, real estate prices climbed again in 2005, resulting in $6 billion in total dollar residential resale volumes on Oahu, a 25.8% increase over 2004.

The construction industry continues to remain healthy indicated by a 28.1% increase in building permits in 2005 compared with 2004. Local economists forecast contracting receipts to grow by 5% in 2006.

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 prices of electricity on usage and (2) interest rates because of their potential impact on ASB's earnings, HEI's and HECO's cost of capital, pension costs and HEI's stock price. Crude oil prices rose considerably during 2005 as strong demand from the U.S. and China and geopolitical uncertainty continued. Futures prices began 2005 near $27 per barrel and spiked to a high of $69.81 per barrel in August 2005 in the wake of Hurricane Katrina. Prices moved down in the last quarter of the year as regional production in the Gulf was restored. More recently, however, prices are climbing due to political tension and uncertainty in oil producing countries such as Iran and Nigeria. On February 3, 2006, crude oil futures closed at $65.37 per barrel.

For most of 2005, long-term interest rates fluctuated in the 4.0% to 4.5% trading range and the short-end of the yield curve continued to increase. This resulted in a flattening yield curve throughout the year which is indicative of a difficult earning environment for ASB. As of December 31, 2005, the yield curve was inverted with a spread between the 10-year and 2-year Treasuries of (0.02)%, compared to the yield curve as of December 31, 2004 with a spread of 1.16%.

Results of Operations

(dollars in millions, except per share amounts)		2005	% change		2004	% change		2003
Revenues	$	2,216	15	$	1,924	8	$	1,781
Operating income		271	–		271	3		264
Income from continuing operations	$	128	18	$	108	(9)	$	118
Loss from discontinued operations		(1)	NM		2	NM		(4)
Net income	$	127	16	$	110	(4)	$	114
Electric utility	$	73	(10)	$	81	3	$	79
Bank		65	58		41	(27)		56
Other		(10)	NM		(14)	NM		(17)
Income from continuing operations	$	128	18	$	108	(9)	$	118
Basic earnings (loss) per share								
Continuing operations	$	1.58	16	$	1.36	(14)	$	1.58
Discontinued operations		(0.01)	NM		0.02	NM		(0.05)
	$	1.57	14	$	1.38	(10)	$	1.53
Dividends per share	$	1.24	–	$	1.24	–	$	1.24
Weighted-average number of common shares outstanding (millions)		80.8	2		79.6	7		74.7
Dividend payout ratio		79%			90%			81%
Dividend payout ratio – continuing operations		78%			91%			78%

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 the “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 the “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 and including additional bank franchise taxes in prior periods as if the Company had not taken a dividends received deduction on income from its real estate investment trust (REIT) subsidiary. 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 accounting principles generally accepted in the United States of America (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		2005		2004		2003
(dollars in thousands, except per share amounts)						
Income from continuing operations	$	127,444	$	107,739	$	118,048
Basic earnings per share - continuing operations	$	1.58	$	1.36	$	1.58
Cumulative bank franchise taxes, net of taxes, through December 31, 2003	$	–	$	20,340	$	–
Additional bank franchise taxes, net of taxes (if recorded in prior periods)	$	–	$	–	$	(3,793)
As adjusted						
Income from continuing operations	$	127,444	$	128,079	$	114,255
Basic earnings per share - continuing operations	$	1.58	$	1.61	$	1.53
Return on average common equity [1]		10.5%		11.2%		10.9%

[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 (pension and other postretirement benefits)

The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of 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 2005, 2004 and 2003 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 benefits 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 considers the Moody's Daily Long-Term Corporate Bond Aa Yield Average (which was 5.41% as of December 31, 2005 compared to 5.66% as of December 31, 2004) and changes in this rate from period to period. In addition, the plans' actuarial consultant prepared a 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, 2005, which supports the 5.75% discount rate adopted as of December 31, 2005. 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 2005, the Company's retirement benefit plans' assets generated a total return, net of investment management fees, of 7.2%, resulting in realized and unrealized gains of $65 million, compared to $82 million for 2004 and $154 million for 2003. The market value of the retirement benefit plans' assets as of December 31, 2005 was $931 million. The Company made cash contributions to the retirement benefit plans totaling $25 million in 2005, $37 million in 2004 and $48 million in 2003. Contributions are expected to total $14 million in 2006 ($11 million by the utilities and $3 million by ASB), but actual contributions may differ. Fluctuations in actual equity market returns as well as changes in general interest rates will result in changes in the market value of plan assets and may result in increased or decreased retirement benefits costs and contributions in future periods.

Based on various assumptions in Note 8 of the "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 minimum pension liability; 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, December 31		Retirement benefits expense, net of income tax benefits Years ended December 31				Retirement benefits paid and expenses Years ended December 31		
(dollars in millions)	2005	2004	(Estimated) 2006 [1]	2005 [2]	2004 [2]	2003 [2]	2005	2004	2003
Consolidated HEI	$(1)	$(1)	$18	$11	$7	$12	$51	$49	$45
Consolidated HECO	–	–	14	8	4	9	50	47	43
ASB	–	–	3	2	2	3	1	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, 2006).

2 Does not include impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003. See "Recent accounting pronouncements and interpretations" in Note 1 of the "Notes to Consolidated Financial Statements."

If the Company and consolidated HECO are required to record significant charges to AOCI (and the prepaid pension assets that the electric utilities have been allowed to include in their rate bases for ratemaking purposes are eliminated) in the future, the electric utilities' returns on average rate base (RORs) could increase and if the utilities exceeded the RORs found by the PUC to be reasonable, the rates the electric utilities are allowed to charge could be impacted, which may ultimately result in reduced revenues and lower earnings. In December 2005, the electric utilities submitted a request to the PUC for approval to record and include in rate base the amount that would otherwise be charged to AOCI and reduce stockholder's equity (see Note 8 of the "Notes to Consolidated Financial Statements"). If the relief requested from the PUC is not granted and the electric utilities are required to record significant charges to AOCI, the Company's and consolidated HECO's financial ratios may deteriorate, which could result in security ratings downgrades and difficulty (or greater expense) in obtaining future financing. There also may be possible financial covenant violations (although there are no advances currently outstanding under any credit facility subject to financial covenants) as certain bank lines of credit of the Company and HECO require that HECO maintain a minimum ratio of consolidated equity to consolidated capitalization, excluding short-term borrowings, of 35% (actual ratio of 56% as of December 31, 2005); the Company maintain a consolidated net worth, exclusive of intangible assets, of at least $900 million (actual net worth, exclusive of intangible assets, of $1.1 billion as of December 31, 2005); and HEI, on a non-consolidated basis, maintain a ratio of indebtedness to capitalization of not more than 50% (actual ratio of 27% as of December 31, 2005).

The following tables reflect the sensitivities of the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) as of December 31, 2005, and the sensitivity of 2006 net income, associated with a change in certain actuarial assumptions by the indicated basis points and constitute "forward-looking statements." Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption as well as a related change in the other postretirement benefits contributions to the applicable retirement benefits plan.

Actuarial assumption	Change in assumption in basis points	Impact on PBO/APBO	Impact on 2006 net income
(dollars in millions)			
Pension benefits			
Discount rate	+/– 50	$(63)/$71	$ 3/$(4)
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/(5)	(1)/1
Rate of return on plan assets	+/– 50	NA	– /(–)

NA Not applicable.

Baseline assumptions: 5.75% discount rate; 9% asset return rate; 10% medical trend rate for 2006, grading down to 5% for 2011 and thereafter; 5% dental trend rate; and 4% vision trend rate.

"Other" segment

(dollars in millions)	2005	% change	2004	% change	2003
Revenues [1]	$ 21	134	$ 9	(32)	$ 13
Operating income (loss)	5	NM	(8)	(38)	(6)
Net loss	(10)	NM	(14)	NM	(17)

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 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. The "other" business segment also includes results of operations of financing entities formed to effect the issuance of 8.36% Trust Originated Preferred Securities that were redeemed in April 2004: Hawaiian Electric Industries Capital Trust I and its subsidiary (HEI Preferred Funding, LP), which were deconsolidated on January 1, 2004, dissolved in April 2004 and terminated in December 2004, and Hycap Management, Inc. (which is in dissolution). The first seven months of 2003 also include the results of operations for ProVision Technologies, Inc., a company formed to sell, install, operate and maintain on-site power generation equipment and auxiliary appliances in Hawaii and the Pacific Rim, which was sold for a nominal loss in July 2003; and two other inactive subsidiaries, HEI Leasing, Inc. and HEI District Cooling, Inc., which were dissolved in October 2003.

- 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 and $2.3 million in 2003, primarily from leveraged leases.

- HEIPI recorded net income of $3.5 million in 2005, net losses of $0.9 million in 2004 and net income of $0.1 million in 2003, which amounts include income and losses from and/or writedowns of venture capital investments. In 2005, HEIPI recognized a $4.6 million unrealized gain ($2.9 million after-tax) on its investment in Hoku Scientific, Inc. (Hoku), a Hawaii fuel cell technology startup company that completed its initial public offering and became a public company in August 2005. Also in 2005, HEIPI recorded lower writedowns of another venture capital investment in a nonpublic company. As of December 31, 2005, HEIPI's venture capital investments (including Hoku) amounted to $6.9 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 and the other subsidiaries' revenues in 2003 include $9.3 million from the settlement of lawsuits in the fourth quarter of 2003.

HEI Corporate operating, general and administrative expenses (including labor, employee benefits, incentive compensation, charitable contributions, legal fees, consulting, rent, supplies and insurance) were $14.8 million in 2005, $14.9 million in 2004 and $15.9 million in 2003. The slightly higher expenses in 2003 were due in part to legal expenses incurred in connection with lawsuits and the settlement of lawsuits. HEI Corporate and the other subsidiaries' net loss was $30.0 million in 2005, $15.4 million in 2004 and $19.5 million in 2003, the majority of which is comprised of financing costs. The loss for 2005 includes most of the $5 million of income taxes on the $14 million gain on sale by HEIII described above. Also, the results for 2005 did not include $5.4 million of dividends on ASB preferred stock held by HEIDI, as it had in 2004 and 2003, 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 2004 include a $3.6 million after-tax gain on the sale of the income notes, and the results for 2003 include net income of $5.7 million from the settlement of lawsuits in the fourth quarter, which amounts are not expected to be recurring.

- The "other" segment's interest expense (and preferred securities distributions of trust subsidiaries in 2003) were $25.9 million in 2005, $27.6 million in 2004 and $33.3 million in 2003. In 2004, these financing costs decreased 17% compared to the prior year as HEI (1) completed the sale of 2 million shares (pre-split) of common stock in March 2004, the net proceeds of which were ultimately used, along with other corporate funds, to effect the redemption of $100 million aggregate principal amount of 8.36% Trust Originated Preferred Securities, and (2) completed the sale of $50 million of 4.23% medium-term notes. In 2005, financing costs continued to decrease 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 2003, HEI Power Corp. (HEIPC) wrote down its investment in Cagayan Electric Power & Light Co., Inc. (CEPALCO) from $7 million to $2 million and increased its reserve for future expenses by $1 million, resulting in a $4 million after-tax loss on disposal. In 2004, the HEIPC Group sold the company that holds its interest in 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 the "Notes to Consolidated Financial Statements."

Effects of inflation

U.S. inflation, as measured by the U.S. Consumer Price Index (CPI), averaged 3.4% in 2005, 2.7% in 2004, and 2.3% in 2003. Hawaii inflation, as measured by the Honolulu CPI, averaged 3.8% in 2005, 3.3% in 2004 and 2.3% in 2003. The increase in the Honolulu CPI for 2004 was due in large part to increases in gasoline and housing prices. The rate of inflation over the last two years has been trending upward and, although relatively low throughout this period, 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 PUC has generally approved rate increases to cover the effects of inflation. The PUC granted rate increases in 2005 for HECO, 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 the "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, 2005	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	$ 315	$ –	$ –	$ –	$ 315
Other checking	883	–	–	–	883
Savings	1,724	–	–	–	1,724
Money market	257	–	–	–	257
Term certificates	801	306	253	18	1,378
Total deposit liabilities	3,980	306	253	18	4,557
Securities sold under agreements to repurchase	373	264	50	–	687
Advances from Federal Home Loan Bank	206	467	263	–	936
Long-term debt, net	110	60	–	973	1,143
Operating leases, service bureau contract and maintenance agreements	27	43	33	37	140
Fuel oil purchase obligations (estimate based on January 1, 2006 fuel oil prices)	542	1,084	1,083	2,167	4,876
Power purchase obligations– minimum fixed capacity charges	118	240	236	1,279	1,873
Total (estimated)	$ 5,356	$ 2,464	$ 1,918	$ 4,474	$ 14,212

December 31, 2005 (in millions)	
Other commercial commitments to ASB customers	
Loan commitments (primarily expiring in 2006)	$ 76
Loans in process	140
Unused lines and letters of credit	892
	$ 1,108

The tables above do not include other categories of obligations and commitments, such as interest payable, trade payables, obligations under purchase orders, amounts that will become payable in future periods under collective bargaining and other employment agreements and employee benefit plans, and obligations that may arise under indemnities provided to purchasers of discontinued operations. As of December 31, 2005, the fair value of the assets held in trusts to satisfy the obligations of the 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 the "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 $10.0 billion as of December 31, 2005 and $9.7 billion as of December 31, 2004.

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	2005			2004		
(dollars in millions)						
Short-term borrowings	$	142	6%	$	77	3%
Long-term debt, net		1,143	45		1,167	47
Preferred stock of subsidiaries		34	1		34	1
Common stock equity		1,217	48		1,211	49
	$	2,536	100%	$	2,489	100%

As of March 6, 2006, 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 April 2005, S&P affirmed its corporate credit ratings of HEI, but revised its outlook from stable to negative, citing HECO's need for a rate increase to cover its growing expenses and yet to be recovered investments. See "Electric utility—Liquidity and capital resources" below.

As of December 31, 2005, $96 million of debt, equity and/or other securities were available for offering by HEI under an omnibus shelf registration and an additional $150 million principal amount of Series D notes were available for offering by HEI under its registered medium-term note program.

HEI periodically 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 and on behalf of HELCO and MECO. HEI had an average outstanding balance of commercial paper for 2005 of $3 million and had $6 million outstanding as of December 31, 2005. 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.

As of December 31, 2005, HEI maintained bank lines of credit with four different banks totaling $80 million (all maturing in 2006). These lines of credit are maintained by HEI principally to support the issuance of commercial paper, but also may be drawn for general corporate purposes. Accordingly, the lines of credit are available for short-term liquidity in the event a rating agency downgrade were to reduce or eliminate access to the commercial paper markets. Lines of credit to HEI totaling $30 million contain provisions for revised pricing in the event of a ratings change (e.g., a ratings downgrade of HEI medium-term notes from BBB/Baa2 to BBB-/Baa3 by S&P and Moody's, respectively, would result in a 12.5 to 50 basis points higher interest rate; a ratings upgrade from BBB/Baa2 to BBB+/Baa1 by S&P and Moody's, respectively, would result in a 12.5 to 20 basis points lower interest rate). There are no such provisions in HEI's other lines of credit. While each of the lines contain customary conditions that must be met in order to draw on them, none of HEI's line of credit agreements contain clauses that would affect access to the lines by reason of a ratings downgrade, nor do they have broad "material adverse change" clauses that could affect access to the lines in the event of any material adverse event so long as any such event is timely disclosed. As of December 31, 2005, the lines were undrawn. To manage future liquidity needs, including short-term liquidity for general corporate purposes and the refinancing of maturing long-term debt, the Company may seek to enter into new lines of credit, including multi-year credit, syndicated and/or bilateral facilities. The Company may also seek to increase the amount of credit available under such facilities as management deems appropriate. See S&P and Moody's ratings above and Note 6 of the "Notes to Consolidated Financial Statements."

Noteholders of $100 million of HEI 6.51% notes, due May 5, 2014, have a one-time option to redeem the notes on May 5, 2006 at 98.10% of the principal amount plus accrued interest.

Operating activities provided net cash of $218 million in 2005, $244 million in 2004 and $241 million in 2003. Investing activities used net cash of $202 million in 2005, $540 million in 2004 and $325 million in 2003. In 2005, 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 and sales of mortgage-related securities, net of purchases. Financing activities provided net cash of $22 million in 2005, $187 million in 2004 and $123 million in 2003. In 2005, net cash provided by financing activities was affected by several factors, including net increases in deposits and short-term borrowings and proceeds from the issuance of common stock, partly offset by net decreases in securities sold under agreements to repurchase, advances from the FHLB and long-term debt and by the payment of common stock dividends.

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 the "Notes to Consolidated Financial Statements."

Forecasted HEI consolidated "net cash used in investing activities" (excluding "investing" cash flows from ASB) for 2006 through 2008 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 $0.2 billion will be required during 2006 through 2008 to repay maturing HEI medium-term notes, which is expected to be repaid with the proceeds from the sale of medium-term notes, issuance of commercial paper, issuance of common stock under the stock option and incentive plan and dividends from subsidiaries. Additional debt and/or equity financing may be required to fund unanticipated expenditures not included in the 2006 through 2008 forecast, such as increases in the costs of or an acceleration of the construction of capital projects of the electric utilities, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements that might be required if there were significant declines in the market value of pension plan assets or changes in actuarial assumptions 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 the "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 2005, 2004 and 2003, 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. From time to time in the past, benefits have changed.

Contributions to the retirement benefit plans totaled $25 million in 2005 (comprised of $18 million made by the electric utilities, $6 million by ASB and $1 million by HEI Corporate), $37 million in 2004 and $48 million in 2003. Contributions to the retirement benefits plans are expected to total $14 million in 2006 ($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.

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 the "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 CHP and 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. The two phases of the EOTP are scheduled to be completed in 2007 and 2009. The PUC has approved HECO's plans for a new Energy Management System and a new Dispatch Center on Oahu, which are scheduled to be completed in 2006 and 2007, respectively, and are estimated to cost $25 million. 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, construction is proceeding on the installation of an 18 MW steam turbine at the Maalaea power plant site and the turbine is expected to be operational later in 2006. Further, the utilities are seeking PUC approval for additional DSM rebate programs and 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 (demand-side management (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) and HECO is continuing its existing DSM programs and cost recovery mechanisms pending the resolution of the EE DSM Docket. See "Most recent rate requests—HECO" and "Other regulatory matters—Demand-side management programs – agreements with the Consumer Advocate." In

December 2005, HELCO notified the PUC that it intends to file a request for an electric rate increase in spring 2006. See “Most recent rate requests—HELCO.”

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 an ongoing competitive bidding proceeding and has issued an order 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 $73 million in 2005 compared to $81 million in 2004 and $79 million in 2003. The decrease in 2005 was primarily due to 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 demand for electricity, and higher retirement benefits expense) and higher depreciation expense due to investments in capital projects, partly offset by the impact of HECO’s interim rate increase in late September 2005.

Results of Operations

(dollars in millions, except per barrel amounts)	2005	% change	2004	% change	2003
Revenues [1]	$ 1,806	16	$ 1,551	11	$ 1,397
Expenses					
Fuel oil	640	32	483	24	389
Purchased power	458	15	399	8	368
Other	546	11	495	7	463
Operating income	162	(7)	174	(2)	177
Allowance for funds used during construction	7	(15)	8	35	6
Net income	73	(10)	81	3	79
Return on average common equity	7.1%		8.3%		8.5%
Average price per barrel of fuel oil [1]	$ 56.61	33	$ 42.67	18	$ 36.23
Kilowatthour sales (millions)	10,090	–	10,063	3	9,775
Cooling degree days (Oahu)	4,971	(3)	5,107	2	5,010
Number of employees (at December 31)	2,066	3	2,013	8	1,862

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

• 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 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.

The trend of increased other operation and maintenance (O&M) expenses is expected to continue in 2006 as the electric utilities expect (1) higher demand side management expenses (that are generally passed on to customers through a surcharge and are being considered in the EE DSM Docket) and integrated resource planning expenses, (2) higher employee benefit expenses, primarily for retirement benefits and (3) higher production expense, primarily to meet higher demand levels and load growth achieved in 2004 and sustained in 2005. 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 during peak periods are lower than considered desirable in light of these circumstances. The electric utilities 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 growing demand, however, are increasing because of the decreasing reserve margin situation, and the rate of cost increases is not likely to lessen until a proposed new generating unit on Oahu is added in 2009. Increased O&M expense was one of the reasons HECO filed a request with the PUC in November 2004 to increase base rates. In late September 2005, HECO received interim rate relief (see "Most recent rate requests").

- In 2004, the electric utilities' revenues increased by 11%, or $154 million, from 2003 primarily due to higher energy prices ($114 million) and a 2.9% increase in KWH sales of electricity ($41 million). The increase in 2004 KWH sales from 2003 was primarily due to higher customer usage due in part to the strength in Hawaii's economy (including higher real personal income, lower unemployment, higher visitor days, increased military activity and stronger real estate market) and warmer weather (probably resulting in greater air conditioning usage). Cooling degree days were 1.9% higher in 2004 compared to 2003. The higher energy prices are also reflected in the higher amount of customer accounts receivable and accrued unbilled revenues.

Operating income was $3 million lower than in 2003 mainly due to higher other expenses, primarily higher maintenance expenses.

Fuel oil and purchased power expenses in 2004 increased by 24% and 8%, respectively, due primarily to higher fuel prices, which are generally passed on to customers, and more KWHs generated and purchased.

Other expenses increased 7% in 2004 due to a 1% (or $2 million) increase in "other operation" expense; a 20% (or $13 million) increase in maintenance expense; a 4% (or $4 million) increase in depreciation expense due to additions to plant in service in 2003; and a 10% (or $13 million) increase in taxes, other than income taxes, primarily due to the increase in revenues. "Other operation" expenses increased 1% in 2004 when compared to 2003 due primarily to higher administrative and general expenses, including increases in general liability reserves and workers' compensation claims, and higher transmission and distribution line inspection expense, largely offset by lower retirement benefits expense and emission fees. Pension and other postretirement benefit expenses for the electric utilities were $8 million lower than 2003 due primarily to the increase in plan assets as of December 31, 2003 compared to December 31, 2002 resulting from market performance and contributions of the electric utilities of $34 million during 2004. Maintenance expenses increased 20% due to greater scope of generating unit overhauls, higher production corrective maintenance, and higher transmission and distribution maintenance work.

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. As of March 6, 2006, 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 (decision & order (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). However, the ROACE used for purposes of the interim rate increase in HECO's current rate case was 10.7%. For 2005, the simple average ROACEs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 6.92%, 6.86% and 9.81%, respectively. HECO's actual ROACE is significantly lower than its allowed ROACE primarily because of increased O&M expenses, which are expected to continue and could result 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), which 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 until HELCO files a rate increase application (currently planned for spring 2006) and the PUC grants HELCO rate relief.

As of March 6, 2006, the 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 current HECO rate case is 8.66%. For 2005, the simple average RORs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 6.20%, 6.08% and 8.21%, respectively.

If, as discussed above, the utilities are required to record significant charges to AOCI related to a minimum liability for retirement benefits, the electric utilities' RORs would increase and could impact the rates the electric utilities are allowed to charge, which may ultimately result in reduced revenues and lower earnings. In December 2005, the electric utilities submitted a request to the PUC for approval to record as a regulatory asset and include in rate base the amount that would otherwise be charged to AOCI and reduce stockholder's equity (see Note 8 of the "Notes to Consolidated Financial Statements").

HECO. 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% return on rate base and an 11.5% return on average common equity. HECO requested approval of its proposed new energy efficiency (EE) DSM programs (Enhanced EE DSM programs), and associated utility incentive mechanism, in its rate case application. The requested increase included (1) transferring the cost of existing DSM programs from a surcharge line item on electric bills into base electricity charges, (2) the costs of Enhanced EE DSM programs, (3) the costs of capital improvement projects completed since the last rate case, (4) the proposed purchase of up to an additional 29 MW of firm capacity and energy from Kalaeloa Partners, L.P., (5) the cost of other measures taken to address peak load increases arising out of economic growth and increasing electricity use, and (6) increased O&M expenses. 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. The preliminary issues identified by the PUC for the new 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, and (4) for utility-incurred costs, what cost recovery mechanisms and cost levels are appropriate. The original parties/participants in this docket included HECO, the Consumer Advocate, the DOD, the County of Maui, two renewable energy organizations, an energy efficiency organization, and an environmental organization. In June 2005, however, the PUC, on its own initiative, included HELCO, MECO, Kauai Island Utility Cooperative and The Gas Company as parties to the docket, provided their participation is limited solely to the issues dealing with statewide energy policies. The procedural schedule for this docket calls for the parties to file final statements of position with the PUC in April 2006. Panel hearings are scheduled to take place in June 2006.

As a result of the bifurcation order, HECO is continuing its existing DSM programs and cost recovery mechanisms (under which program costs, shareholder incentives, and lost margins between rate cases are covered through a DSM surcharge). Relevant provisions of the stipulations under which the existing DSM programs have been extended continue to apply, including an agreement to cap the recovery of lost margins and shareholder incentives, if such recovery would cause HECO to exceed the ROR found to be reasonable by the PUC. The PUC used a ROR of 8.66% in its interim D&O discussed below. An estimated $32 million in revenue requirements for DSM program costs related to both the Enhanced EE DSM programs and to the extent recovered through the DSM surcharge, the existing DSM programs, were thus removed from HECO's rate increase request.

In September 2005, HECO, the Consumer Advocate and the DOD reached agreement among themselves on most of the issues in the rate case proceeding, subject to PUC approval. The remaining significant issue 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 the same month, 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 a 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 (described below); 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.

HELCO. In December 2005, HELCO notified the PUC that it intends to file a request for an electric rate increase in spring 2006. Preliminary estimates of the request are approximately 10%, however, it is expected that by using a proposed new tiered rate structure, most residential users would see smaller increases in the range of 3% to 7%. 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. 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). With energy efficiency and conservation, distributed generation and renewable energy options, management expects that CT-4 and CT-5 should be the last fossil fuel-burning units on the island of Hawaii for the foreseeable future. The next planned generating unit to provide firm power (available 24 hours) for the island will be the last phase of the combined cycle plant at Keahole, which will use waste heat from existing units and no additional fossil fuel.

Among the renewable energy projects on the island of Hawaii is the 10 MW Hawi Renewable Development wind farm and the planned expansion of the Apollo wind farm from 7 MW to approximately 20 MW (which may be delayed). Future projects for firm renewable purchased energy potentially include an expansion of a geothermal plant, a woodchip-burning plant, a County waste-to-energy plant and a pumped storage hydro plant. Other renewable sources include photovoltaics and, when commercially available, ethanol.

The earliest any increase, if allowed, may go into effect is expected to be in early 2007.

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 than would have been recorded under the previous rates and method.

Other regulatory matters

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO's energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs' forecasted levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over- or under-collection accruing interest at HECO, HELCO or MECO's authorized rate of return on rate base. HECO, HELCO and MECO filed a portion of the impact evaluation report for the 2000-2003 period with the PUC in November 2004 and adjusted the lost margin recovery in the second quarter of 2005. The study methodology for the remaining portion of the impact evaluation report (which evaluates the level of the DSM Programs' free-ridership and corresponding energy and demand impacts that would have occurred anyway in the absence of the DSM Programs), is under discussion with the Consumer Advocate. To date, adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO's financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs' actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs – agreements with the Consumer Advocate. 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 are to 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 will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. In October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs.

As previously discussed, as a result of the bifurcation order in HECO's rate case, HECO is continuing its existing DSM programs and cost recovery mechanisms, including the recovery of program costs, shareholder incentives and lost margins through a surcharge mechanism, pending the resolution of the EE DSM Docket. In the EE DSM Docket, HECO has requested PUC approval on an interim basis for certain modifications to its existing

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 its existing programs. On January 10, 2006, the Consumer Advocate filed comments on HECO's Interim DSM Proposals, which included an objection to the continued recovery of shareholder incentives and lost margins. HECO filed its response to the Consumer Advocate's comments on January 31, 2006, reaffirming its position that the continuation of shareholder incentives and lost margins is appropriate and in conformance with the PUC's order allowing the continuation of its existing DSM programs pending the resolution of the EE DSM Docket. The issue of the continuation of shareholder incentives and lost margins, or alternative incentive mechanisms, will be determined by the PUC as part of the EE DSM Docket. At this time the PUC has not issued a decision on HECO's Interim DSM Proposals.

In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved (1) the agreements regarding the temporary continuation of HECO's five existing DSM programs until HECO's next rate case and (2) 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 are 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 may request to extend the time of such accrual and recovery for up to one additional year. In the first half of 2006, HELCO and MECO plan to file a request to confirm that the bifurcation order in HECO's rate case had the effect of postponing the deadline for the recovery of HELCO and MECO's lost margins and shareholder incentives until resolution of the EE DSM Docket or, in the alternative, a request for extension of the recovery period for another year.

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 and 2005, 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 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.

<u>Avoided cost generic docket</u>. 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 Proceedings, 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. The parties have until May 31, 2006 to file.

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 integrated resource plans (IRPs). 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 have characterized their proposed IRPs as 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. See "Demand-side management programs–agreements with the Consumer Advocate" above, which includes a discussion of the electric utilities' residential and commercial and industrial load management programs.

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. Incremental IRP costs are deferred until approved for recovery, at which time they are amortized to expense. 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 of the costs.

The Consumer Advocate has objected to the recovery of $3.2 million (before interest) of the $11.8 million of incremental IRP costs incurred during the 1995-2004 period, and the PUC's decision is pending on this matter. As of December 31, 2005, the amount of revenues, including interest and revenue taxes, that the electric utilities recorded for IRP cost recoveries, subject to refund with interest, amounted to $18 million.

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.

In June 2005, HECO filed with the PUC an application for approval of funds to build a new nominal 100 MW simple cycle combustion turbine generating unit at Campbell Industrial Park and an additional 138 kilovolt transmission line to transmit power from the new unit and existing generating units at Campbell Industrial Park to the Oahu electric grid. Plans are for the combustion turbine to be run primarily as a "peaking" unit beginning in 2009, and to burn naphtha or diesel, but will have the ability to convert to using biofuels, such as ethanol, when they are commercially available. On December 15, 2005, HECO signed a contract with Siemens for the right to purchase up to two combustion turbine units. The contract allows the Company to terminate the contract at a specified payment amount if necessary combustion turbine (CT) project approvals are not obtained.

Preliminary costs for the new generating unit and transmission line, as well as related substation improvements, are estimated at $137 million. As of December 31, 2005 accumulated project costs for planning, engineering, permitting and AFUDC amounted to $2.7 million. HECO is now preparing an Environmental Impact Statement for the proposed project.

In a related application filed with the PUC in June 2005, HECO requested approval for an approximately $11.5 million package of community benefit measures 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 those 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 in Kahe power plant's operations.

In September 2005, the PUC suspended HECO's Campbell Industrial Park generating unit and transmission line additions application to allow more time to review the application. Also in September 2005, the PUC ordered HECO and the Consumer Advocate to submit a stipulated prehearing order for the community benefits application. In January 2006, the PUC granted an environmental group's motion to intervene and a neighboring business entity's motion to participate in the generating unit and transmission line application, and ordered HECO, the Consumer Advocate and the other parties (the environmental group and the business entity) to submit a stipulated prehearing order by March 13, 2006.

IRP-3 also includes plans to build a 180 MW coal unit in 2022. In addition, all existing generating units are currently planned to be operated (future environmental considerations permitting) beyond the 20-year IRP planning period (2006-2025).

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 planned to be added in 2011), and 10 MW from the acquisition of a wind resource in 2003 (currently, MECO expects to begin purchasing 30 MW of wind energy in 2006). Approximately 4 MW of additional generation through the year 2020 is planned 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, is currently expected to be installed in the third quarter of 2006.

MECO's third IRP is scheduled to be filed with the PUC in October 2006.

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 proposed in HELCO's second IRP included installing two 20 MW CTs at its Keahole power plant site (the installation of which were delayed, but were put into limited commercial operation in May and June 2004) and proceeding in parallel with a PPA with Hamakua Energy Partners, L.P. (HEP) for a 60 MW (net) dual-train combined-cycle (DTCC) facility (which was completed in December 2000). HELCO has deferred the retirements of some of its older generating 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 for the next firm capacity addition is the 2017 timeframe.

HELCO's third IRP is scheduled to be filed with the PUC by December 31, 2006.

Adequacy of supply.

HECO. As a result of load growth and other factors, HECO's 2005 Adequacy of Supply letter filed in March 2005 concluded that generation reserve margins, although substantial, were lower than is considered desirable on Oahu under the circumstances, and that there currently was an increased risk to generation reliability. Also, the letter stated that the risk of having generation-related customer outages would be higher if the peak reduction impacts of planned energy efficiency DSM programs, load management programs or CHP installations fall short of achieving their forecasted benefits. This situation is expected to continue, if the peak demand continues to grow as forecasted, at least until 2009, which is the earliest that HECO expects to be able to install its planned combustion turbine. The letter also indicated that HECO was working on plans to implement a number of potential interim mitigation measures, such as installing portable leased, distributed 1.6 MW generating units at substations or other sites (which were installed in the fourth quarter of 2005) and initiating a customer demand response program to supplement its load management programs (for which HECO plans to request approval in the first half of 2006). HECO did not experience actual generation shortfalls causing customer load shedding in 2005, in part because peak loads were lower than forecast in the second half of 2005.

HECO's 2006 Adequacy of Supply letter filed in March 2006 indicates that HECO's latest analysis estimates the reserve capacity shortfall to be between 170 MW and 200 MW in the 2006 to 2009 period, which is significantly larger than the 50 to 70 MW reserve capacity shortfall projected in the 2005 Adequacy of Supply letter. The increase in projected reserve capacity shortfall is largely due to the lower projected availability of existing generating units, and a reduction in the projected impacts from planned peak reduction measures. Generating units may 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. While the availability rates for generating units on Oahu remain better than those of comparable units on the U.S. mainland, the availability rates have declined in 2004 and 2005.

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 this situation to continue in the near-term and is forecasting lower availability rates than were used in the 2005 analyses.

To mitigate the projected reserve capacity shortfalls and to increase generating unit availability going forward, HECO is continuing to plan and implement mitigation measures, such as installing additional distributed generators at substations or other sites, seeking approval for 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. Given the magnitude of the projected reserve capacity shortfall, HECO also will evaluate the need to file an application with the PUC for approval to add more firm capacity (over and above the PUC application filed in June 2005 for a simple-cycle combustion turbine).

MECO. MECO's 2006 Adequacy of Supply letter filed in March 2006 indicated that MECO's Maui island system should have sufficient installed capacity to meet the forecasted loads. However, in December 2005, MECO's Maalaea unit 13, a 12.34 MW diesel generator suffered an equipment failure and the unit is not expected to be available for service until approximately June 2007. Until Maalaea unit 13 returns to service, the Maui island system at times may not have sufficient capacity in the event of an unexpected outage of the largest unit. MECO will implement appropriate mitigation measures to overcome insufficient reserve capacity situations.

HELCO. HELCO's 2006 Adequacy of Supply letter filed in February 2006 indicated that HELCO's generation capacity for the next three years, 2006 through 2008, is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

Collective bargaining agreements

Each of the electric utilities entered into a new 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 the "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. For example, although it is currently stalled in a House-Senate conference committee, comprehensive energy legislation is still before Congress that could increase the domestic supply of oil as well as increase support for energy conservation programs and mandate the use of renewables by utilities.

<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.

<u>Public Utility Holding Company Act of 1935 (1935 Act) and Public Utility Holding Company Act of 2005 (2005 Act).</u> 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 have filed a notification claiming a waiver of such requirements as single-state public utility holding companies. Regulation and oversight of HECO and its subsidiaries by the PUC, however, remains unchanged.

Renewable Portfolio Standard. The 2001 Hawaii Legislature adopted a law that required the utilities to meet a renewable portfolio standard (RPS) of 7% by December 31, 2003. HECO, HELCO and MECO are permitted to aggregate their renewable portfolios in order to achieve these standards. The electric utilities met this standard with over 8% of the utilities consolidated electricity sales for 2003 from renewable resources (as defined under the RPS law). The 2004 Hawaii Legislature amended the RPS law to require electric utilities to meet a renewable portfolio standard of 8% by December 31, 2005, 10% by December 31, 2010, 15% by December 31, 2015, and 20% by December 31, 2020. In 2005, the electric utilities attained over 11% of sales from renewable sources. The PUC has to determine if an electric utility is not able to meet the standard in a cost-effective manner or due to circumstances beyond its control. If such a determination is made, the utility is relieved of its responsibility to achieve the standard for that period of time. The PUC also may provide incentives to encourage electric utility companies to exceed their RPS or to meet their RPS ahead of time, or both.

The RPS law also directs the PUC, by December 31, 2006, to 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 November 1, 2004, the PUC transmitted an Initial Concept Paper, "Electric Utility Rate Design in Hawaii," describing the PUC's intended methodology for fulfilling the legislative mandate to formulate an electric utility rate design by December 31, 2006, that (1) enables the achievement of RPS, (2) encourages investments in renewable energy facilities, (3) conforms to the existing regulatory regime, which is cost-of-service regulation, or to alternative regulatory regimes, such as PBR, and (4) provides utilities an opportunity to earn a reasonable rate of return. The overall process envisioned by the PUC is the conduct of three sets of workshops (two sets of which have been completed), and the creation of a document that forms the basis of a set of rules to be adopted in a conventional rulemaking process to follow, providing input to the PUC's decisions on electric utility ratemaking. On July 26, 2005, the PUC transmitted a Second Concept Paper (SCP) authored by Economists Incorporated (EI), "Proposals for Implementing Renewable Portfolio Standards in Hawaii," which identified incentive regulation (IR) mechanisms, including renewable energy credit trading, alternative compliance fees, penalties and positive incentives. Subsequently, other IR mechanisms were proposed. Management cannot predict the outcome of this process.

The electric utilities continue to pursue a 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 for wind generation). They are also conducting integrated resource planning to evaluate the increased use of renewables within the electric utilities' service territories.

Among the various ways that the electric utilities support renewable energy are 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 filed and received a patent in February 2005 for an electronic shock absorber (ESA) that addresses power fluctuations from wind resources. An ESA demonstration system has been installed and is currently being tested at HELCO's Lalamilo wind farm. HECO has sought protection of intellectual property rights in its ESA technology, including a portfolio of U.S. and international patents and patent filings. HECO has an intellectual property license agreement with the party constructing the ESA demonstration system. 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. RHI has also signed a Framework Agreement for evaluation of three wind projects and two pumped storage hydroelectric projects on three islands. 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.

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 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. These amendments could have a negative effect on electric utility sales. However, based on experience under the 10 kw limit and assessment of market opportunity for 50 kw applications, management does not expect any such effect to be material.

Other legislation. A number of bills on energy were introduced in the 2006 Hawaii State legislative session. The majority of 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 energy resources. The electric utilities also are actively engaged in deliberations before the Legislature on matters that may affect them if adopted, such as bills that would direct the PUC to review and consider alternatives to the current energy cost adjustment clause, require the outsourcing of demand-side management programs, require the use of long-term fixed-price power purchase contracts for renewable energy generators, or modify the renewable portfolio standards law. At this time, it is not possible to predict the outcome of those deliberations.

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

To evaluate the technical feasibility of the “Broadband over Power Line” (BPL) technology and its applications, HECO completed a small-scale trial of the BPL technology. Based on the favorable results of the trial, HECO is proceeding with a pilot in an expanded residential/commercial area in Honolulu, which is expected to run through at least the second quarter of 2006. BPL-enabled utility applications being evaluated include distribution system line monitoring, advanced remote metering, residential direct load control and monitoring of distribution substation equipment. Although its evaluation will be focused primarily on utility applications of BPL, HECO is also evaluating broadband information services that might potentially be provided by other service providers.

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.

Liquidity and capital resources

HECO's consolidated capital structure was as follows:

December 31 (dollars in millions)		2005			2004	
Short-term borrowings	$	136	7%	$	89	4%
Long-term debt, net		766	38		753	40
Preferred stock		34	2		34	2
Common stock equity		1,039	53		1,017	54
	$	1,975	100%	$	1,893	100%

As of March 6, 2006, 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 April 2005, S&P affirmed its corporate credit ratings of HECO, but revised its outlook from stable to negative, citing HECO's need for a rate increase, rising operating expenses and yet to be recovered investments. 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)." In response to the PUC's interim rate decision for HECO, S&P stated "a final order that closely mirrors the interim ruling appears to be sufficient to lift key financial metrics to levels that are marginally suitable for Standard & Poor's guideposts for the 'BBB' rating category." However, S&P will reconsider its negative outlook when the PUC issues its final order. Moody's maintains a stable outlook on HECO. In May 2005, S&P revised HECO's business profile from "6" to "5". S&P ranks business profiles from "1" (strong) to "10" (weak).

HECO periodically 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. HECO had an average outstanding balance of commercial paper for 2005 of $95 million and had $136 million of commercial paper outstanding as of December 31, 2005. Management believes that if HECO's commercial paper ratings were to be downgraded, they might not be able to sell commercial paper under current market conditions.

As of December 31, 2005, HECO maintained bank lines of credit totaling $180 million with six different banks (all expiring in 2006). These lines of credit are principally maintained by HECO to support the issuance of commercial paper, but also may be drawn for general corporate purposes. Accordingly, the lines of credit are available for short-term liquidity in the event a rating agency downgrade were to reduce or eliminate access to the commercial paper markets. While each of the lines contain customary conditions that must be met in order to draw on them, none of HECO's line of credit agreements contain clauses that would affect access to the lines by reason of a ratings downgrade, nor do they have broad "material adverse change" clauses that could affect access to the lines in the event of any material adverse event so long as any such event is timely disclosed. As of December 31, 2005, the lines were unused. To manage HECO's future liquidity needs, HECO anticipates restructuring its lines of credit arrangements, including arranging a multi-year syndicated credit facility at a level consistent with the current level of lines of credit arrangements.

In 2005, the electric utilities' investing activities used $195 million in cash, primarily for capital expenditures, net of contributions in aid of construction. Financing activities provided net cash of $10 million, including a $48 million net increase in short-term borrowings and a $12 million net increase in long-term debt, partly offset by $52 million for the payment of common and preferred stock dividends. Operating activities provided cash of $185 million.

In May 2005, up to $160 million of Special Purpose Revenue Bonds (SPRBs) ($100 million for HECO, $40 million for HELCO and $20 million for MECO) were authorized by the Hawaii legislature for issuance, with PUC approval, through June 30, 2010 to finance the electric utilities' capital improvement projects.

In January 2005, the Department of Budget and Finance of the State of Hawaii issued, at par, Refunding Series 2005A SPRBs in the aggregate principal amount of $47 million (with a maturity of January 1, 2025 and a fixed coupon interest rate of 4.80%) and loaned the proceeds from the sale to HECO, HELCO and MECO. Proceeds from the sale, along with additional funds, were applied in February 2005 to redeem at a 1% premium a like principal amount of SPRBs bearing a higher interest coupon (HECO's, HELCO's, and MECO's aggregate $47 million of 6.60% Series 1995A SPRBs with an original stated maturity of January 1, 2025).

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 covering $100 million, $50 million and $15 million aggregate principal amount, respectively, for HECO, HELCO and MECO of their respective taxable unsecured notes due 2036. It is anticipated that the net proceeds from the sale of the notes will be used for capital expenditures and/or to repay short-term borrowings (including borrowings from affiliates) incurred for capital expenditures or to refinance short-term borrowings used for capital expenditures. The HELCO and MECO bonds will be fully and unconditionally guaranteed by HECO.

For the five-year period 2006 through 2010, approximately 51% of forecasted gross capital expenditures 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 U.S. Environmental Protection Agency (EPA) in 2004, the July 1999 Regional Haze Rule amendments or the proposed Clear Skies Bill, if adopted by Congress. The electric utilities' net capital expenditures (which exclude AFUDC and capital expenditures funded by third-party contributions in aid of construction) for 2006 through 2010 are currently estimated to total approximately $0.8 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 forecasted net capital expenditures and to reduce the level of short-term borrowings, which level is expected to fluctuate during this forecast period. Long-tem debt financing is expected to be required to fund this shortfall as well as any unanticipated expenditures not included in the 2006 through 2010 forecast, such as increases in the costs of, or an 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 and significant increases in contributions to the retirement benefit plans. 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 taxable unsecured notes, special purpose revenue bonds or trust preferred securities.

Proceeds from the anticipated sale of the taxable unsecured notes, cash flows from operating activities and temporary increases in short-term borrowings are expected to provide the forecasted $166 million needed for the net capital expenditures in 2006. For 2006, gross capital expenditures are estimated to be $207 million, including approximately $114 million for transmission and distribution projects, approximately $65 million for generation projects and approximately $28 million for general plant and other projects. Investment in renewable projects through RHI in 2006 is estimated to be $0.4 million. Consolidated net capital expenditures for HECO and subsidiaries for 2005, 2004 and 2003 were $194 million, $187 million and $131 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 2005, 2004 and 2003, they made voluntary contributions in those years. 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 2005, 2004 and 2003 totaled $18 million, $34 million and $31 million, respectively, and are expected to total $11 million in 2006. 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 2006 through 2010.

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 kilowatthour 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 demand-side management 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 2005 with assets of $6.8 billion and net income of $65 million, compared to assets of $6.8 billion as of December 31, 2004 and net income of $41 million in 2004. Excluding a $20 million after-tax charge for franchise taxes for prior years due to an adverse tax ruling, net income would have been $61 million in 2004 (see "Bank franchise taxes" below).

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

Due to improved asset quality resulting from the strength in the Hawaii economy and the real estate market, ASB recognized a $2 million after-tax reversal of allowance for loan losses during 2005 despite a $0.3 billion increase in its average balances of loans. ASB's allowance as a percentage of average loans was 0.90% at the end of 2005, compared to 1.08% and 1.44% at the end of 2004 and 2003, respectively. This ratio falls between the benchmark ratios for national banks and thrifts, which is appropriate 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 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 at year-end. 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) lengthening the maturities of costing liabilities in a lower interest-rate environment, which has stabilized the cost of other borrowings as interest rates have risen.

ASB has been undergoing a transformation, involving four major lines of business, to become a full service community bank serving both consumer and commercial customers. Two have been completed—commercial real estate and mortgage banking, and a third is nearing completion—commercial banking. The remaining transformation involving retail banking is intended to make ASB's retail area more customer-centric, rather than product-centric. The transformation project will require continued investment in people and technology. In addition to these transformation projects, ASB will continue to invest in projects and opportunities that will build core franchise value and add to earnings growth and returns. Additionally, the banking industry is constantly changing and ASB is continuously making the changes and investments necessary to adapt and remain competitive. ASB's ongoing challenge is to increase revenues faster than expenses.

Results of Operations

(dollars in millions)	2005	% change	2004	% change	2003
Revenues	$ 388	6	$ 364	(2)	$ 371
Net interest income	210	8	194	3	190
Operating income	105	–	105	13	93
Net income	65	58	41	(27)	56
Return on average common equity [1]	11.7%		8.0%		12.1%
Earning assets					
Average balance [2]	$ 6,374	3	$ 6,162	3	$ 5,980
Weighted-average yield	5.19%	4	4.98%	(5)	5.23%
Costing liabilities					
Average balance [2]	$ 6,157	4	$ 5,934	3	$ 5,739
Weighted-average rate	1.97%	4	1.90%	(12)	2.15%
Interest rate spread	3.22%	5	3.08%	–	3.08%
Net interest margin [3]	3.29%	4	3.15%	(1)	3.17%

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%.
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 the "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 and including additional bank franchise taxes in prior periods as if ASB had not taken a dividends received deduction on income from its REIT subsidiary. Management believes the adjusted information below presents ASB's net income on a more comparable basis for the periods shown. However, net income, including these adjustments, 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	2005	2004	2003
(dollars in thousands)			
Net income	$64,883	$41,062	$56,261
Cumulative bank franchise taxes, net of taxes, through December 31, 2003	–	20,340	–
Additional bank franchise taxes, net of taxes (if recorded in prior periods)	–	–	(3,793)
Net income – as adjusted	$64,883	$61,402	$52,468
ROACE – as adjusted [1]	11.7%	13.3%	11.7%

[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, the potential for 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, 2005, ASB's loan portfolio mix, net, consisted of 74% residential loans, 11% commercial loans, 8% commercial real estate loans and 7% consumer loans. As of December 31, 2004, ASB's loan portfolio mix, net, consisted of 77% residential loans, 9% commercial loans, 7% 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, 2005, ASB's costing liabilities consisted of 74% deposits and 26% FHLB advances and other borrowings. As of December 31, 2004, ASB's costing liabilities consisted of 71% deposits and 29% FHLB advances and other borrowings.

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, 2005 and 2004, the unrealized losses, net of tax benefits, on available-for-sale mortgage-related securities (including securities pledged for repurchase agreements) in AOCI was $37 million and $7 million, respectively, reflecting the impact of higher interest rates in 2005. 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	2005	2004	2003
(dollars in thousands)			
Loans receivable			
Average balances [1]	$ 3,411,389	$ 3,121,878	$ 3,071,877
Interest income [2]	205,084	184,773	198,948
Weighted-average yield	6.01%	5.92%	6.48%
Mortgage-related securities			
Average balances	$ 2,755,736	$ 2,799,303	$ 2,707,395
Interest income	121,847	116,471	107,496
Weighted-average yield	4.42%	4.16%	3.97%
Investments [3]			
Average balances	$ 207,258	$ 240,466	$ 200,891
Interest and dividend income	4,077	5,876	6,384
Weighted-average yield	1.97%	2.44%	3.18%
Total earning assets			
Average balances	$ 6,374,383	$ 6,161,647	$ 5,980,163
Interest and dividend income	331,008	307,120	312,828
Weighted-average yield	5.19%	4.98%	5.23%
Deposit liabilities			
Average balances	$ 4,453,762	$ 4,114,070	$ 3,888,145
Interest expense	52,064	47,184	53,808
Weighted-average rate	1.17%	1.15%	1.38%
Borrowings			
Average balances	$ 1,703,353	$ 1,819,598	$ 1,851,258
Interest expense	69,362	65,603	69,516
Weighted-average rate	4.07%	3.61%	3.76%
Total costing liabilities			
Average balances	$ 6,157,115	$ 5,933,668	$ 5,739,403
Interest expense	121,426	112,787	123,324
Weighted-average rate	1.97%	1.90%	2.15%
Net average balance	$ 217,268	$ 227,979	$ 240,760
Net interest income	209,582	194,333	189,504
Interest rate spread	3.22%	3.08%	3.08%
Net interest margin [4]	3.29%	3.15%	3.17%

1 Includes nonaccrual loans.

2 Includes interest accrued prior to suspension of interest accrual on nonaccrual loans, together with loan fees of $6.4 million, $6.1 million and $8.6 million for 2005, 2004 and 2003, respectively.

3 Includes stock in the FHLB of Seattle ($98 million as of December 31, 2005). In 2005, ASB received a stock dividend with a par value of $0.4 million, compared to $2.7 million in 2004 and $ 5.1 million in 2003. 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 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 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 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. This compares with a 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.

• Net interest income before the reversal of allowance for loan losses for 2004 increased by $5 million, or 2.5%, when compared to 2003. ASB experienced margin compression from a flattening yield curve as net interest margin decreased slightly from 3.17% in 2003 to 3.15% in 2004 due to faster growth in costing liabilities compared to earning assets. Growth in the loan portfolio and mortgage-related securities were funded by strong deposit growth. The increase in average loan portfolio balance was due to a strong Hawaii real estate market and low interest rates. The increase in the average investment and mortgage-related securities portfolios was due to the reinvestment into short-term investments of excess liquidity resulting from an inflow of deposits. On January 19, 2005, ASB became aware that the methodology it was using to amortize premiums and discounts on its mortgage-related securities portfolio was not in strict conformance with SFAS No. 91, "Accounting for Nonrefundable Fees and Costs Associated with Originating or Acquiring Loans and Initial Direct Costs of Leases." Specifically, ASB determined that its method for estimating the cumulative impact of revised effective yield following the provisions of paragraph 19 of SFAS No. 91 when considering prepayments no longer approximated the results from a strict application of these provisions. This resulted in over-amortization of net premiums. Accordingly, ASB recalculated the amortization of premiums and discounts on its December 31, 2004 mortgage-related securities portfolio in strict accordance with SFAS No. 91 and recognized $1.5 million in additional net income ($2.5 million pre-tax interest income) in the fourth quarter of 2004 for an adjustment for net premium overamortization. Average deposit balances grew by $226 million in 2004 compared to 2003. The higher deposit balances enabled ASB to repay some of its higher costing other borrowings.

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 $8 million ($5 million, net of tax) in 2004. This compares with a provision for loan losses of $3 million ($2 million, net of tax) in 2003.

Noninterest income for 2004 decreased by $1 million, or 2.3%, when compared to 2003 due to $4 million of gains on sale of securities in 2003, partially offset by higher fee income in 2004.

Noninterest expense for 2004 increased by $3 million, or 1.8%, over 2003, primarily due to SOX compliance costs.

• During 2005, 2004 and 2003, ASB's allowance for loan losses decreased by $3 million, $10 million and $1 million, respectively.

ASB's nonaccrual and renegotiated loans represented 0.2%, 0.4% and 0.4% of total loans outstanding as of December 31, 2005, 2004 and 2003, respectively. See Note 4 of the "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 and the last three quarters of 2005. Subject to the impact of legislation being considered by Congress (discussed below under "Legislation and regulation"), member access to the FHLB of Seattle funding and liquidity is expected to continue unimpeded during implementation of the three-year plan.

Legislation and regulation

Congress is considering legislation to revamp oversight of government-sponsored enterprises (GSEs). This legislation would abolish the Office of Federal Housing Enterprise Oversight (regulator of Fannie Mae and Freddie Mac) and the Federal Housing Finance Board (regulator of the FHLB), create a new regulatory agency to oversee GSEs, and invest in this new agency the authority, among other things, to place limitations on "non-mission" assets, to establish prudent management and operation standards for GSEs concerning matters such as the management of asset and investment portfolio growth, to impose "prompt-corrective action" measures on a GSE in the event of under-capitalization, and to exercise oversight enforcement powers. By possibly restricting GSE asset growth, if enacted, this legislation could potentially limit the availability of advances from the FHLB of Seattle to ASB and sale of loans to Fannie Mae. ASB believes, however, that if this legislation is adopted and implemented in these ways, its results will not be materially adversely affected because ASB has access to other funding sources and secondary markets to sell its loans.

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 (dollars in millions)	2005	% change	2004	% change
Assets	$6,835	1	$ 6,767	4
Available-for-sale investment and mortgage-related securities	2,629	(11)	2,953	9
Investment in stock of Federal Home Loan Bank of Seattle	98	–	97	3
Loans receivable, net	3,567	10	3,249	4
Deposit liabilities	4,557	6	4,296	7
Securities sold under agreements to repurchase	687	(15)	811	(2)
Advances from FHLB	936	(5)	988	(3)

As of December 31, 2005, 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 increased by $261 million during 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, 2005, FHLB borrowings totaled approximately $0.9 billion, representing 14% 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, 2005, ASB's unused FHLB borrowing capacity was approximately $1.5 billion. As of December 31, 2005, securities sold under agreements to repurchase totaled $0.7 billion, representing 10% 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, 2005, 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, 2005, ASB had $2.4 million of loans on nonaccrual status, or 0.1% of net loans outstanding, compared to $6.4 million, or 0.2%, as of December 31, 2004. As of December 31, 2005 and 2004, ASB's real estate acquired in settlement of loans was $0.2 million and $0.9 million, respectively.

In 2005, net cash of $40 million was used in investing activities primarily due to net increases in loans held for investment, partly offset by repayments and sales of mortgage-related securities, net of purchases. Financing activities provided net cash of $44 million due to net increases in deposits, partly offset by net decreases in advances from the FHLB and securities sold under agreements to repurchase and the payment of common stock dividends. Operating activities provided cash of $42 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, 2005, ASB was well-capitalized (see "Regulation of ASB" for ASB's capital ratios).

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 registrant'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 registrant in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the registrant, or engages in leasing, hedging or research and development services with the registrant.

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" in the Company's Annual Report on Form 10-K.

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 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 the competitive bidding proceeding is to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii.

The current parties/participants in the competitive bidding proceeding include the Consumer Advocate, HECO, HELCO, MECO, Kauai Island Utility Cooperative and a renewable energy organization. The issues to be addressed in the proceeding include the benefits and impacts of competitive bidding, whether a competitive bidding system should be developed for acquiring or building new generation, and revisions that should be made to integrated resource planning. If it is determined that a competitive bidding system should be developed, issues include 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. The PUC stated it would consider related matters on a case-by-case basis pending completion of the competitive bidding and DG proceedings. Statements of position by, information requests to, and responses by the parties/participants were filed in March through August 2005. The PUC held panel hearings in December 2005. The parties will engage in working sessions to discuss a competitive bidding framework and file a joint submission by March 31, 2006 identifying areas of agreement and disagreement for the PUC's review and consideration. After the filing of briefs, oral arguments are expected to be presented to the PUC in May 2006. Management cannot predict the ultimate outcome of this proceeding or its effect on the ability of the electric utilities to acquire or build additional generating capacity in the future.

Distributed generation proceeding. The electric utilities have been expanding their use and consideration of DG resources to meet the energy needs of the utility systems. Utility-sited DG has been deployed to provide peaking capacity and to defer the need for transmission system infrastructure. The utilities have also been pursuing the possibility of offering utility-owned, customer-sited combined heat and power (CHP) systems to large customers to produce electricity and thermal energy, which is generally used in Hawaii to heat water and, through an absorption chiller, drive an air conditioning system. The electric energy generated by these systems is usually lower in output than the customer's load, which results in the customer's continued connection to the utility grid to make up the difference in electricity demand and to provide back up electricity. Incremental generation from such customer-sited CHP systems and other forms of DG is intended to complement traditional central station power, as part of the electric utilities' plans to meet their forecasted load growth.

In October 2003, the PUC opened the DG proceeding to determine the potential benefits and impact of DG on Hawaii's electric distribution systems and markets and to develop policies and a framework for DG projects deployed in Hawaii.

In April 2004, the PUC issued an order in the DG proceeding defining issues related to planning (e.g., who should own and operate projects and the roles of the electric utilities and PUC), impacts (e.g., on the transmission and distribution systems, power quality and reliability, the use of fossil fuels and utility costs) and implementation (e.g., issues concerning matters to be considered to allow a DG facility's interconnection with the utility's grid, appropriate rate design and cost allocation issues, and revisions that should be made to PUC and utility rules and practices). Hearings were held in December 2004.

Prior to opening of the investigative DG proceeding, 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.

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 HECO 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 least 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.

The D&O also requires the electric utilities to 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.

On March 1, 2006, the electric utilities filed a Motion for Clarification and/or Partial Reconsideration 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.

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 has been expanding its traditional consumer focus to be a full-service community bank 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.

In recent years, there has been significant bank and thrift merger activity affecting Hawaii, including the merger in 2004 of the holding companies for the state's 4th and 5th largest financial institutions (based on assets). Management cannot predict the impact, if any, of these mergers on the Company's future competitive position, results of operations or financial condition.

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 $17.8 million in 2006 as compared to $11.3 million in 2005, partly as a result of the impact of lower interest rates on the discount rate used to determine retirement benefit liabilities.
- 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, 2005, the fair value and carrying value of the investment and mortgage-related securities held by ASB were $2.6 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. Federal government monetary policies and low interest rates have resulted in high mortgage refinancing volume in 2003 and 2004 as well as accelerated prepayments of loans and securities. The Federal Reserve began increasing rates in 2004, while longer-term interest rates have not increased significantly, causing a flattening of the yield curve. This type of interest rate environment typically puts downward pressure on ASB's net interest margin. As of December 31, 2005, the Company had no floating-rate long-term debt outstanding. As of December 31, 2005, consolidated HEI had $142 million of commercial paper outstanding with a weighted-average interest rate of 4.47% and maturities ranging from 13 to 21 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 the "Notes to Consolidated Financial Statements." ASB also has no insurance coverage for business interruption nor 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 losses in amounts that would have a material adverse effect on its 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.

For discussions of the ongoing Honolulu Harbor environmental investigation, the July 1999 Regional Haze Rule amendments and section 316(b) of the federal Clean Water Act, see "Environmental regulation" in Note 3 of the "Notes to Consolidated Financial Statements." There can be no assurance that a significant environmental liability will not be incurred by the electric utilities.

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, 2005, HECO and its subsidiaries had recognized $32 million of revenues with respect to interim orders regarding certain integrated resource planning costs and an Oahu 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 $3.2 million (before interest) of the $11.8 million of incremental IRP costs incurred by the utilities during the 1995-2004 period, and the PUC's decision is pending on this matter. In addition, HECO and MECO incurred approximately $1.0 million of incremental integrated resource planning costs for 2005, 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&O in the current HECO rate case or when D&Os 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 capital expenditures, or other factors could result in the electric utilities seeking rate relief more often than in the past.

The rate schedules of each of the electric utilities include energy cost adjustment clauses 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. In 2004 PUC decisions approving the electric utilities' fuel supply contracts, the PUC affirmed the electric utilities' right to include in their respective energy cost adjustment clauses 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 energy cost adjustment clauses in rate cases. While there was no opposition to the continuation of the clause by the parties in the pending HECO rate case, there can be no assurance concerning actions the PUC may take in its final order in the pending HECO rate case or otherwise in the future with respect to these clauses. In addition, the State Legislature is currently considering legislation which would direct the PUC to review and consider alternatives to the current energy cost adjustment clause and, at this time, it is not possible to predict the outcome of those deliberations. Until such time, the electric utilities will continue to recover their fuel contract costs through their respective energy cost adjustment clauses to the extent the costs are not recovered in their base rates.

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 the "Notes to Consolidated Financial Statements." The Company estimates that 79.5% of the net energy generated and purchased by HECO and its subsidiaries in 2006 will be generated from the burning of oil. Purchased KWHs provided approximately 39.1% of the total net energy generated and purchased in 2005 compared to 38.2% in 2004 and 39.2% in 2003.

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 power purchase agreement, 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' power purchase agreements require that the IPPs maintain minimum fuel inventory levels and all of the firm capacity power purchase agreements 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 9%, 7% and 11% for 2005, 2004 and 2003, respectively, when compared to the prior year. This trend of increased operation and maintenance expenses is expected to continue in 2006 as the electric utilities anticipate: (1) higher demand-side management 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. 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 filed a request with the PUC in November 2004 to increase base rates. In September 2005, HECO received interim rate relief (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 the "Notes to Consolidated Financial Statements."

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, 2005, 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, 2005 with a tangible capital ratio of 7.4% (1.5%), a core capital ratio of 7.4% (4.0%) and a total risk-based capital ratio of 15.1% (8.0%).
- ASB met the capital requirements to be generally considered "well-capitalized" (noted in parentheses) as of December 31, 2005 with a leverage ratio of 7.4% (5.0%), a Tier-1 risk-based capital ratio of 14.2% (6.0%) and a total risk-based capital ratio of 15.1% (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 its shareholders 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 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 and offering "pass-through" insurance coverage (i.e., insurance coverage that passes through to each owner/beneficiary of the applicable deposit) for the deposits of most employee benefit plans (i.e., $100,000 per individual participant, not $100,000 per plan). As of December 31, 2005, 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, and a failure or inability to comply with those restrictions could effectively result in the required divestiture of ASB. As of December 31, 2005, approximately 87% 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 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 the "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. Management has reviewed the material estimates and critical accounting policies with the HEI Audit Committee.

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

Investment 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 one investment security (a federal agency obligation), 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, 2005, ASB had mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $2.2 billion and private-issue mortgage-related securities valued at $0.4 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, as a significant amount of capital assets and lease obligations would need 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 the "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" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." 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 the "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.

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 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. See "Environmental regulation" in Note 3 of the "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 periodically 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 Note 10 of the "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 they are probable of future recovery in customer rates. As of December 31, 2005, regulatory liabilities and regulatory assets amounted to $219 million and $111 million, respectively. Regulatory liabilities and regulatory assets are itemized in Note 3 of the "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 the regulatory assets as of December 31, 2005 are probable of recovery. 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, 2005, revenues applicable to energy consumed, but not yet billed to customers, amounted to $91 million.

Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order. Also, the rate schedules of the electric utilities include energy cost adjustment clauses 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 power purchase agreements or execute amendments of existing power purchase agreements. 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 the "Notes to Consolidated Financial Statements."

Bank

Allowance for loan losses. See Note 1 of the "Notes to Consolidated Financial Statements." As of December 31, 2005, ASB's allowance for loan losses was $30.6 million and ASB had $2.4 million of loans on nonaccrual status. In 2005, ASB's reversal of allowance for loan losses was $3.1 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, 2005.

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 energy cost adjustment clauses in their rate schedules. See discussion of the energy cost adjustment clauses 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. However, until the Company sell its shares of Hoku (a Hawaii fuel cell company that completed its initial public offering in August 2005), fluctuations in the market price of the shares will impact the Company's net income. The Company's current exposure to foreign currency exchange rate risk is not material.

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 the "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 immediate and sustained parallel shocks of the yield curve in increments of +/- 100 basis points. At the end of 2005, the timing of the interest rate changes in the alternate scenarios for NII sensitivity analysis was modified from instantaneous interest rate changes to "rate ramps" or gradual interest changes. While the magnitude of the interest rate changes in the alternate scenarios remains the same, the timing of the changes is gradual, and accomplished by moving the yield curve in a parallel fashion, over the next twelve month period. This change was made because gradual rate changes more closely reflect historical patterns of interest rate movements, and are therefore more useful in measuring and managing NII sensitivity. As of December 31, 2005, NII sensitivity results are shown under both instantaneous rate shocks and rate ramps. 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, future pricing spreads for assets and liabilities 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, 2005 and 2004 constitute "forward-looking statements" and were as follows:

December 31	2005				2004		
	Change in NII	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			Instantaneous change		
+300	(2.7)%	(8.1)%	8.12%	(332)	(7.7)%	7.28%	(367)
+200	(1.8)	(5.5)	9.34	(210)	(5.0)	8.69	(226)
+100	(0.9)	(2.8)	10.49	(95)	(2.0)	9.99	(96)
Base	–	–	11.44	–	–	10.95	–
-100	1.5	2.2	11.91	47	(3.9)	11.22	27
-200	1.0	(5.0)	11.62	17	**	**	**

* Change from base case in basis points.

** Not performed due to the low level of interest rates as of December 31, 2004.

Management believes that ASB's interest rate risk position as of December 31, 2005 represents a reasonable level of risk. Under the instantaneous rate shock scenarios, the December 31, 2005 NII profile is slightly more sensitive to changes in interest rates compared to the NII profile on December 31, 2004.

In the –200 basis point scenario, NII falls relative to the base case because expectations of faster prepayments and lower reinvestment rates causes the yield on assets to decline faster than the cost of liabilities, which do not fall as much because the current low level of rates on existing liabilities limits the amount by which they can decline.

ASB's base NPV ratio as of December 31, 2005 was higher than on December 31, 2004, primarily as a result of changes in the composition of the balance sheet and changes in the level and shape of the yield curve. During 2005, ASB's funding mix shifted, as higher costing wholesale borrowings were replaced with lower cost deposits. This contributed to the increase in ASB's NPV ratio.

ASB's NPV ratio sensitivity measures as of December 31, 2005 were comparable to the measures as of December 31, 2004.

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, 2005, 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 the "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, 2005 of $142 million and a hypothetical 10% increase/decrease in interest rates, annual interest expense would have increased/decreased on that commercial paper by $0.6 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, 2005 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, 2005.

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, 2005. This report appears on page 49.

Robert F. Clarke
Chairman, President and
Chief Executive Officer

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

Curtis Y. Harada
Controller and
Chief Accounting Officer

March 6, 2006

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, 2005, 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, 2005, 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, 2005, 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, 2005 and 2004, 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, 2005, and our report dated March 6, 2006 expressed an unqualified opinion on those consolidated financial statements and referred to the adoption of Financial Accounting Standards Board Interpretation No. 46(R), Consolidation of Variable Interest Entities.

KPMG LLP

Honolulu, Hawaii
March 6, 2006

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, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 1 and 5 to consolidated financial statements, effective January 1, 2004, the Company adopted Financial Accounting Standards Board Interpretation No. 46(R), *Consolidation of Variable Interest Entities*.

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, 2005, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 6, 2006 expressed an unqualified opinion on management's assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Honolulu, Hawaii
March 6, 2006

Consolidated Financial Statements

Consolidated Statements of Income

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2005	2004	2003
(in thousands, except per share amounts)			
Revenues			
Electric utility	$ 1,806,384	$ 1,550,671	$ 1,396,685
Bank	387,910	364,284	371,320
Other	21,270	9,102	13,311
	2,215,564	1,924,057	1,781,316
Expenses			
Electric utility	1,644,681	1,376,768	1,220,120
Bank	283,009	259,310	278,565
Other	16,452	17,019	19,064
	1,944,142	1,653,097	1,517,749
Operating income (loss)			
Electric utility	161,703	173,903	176,565
Bank	104,901	104,974	92,755
Other	4,818	(7,917)	(5,753)
	271,422	270,960	263,567
Interest expense – other than bank	(75,309)	(77,176)	(69,292)
Allowance for borrowed funds used during construction	2,020	2,542	1,914
Preferred stock dividends of subsidiaries	(1,894)	(1,901)	(2,006)
Preferred securities distributions of trust subsidiaries	–	–	(16,035)
Allowance for equity funds used during construction	5,105	5,794	4,267
Income from continuing operations before income taxes	201,344	200,219	182,415
Income taxes	73,900	92,480	64,367
Income from continuing operations	127,444	107,739	118,048
Discontinued operations – gain (loss) on disposal, net of income taxes	(755)	1,913	(3,870)
Net income	$ 126,689	$ 109,652	$ 114,178
Basic earnings (loss) per common share			
Continuing operations	$ 1.58	$ 1.36	$ 1.58
Discontinued operations	(0.01)	0.02	(0.05)
	$ 1.57	$ 1.38	$ 1.53
Diluted earnings (loss) per common share			
Continuing operations	$ 1.57	$ 1.36	$ 1.57
Discontinued operations	(0.01)	0.02	(0.05)
	$ 1.56	$ 1.38	$ 1.52
Dividends per common share	$ 1.24	$ 1.24	$ 1.24
Weighted-average number of common shares outstanding	80,828	79,562	74,696
Dilutive effect of stock-based compensation	372	157	278
Adjusted weighted-average shares	81,200	79,719	74,974

See accompanying "Notes to Consolidated Financial Statements."

Consolidated Balance Sheets

Hawaiian Electric Industries, Inc. and Subsidiaries

December 31		2005		2004
(dollars in thousands)				
ASSETS				
Cash and equivalents		$ 151,513		$ 132,138
Federal funds sold		57,434		41,491
Accounts receivable and unbilled revenues, net		249,473		208,533
Available-for-sale investment and mortgage-related securities		2,629,351		2,953,372
Investment in stock of Federal Home Loan Bank of Seattle (estimated fair value $97,764 and $97,365)		97,764		97,365
Loans receivable, net		3,566,834		3,249,191
Property, plant and equipment, net				
Land	$ 46,350		$ 46,311	
Plant and equipment	3,884,886		3,698,539	
Construction in progress	150,376		112,293	
	4,081,612		3,857,143	
Less – accumulated depreciation	(1,538,836)	2,542,776	(1,434,840)	2,422,303
Regulatory assets		110,718		108,630
Other		456,134		414,971
Goodwill and other intangibles		89,580		91,263
		$ 9,951,577		$ 9,719,257
LIABILITIES AND STOCKHOLDERS' EQUITY				
Liabilities				
Accounts payable		$ 183,336		$ 147,054
Deposit liabilities		4,557,419		4,296,172
Short-term borrowings		141,758		76,611
Securities sold under agreements to repurchase		686,794		811,438
Advances from Federal Home Loan Bank		935,500		988,231
Long-term debt, net		1,142,993		1,166,735
Deferred income taxes		207,997		229,765
Regulatory liabilities		219,204		197,089
Contributions in aid of construction		256,263		235,505
Other		369,390		325,307
		8,700,654		8,473,907
Minority interests				
Preferred stock of subsidiaries – not subject to mandatory redemption		34,293		34,405
Stockholders' equity				
Preferred stock, no par value, authorized 10,000,000 shares; issued: none		–		–
Common stock, no par value, authorized 100,000,000 shares; issued and outstanding: 80,983,326 shares and 80,687,350 shares		1,018,966		1,010,090
Retained earnings		235,394		208,998
Accumulated other comprehensive loss, net of income tax benefits				
Net unrealized losses on securities	$(36,476)		$(7,036)	
Minimum pension liability	(1,254)	(37,730)	(1,107)	(8,143)
		1,216,630		1,210,945
		$ 9,951,577		$ 9,719,257

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, 2002	73,618	$ 839,503	$176,118	$ 30,679	$1,046,300
Comprehensive income:					
Net income	–	–	114,178	–	114,178
Net unrealized losses on securities:					
Net unrealized losses arising during the period, net of tax benefits of $11,538	–	–	–	(29,530)	(29,530)
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $1,082	–	–	–	(2,110)	(2,110)
Minimum pension liability adjustment, net of taxes of $2,027	–	–	–	3,787	3,787
Comprehensive income (loss)	–	–	114,178	(27,853)	86,325
Issuance of common stock:					
Dividend reinvestment and stock purchase plan	1,658	36,052	–	–	36,052
Retirement savings and other plans	562	11,433	–	–	11,433
Expenses and other, net	–	1,443	–	–	1,443
Common stock dividends ($1.24 per share)	–	–	(92,522)	–	(92,522)
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

As of December 31, 2005, Hawaiian Electric Industries, Inc. (HEI) had reserved a total of 14,915,552 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	2005	2004	2003
(in thousands)			
Cash flows from operating activities			
Net income	$ 126,689	$ 109,652	$ 114,178
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation of property, plant and equipment	133,892	125,560	120,633
Other amortization	8,269	15,965	29,766
Provision (reversal of allowance) for loan losses	(3,100)	(8,400)	3,075
Gain on sale of income notes	–	(5,607)	–
Deferred income taxes	43	12,349	2,838
Allowance for equity funds used during construction	(5,105)	(5,794)	(4,267)
Changes in assets and liabilities, net of effects from the disposal of businesses			
Increase in accounts receivable and unbilled revenues, net	(40,940)	(20,823)	(11,389)
Increase in fuel oil stock	(26,880)	(14,958)	(7,963)
Increase in federal tax deposit	(30,000)	–	–
Increase in prepaid pension benefit cost	(2,661)	(24,539)	(24,681)
Increase in accounts payable	36,282	17,913	1,750
Increase in taxes accrued	37,631	46,675	22,045
Changes in other assets and liabilities	(15,682)	(3,841)	(4,653)
Net cash provided by operating activities	218,438	244,152	241,332
Cash flows from investing activities			
Available-for-sale investment and mortgage-related securities purchased	(486,432)	(1,105,133)	(2,155,980)
Principal repayments on available-for-sale investment and mortgage-related securities	727,901	803,517	1,860,383
Proceeds from sale of available-for-sale mortgage-related securities	28,039	45,207	243,406
Net increase in loans held for investment	(304,212)	(113,991)	(130,205)
Net proceeds from sale of investments	33,809	9,981	–
Proceeds from sale of real estate acquired in settlement of loans	624	1,617	7,728
Capital expenditures	(223,675)	(214,654)	(162,891)
Contributions in aid of construction	21,083	8,522	12,963
Distributions from unconsolidated subsidiaries	–	24,379	–
Other	909	180	(624)
Net cash used in investing activities	(201,954)	(540,375)	(325,220)
Cash flows from financing activities			
Net increase in deposit liabilities	261,247	269,922	225,478
Net increase in short-term borrowings with original maturities of three months or less	65,147	76,611	–
Net increase in retail repurchase agreements	18,519	25,050	13,085
Proceeds from securities sold under agreements to repurchase	873,256	753,608	1,965,575
Repayments of securities sold under agreements to repurchase	(1,017,645)	(799,250)	(1,809,945)
Proceeds from advances from Federal Home Loan Bank	195,000	129,200	373,500
Principal payments on advances from Federal Home Loan Bank	(247,731)	(158,022)	(532,699)
Proceeds from issuance of long-term debt	59,462	103,097	167,935
Repayment of long-term debt	(84,000)	(224,166)	(210,000)
Preferred securities distributions of trust subsidiaries	–	–	(16,035)
Net proceeds from issuance of common stock	3,689	110,017	29,824
Common stock dividends	(100,238)	(93,864)	(75,119)
Other	(5,015)	(4,768)	(8,887)
Net cash provided by financing activities	21,691	187,435	122,712
Cash flows from discontinued operations (revised – see Note 11)			
Cash flows used in operating activities	(2,857)	(3,571)	(3,361)
Cash flows provided by investing activities	–	6,000	–
Net cash provided by (used in) discontinued operations	(2,857)	2,429	(3,361)
Net increase (decrease) in cash and equivalents and federal funds sold	35,318	(106,359)	35,463
Cash and equivalents and federal funds sold, January 1	173,629	279,988	244,525
Cash and equivalents and federal funds sold, December 31	$ 208,947	$ 173,629	$ 279,988

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.

<u>Consolidation of VIEs</u>. In December 2003, the FASB issued Interpretation No. (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.

As of December 31, 2005, Hawaiian Electric Company, Inc. (HECO) and its subsidiaries had six purchase power agreements (PPAs) for a total of 540 MW of firm capacity, and other PPAs with smaller independent power producers (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 2005 totaled $458 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPower totaling $137 million, $169 million, $63 million and $33 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 and its subsidiaries have reviewed their 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 by telephone to explain and repeat its request for information. (HECO and its subsidiaries excluded their Schedule Q providers from the scope of FIN 46R because HECO and its subsidiaries' variable interest in the provider would not be significant to HECO and its subsidiaries and they did not participate significantly in the design of the provider.) Some of the IPPs provided sufficient information for HECO and its subsidiaries 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 and its subsidiaries to determine the applicability of FIN 46R, and HECO and its subsidiaries were unable to apply FIN 46R to these IPPs. In January 2005, 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. Kalaeloa has since provided its information (see below).

As required under FIN 46R, HECO and its subsidiaries have continued their efforts to obtain from the IPPs the information necessary to make the determinations required under FIN 46R. If the requested information is ultimately received, a possible outcome of future analysis is the consolidation of an IPP 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.

In October 2004, Kalaeloa and HECO executed two amendments to their PPA, under which Kalaeloa would make available additional firm capacity to HECO. The amendments became effective when the costs of the additional capacity and purchased power were included in HECO's rates as a result of an Interim D&O issued in HECO's current rate case. The additional firm capacity to be provided by Kalaeloa is 28 MW. Kalaeloa provided HECO the information HECO needed to complete its determination of whether Kalaeloa is a variable interest entity, and, whether HECO is the primary beneficiary. While it has been determined that Kalaeloa is a variable interest entity, HECO has concluded that it is not the primary beneficiary of that entity and accordingly Kalaeloa need not be consolidated in HECO's consolidated financial statements. See Note 5 for additional information regarding the application of FIN 46R to Kalaeloa.

In October 2004, Hawaii Electric Light Company, Inc. (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 windfarm allowed capacity of 20 MW. Due to problems with its wind turbine supplier, however, Apollo is claiming an event of force majeure under the PPA and the project may be delayed. In December 2004, MECO executed a new PPA with Kaheawa Wind Power, LLC (KWP), which is installing a 30 MW windfarm on Maui. The revised PPA with Apollo and new PPA with KWP were approved by the Public Utilities Commission of the State of Hawaii (PUC) in March 2005, and became effective in April 2005. The PPAs require Apollo and KWP to provide information necessary to (1) determine if HELCO and Maui Electric Company, Limited (MECO) must consolidate Apollo and KWP, respectively, under FIN 46R, (2) consolidate Apollo and/or KWP, if necessary under FIN 46R, and (3) comply with Section 404 of Sarbanes-Oxley Act of 2002 (SOX). Management is in the process of obtaining the information necessary to complete its determination of whether Apollo or KWP are VIEs and, if so, whether HELCO or MECO, respectively, is the primary beneficiary. Based on information currently available, management believes the impact on consolidated HECO's financial statements of the consolidation of Apollo and/or KWP, if necessary, would not be material. However, depending on the magnitude of the improvements contemplated in the PPAs, the impact of a required consolidation of Apollo and KWP could be material in the future. If required to consolidate the financial statements of Apollo and/or KWP in the future and such consolidation had a material effect, HECO would retrospectively apply FIN 46R in accordance with SFAS No. 154, "Accounting Changes and Error Corrections."

See Note 5 for additional information regarding the application of FIN 46R.

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 on investment and mortgage-related securities are accreted or premiums 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) 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.

In the future, 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 2005, 2004 and 2003.

Retirement benefits. Pension and other postretirement benefit costs/(returns) are charged/(credited) primarily to expense and electric utility plant. The 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 statutory funding 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 statutory funding limits, cash flow requirements and reviews of the funded status with the consulting actuary.

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.

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.

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, 2005, stock appreciation rights (SARs) on 879,000 shares of common stock were not included in the computation of diluted EPS because the SARs' exercise prices were greater than the closing market price of HEI's common stock as of December 31, 2005 and, thus, the SARs were antidilutive. As of December 31, 2004 and 2003, all options and rights to purchase common stock and restricted stock were included in the computation of diluted EPS.

Stock compensation. For 2005, 2004 and 2003, 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) to account for its stock compensation (see "Recent accounting pronouncements and interpretations–Share-based payment" below).

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

Other-than-temporary impairment and its application to certain investments. In March 2004, FASB ratified EITF Issue No. 03-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments." EITF Issue No. 03-1 provides guidance for determining whether an investment in debt or equity securities is impaired, evaluating whether an impairment is other-than-temporary and measuring impairment. EITF Issue No. 03-1 also provides disclosure guidance. The recognition and measurement guidance would have applied prospectively to all current and future investments within the scope of EITF Issue No. 03-1 in reporting periods beginning after June 15, 2004. However, in September 2004, the FASB issued FASB Staff Position (FSP) EITF 03-1-1 to delay the effective date of the recognition and measurement guidance. At its June 29, 2005 meeting, the FASB decided not to provide additional guidance on the meaning of other-than-temporary impairment, but directed its staff to issue proposed FSP EITF 03-1-a as final (retitled as FSP FAS 115-1 and FAS 124-1). The guidance in FSP FAS 115-1 and FAS 124-1 addresses the determination of when an investment is considered impaired, whether that impairment is other than temporary, and the measurement of an impairment loss. The FSP also includes accounting considerations subsequent to the recognition of an other-than-temporary impairment and requires certain disclosures about unrealized losses that have not been recognized as other-than-temporary impairments. The guidance in this FSP amends FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities," and FASB Statement No. 124, "Accounting for Certain Investments Held by Not-for-Profit Organizations," and adds a footnote to APB Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." The guidance in this FSP nullifies certain requirements of EITF Issue No. 03-1 and supersedes EITF Abstracts, Topic D-44, "Recognition of Other-Than-Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value." The guidance in this FSP is required to be applied to reporting periods beginning after December 15, 2005. Because the impact of adopting the provisions of FSP FAS 115-1 will be dependent on future events and circumstances, management cannot predict such impact.

Medicare Prescription Drug, Improvement and Modernization Act of 2003. 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.

In May 2004, the FASB issued FSP No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," which was effective for the first interim or annual period beginning after June 15, 2004. When an employer is able to determine that benefits provided by its plan are actuarially equivalent to the Medicare Part D benefits, the FSP requires (a) treatment of the effects of the federal subsidy as an actuarial gain like similar gains and losses, and (b) certain financial statement disclosures related to the impact of the 2003 Act for employers that sponsor postretirement health care plans providing prescription drug benefits.

The accumulated postretirement benefit obligation for the Company's plans as of December 31, 2005 has been reduced by an estimated $3 million for the subsidy related to benefits attributed to past service. The net periodic postretirement benefit cost for 2006 has been reduced by an estimated $0.5 million for the subsidy.

Share-based payment. In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment," which requires companies to recognize the grant-date fair value of stock options and other equity-based compensation issued to employees in the income statement. In March 2005, the SEC issued Staff Accounting Bulletin (SAB) No. 107, which provides accounting, disclosure, valuation and other guidance related to share-based payment arrangements. The Company adopted the provisions of SFAS No. 123 (revised 2004) and the guidance in SAB No. 107 on January 1, 2006 and the net income impact of adoption was immaterial. Since the Company adopted the recognition provisions of SFAS No. 123 as of January 1, 2002, the only expense recognition change the Company made upon adoption of SFAS No. 123 (revised 2004) was how it accounts for forfeitures. Historically, forfeitures have not been significant.

Tax effects of income from domestic production activities. In December 2004, the FASB issued FSP No. 109-1, "Application of FASB Statement No. 109, *Accounting for Income Taxes,* for the Tax Deduction Provided to U.S. Based Manufacturers by the American Jobs Creation Act of 2004," which was effective upon issuance. FSP No. 109-1 clarifies that the new deduction for qualified domestic production activities should be accounted for as a special deduction under SFAS No. 109, and not as a tax-rate reduction, because the deduction is contingent on performing activities identified in the new tax law.

Management is currently reviewing various aspects of the American Jobs Creation Act of 2004 (the 2004 Act), including proposed regulations relating to the 2004 Act recently issued by the Internal Revenue Service. There are at least two provisions with potential implications for HECO and its subsidiaries:

1. Manufacturing tax incentives for the production of electricity beginning in 2005. Taxpayers will be able to deduct a percentage (3% in 2005 and 2006, 6% in 2007 through 2009, and 9% in 2010 and thereafter) of the lesser of their qualified production activities income or their taxable income.
2. Generally for electricity sold and produced after October 22, 2004, the 2004 Act expands the income tax credit for electricity produced from certain sources to include open-loop biomass, geothermal and solar energy, small irrigation power, landfill gas, trash combustion and qualifying refined coal production facilities.

These provisions had no impact on HECO's consolidated net income for 2005 and based on current estimates, management expects that the provisions will not have a significant impact on HECO's consolidated net income in the future, pending further guidance from the Internal Revenue Service.

Asset retirement obligations. In March 2005, the FASB issued FIN 47, "Accounting for Conditional Asset Retirement Obligations," which requires recognition of a liability for the fair value of a legal obligation to perform asset-retirement activities that are conditional on a future event if the amount can be reasonably estimated. The Company adopted the provisions of FIN 47 on December 31, 2005 and recorded an asset retirement obligation of $0.3 million for estimated remediation activities for certain transformers that contain polychlorinated biphenyl contaminated oil. The pro forma amounts of the asset retirement obligation, measured using information, assumptions, and interest rates as of December 31, 2005, would have been $0.3 million as of December 31, 2004 and 2003.

The electric utilities own assets for which the fair value of the asset retirement obligation cannot be reasonably determined because the asset-retirement activities associated with the legal obligation are contingent on future events which, at this time, cannot be reasonably determined. These assets include certain parts of a power plant and a fuel-oil pipeline which may be required to be dismantled upon retirement of another power plant. The electric utilities currently intend to operate these assets for the foreseeable future and because of the indeterminate retirement dates, are unable to reasonably estimate the fair value of any legal obligations. The asset retirement obligation for these assets will be recorded once the future events can be reasonably determined.

Accounting changes and error corrections. In June 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections." This new standard replaces APB Opinion No. 20, "Accounting Changes," and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." Among other changes, SFAS No. 154 requires that a voluntary change in accounting principle be applied retrospectively so that all prior period financial statements presented are based on the new accounting principle, unless it is impracticable to do so. SFAS No. 154 also provides that (1) a change in method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) correction of errors in previously issued financial statements should be termed a "restatement." SFAS No. 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005. Because the impact of adopting the provisions of SFAS No. 154 will be dependent on future events and circumstances, management cannot predict such impact.

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 2005 presentation. For example, assets and liabilities as of December 31, 2004 have been restated for the reclassification of regulatory assets from "Regulatory liabilities, net" to "Regulatory assets."

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, 2005, customer accounts receivable include unbilled energy revenues of $91 million on a base of annual revenue of $1.8 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 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. In 2004 PUC decisions approving the electric utilities' fuel supply contracts, the PUC affirmed the electric utilities' right to include in their respective energy cost adjustment clauses 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 energy cost adjustment clauses in rate cases.

HECO and its subsidiaries' operating revenues include amounts for various revenue taxes. Revenue taxes are recorded as an expense in the year the related revenues are recognized. Payments to the taxing authorities by HECO and its subsidiaries are based on the prior years' revenues. For 2005, 2004 and 2003, HECO and its subsidiaries included approximately $159 million, $136 million and $123 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 8.5%, 8.6% and 8.7% in 2005, 2004 and 2003, 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. Premiums are amortized and discounts are accreted 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 estimated inherent losses on 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. Since January 1, 2002, 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	2005		2004	
(in thousands)	Gross carrying amount	Accumulated amortization	Gross carrying amount	Accumulated amortization
Core deposit intangibles	$ 20,276	$ 16,932	$ 20,276	$ 15,201
Mortgage servicing rights	11,662	8,650	11,740	7,998
	$ 31,938	$ 25,582	$ 32,016	$ 23,199

Changes in the valuation allowance for MSRs were as follows:

(in thousands)		2005		2004		2003
Valuation allowance, January 1	$	701	$	2,316	$	2,215
Provision (reversal of allowance)		(359)		4		101
Other than temporary impairment		(135)		(1,619)		–
Valuation allowance, December 31	$	207	$	701	$	2,316

In 2005, 2004 and 2003, aggregate amortization expenses were $2.4 million, $3.2 million and $4.0 million, respectively.

The estimated aggregate amortization expense for ASB's core deposit intangibles and MSRs for 2006, 2007, 2008, 2009 and 2010 is $2.2 million, $2.0 million, $0.4 million, $0.3 million and $0.3 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 2005, 2004 and 2003, MSRs acquired through the sale or securitization of loans held for sale totaled $0.1 million, $0.4 million, and $1.2 million, respectively. Amortization expense for ASB's MSRs amounted to $0.7 million, $1.5 million, and $2.3 million for 2005, 2004 and 2003, respectively, and are recorded 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.

(in thousands)	Electric Utility	Bank	Other	Total
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
2003				
Revenues from external customers	$1,396,683	$ 371,320	$ 13,313	$1,781,316
Intersegment revenues (eliminations)	2	–	(2)	–
Revenues	1,396,685	371,320	13,311	1,781,316
Depreciation and amortization	118,792	30,748	859	150,399
Interest expense	44,341	123,324	24,951	192,616
Profit (loss)*	128,735	87,220	(33,540)	182,415
Income taxes (benefit)	49,824	30,959	(16,416)	64,367
Income (loss) from continuing operations	78,911	56,261	(17,124)	118,048
Capital expenditures	146,964	15,798	129	162,891
Assets (at December 31, 2003**)	2,687,798	6,515,208	104,694	9,307,700

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

Long-lived assets located in foreign countries as of the dates and for the periods identified above were not material.

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	2005	2004	2003
(in thousands)			
Revenues			
Operating revenues	$ 1,801,710	$ 1,546,875	$ 1,393,038
Other—nonregulated	4,674	3,796	3,647
	1,806,384	1,550,671	1,396,685
Expenses			
Fuel oil	639,650	483,423	388,560
Purchased power	458,120	398,836	368,076
Other operation	172,962	157,198	155,531
Maintenance	82,242	77,313	64,621
Depreciation	122,870	114,920	110,560
Taxes, other than income taxes	167,295	143,834	130,677
Other – nonregulated	1,542	1,244	2,095
	1,644,681	1,376,768	1,220,120
Operating income from regulated and nonregulated activities	161,703	173,903	176,565
Allowance for equity funds used during construction	5,105	5,794	4,267
Interest and other charges	(50,323)	(50,503)	(52,931)
Allowance for borrowed funds used during construction	2,020	2,542	1,914
Income before income taxes and preferred stock dividends of HECO	118,505	131,736	129,815
Income taxes	44,623	49,479	49,824
Income before preferred stock dividends of HECO	73,882	82,257	79,991
Preferred stock dividends of HECO	1,080	1,080	1,080
Net income for common stock	$ 72,802	$ 81,177	$ 78,911

Consolidated Balance Sheet Data

December 31	2005	2004
(in thousands)		
Assets		
Utility plant, at cost		
Property, plant and equipment	$ 3,782,565	$ 3,606,908
Less accumulated depreciation	(1,456,537)	(1,361,703)
Construction in progress	147,756	102,949
Net utility plant	2,473,784	2,348,154
Regulatory assets	110,718	108,630
Other	496,958	422,831
	$ 3,081,460	$ 2,879,615
Capitalization and liabilities		
Common stock equity	$ 1,039,259	$ 1,017,104
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	765,993	752,735
Total capitalization	1,839,545	1,804,132
Short-term borrowings from nonaffiliates and affiliate	136,165	88,568
Deferred income taxes	208,374	189,193
Regulatory liabilities	219,204	197,089
Contributions in aid of construction	256,263	235,505
Other	421,909	365,128
	$ 3,081,460	$ 2,879,615

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, 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.

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, 2005, if different. Regulatory liabilities were as follows:

December 31	2005	2004
(in thousands)		
Cost of removal in excess of salvage value (1 to 60 years)	$ 217,493	$ 197,089
Other (5 years; 2 to 5 years)	1,711	–
	$ 219,204	$ 197,089

Regulatory assets were as follows:

December 31	2005	2004
(in thousands)		
Income taxes, net (1 to 36 years)	$ 70,743	$ 68,780
Postretirement benefits other than pensions (18 years; 7 years)	12,528	14,318
Unamortized expense and premiums on retired debt and equity issuances (11 to 30 years; 1 to 23 years)	16,081	15,509
Integrated resource planning costs, net (1 year)	2,395	1,554
Vacation earned, but not yet taken (1 year)	5,669	5,011
Other (1 to 20 years)	3,302	3,458
	$ 110,718	$ 108,630

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% ($176 million), 10% ($148 million) and 10% ($135 million) of their operating revenues from the sale of electricity to various federal government agencies in 2005, 2004 and 2003, 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, 2006, the estimated cost of minimum purchases under the fuel supply contracts is $542 million each year for 2006 and 2007, $543 million for 2008, $542 million each year for 2009 and 2010 and a total of $2.2 billion for the period 2011 through 2014. The actual cost of purchases in 2006 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 $662 million, $490 million and $390 million of fuel under contractual agreements in 2005, 2004 and 2003, respectively.

Power purchase agreements (PPAs). As of December 31, 2005, HECO and its subsidiaries had six firm capacity PPAs for a total of 540 MW of firm capacity. Of the 540 MW of firm capacity under PPAs, approximately 91% is under PPAs with AES Hawaii, Inc. (PPA executed in March 1988), Kalaeloa Partners, L.P. (October 1988), Hamakua Energy Partners, L.P. (October 1997) and HPower (March 1986). The primary business activities of these six IPPs are the generation and sale of power to the electric utilities (and municipal waste disposal in the case of HPower). Purchases from these six IPPs and all other IPPs totaled $458 million, $399 million and $368 million for 2005, 2004 and 2003, 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 2006, $121 million in 2007, $119 million in 2008, $116 million in 2009, $119 million in 2010 and a total of $1.3 billion in the period from 2011 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 energy cost adjustment clause in their rate schedules. 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. As of December 31, 2005, HECO and its subsidiaries had recognized $32 million of revenues with respect to interim orders regarding certain integrated resource planning costs and an Oahu general rate increase, which revenues are subject to refund, with interest, if and to the extent they exceed the amounts allowed in final orders.

HELCO power situation.

Historical context. 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 megawatt (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."

Status. 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 opposes 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, CT-4 and CT-5 were installed and put into limited commercial operation in May and June 2004, respectively. The BLNR's construction deadline of July 31, 2005 has been met. Noise mitigation equipment has been installed on CT-4 and CT-5 and the need for additional noise mitigation work for CT-5 (not requiring any further construction) is being examined 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.

Currently, four appeals to the Hawaii Supreme Court by Waimana have been briefed and are awaiting decision. These are appeals to judgments of the Third Circuit Court involving (i) vacating of a November 2002 Final Judgment which had halted construction; (ii) the Board of Land and Natural Resources (BLNR) 2003 construction period extension; (iii) 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) appeals (now consolidated) by Waimana and another party of judgments upholding the BLNR's approval of the long-term lease allowing HELCO to use brackish well water. In the third appeal, additional briefs were filed on July 15, 2005 on the question of whether the appeal is moot given the granting by the BLNR of a long-term water lease allowing HELCO to use brackish water. Full implementation of the Settlement Agreement is conditioned on obtaining final dispositions of all litigation pending at the time of the Settlement Agreement. If the remaining dispositions are obtained, as HELCO believes they will be, then HELCO must undertake a number of actions under the Settlement Agreement, 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). Some of these actions have already commenced.

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 Land Use Commission, which was approved in October 2005. HELCO's plans for ST-7 are progressing, but construction cannot start until HELCO obtains County rezoning to a "General Industrial" classification and obtains the necessary permits. The application for rezoning was filed with the County in November 2005. In January 2006, the County Planning Commission recommended approval of the rezoning to the County Council. Further action by the County Council is pending.

Costs incurred; management's evaluation. As of December 31, 2005, 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 AFUDC up to November 30, 1998, after which date management decided not to continue accruing AFUDC. The $110 million of costs was reclassified from construction in progress to plant and equipment in 2004 and 2005 and depreciated beginning January 1 of the year following the reclassification.

Management believes that the prospects are good that the remaining Settlement Agreement conditions will be satisfied and that any further necessary permits will be obtained and that the appeals will be favorably resolved. However, HELCO's electric rates will not change specifically as a result of including CT-4 and CT-5 in plant and equipment until HELCO files a rate increase application and the PUC grants HELCO rate relief. In December 2005, HELCO notified the PUC that it intends to file a request for an electric rate increase in spring 2006 in part to recover CT-4 and CT-5 costs. While management believes that no adjustment to costs incurred to put CT-4 and CT-5 into service is required as of December 31, 2005, 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, but an application for a permit which would have allowed construction in the originally planned route through conservation district lands was denied in June 2002.

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 $57 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 has been completed and the PUC issued a Finding of No Significant Impact in April 2005. Subject to PUC approval, HECO plans to construct the revised project, none of which is in conservation district lands, in two phases, currently projected for completion in 2007 and 2009.

As of December 31, 2005, the accumulated costs recorded for the EOTP amounted to $26 million, including $12 million of planning and permitting costs incurred prior to 2003, when HECO was denied the approval necessary for the partial underground/partial overhead 138 kV line, $3 million of planning and permitting costs incurred after 2002, and $11 million for AFUDC. In the written testimony filed in June 2005, the Consumer Advocate's consultant 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. Just prior to the evidentiary hearing, the PUC approved that part of a stipulation between HECO and the Consumer Advocate that this proceeding should determine whether HECO should be given approval to expend funds for the EOTP provided 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 that 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). Management believes no adjustment to project costs is required as of December 31, 2005. 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.

State of Hawaii, *ex rel*., Bruce R. Knapp, *Qui Tam* Plaintiff, and Beverly Perry, on behalf of herself and all others similarly situated, Class Plaintiff, vs. The AES Corporation, AES Hawaii, Inc., HECO and HEI. In April 2002, HECO and HEI were served with an amended complaint filed in the First Circuit Court of Hawaii alleging that the State of Hawaii and HECO's other customers had been overcharged for electricity by over $1 billion since September 1992 due to alleged excessive prices in the PUC-approved amended PPA between HECO and AES Hawaii. The PUC proceedings in which the amended PPA was approved addressed a number of issues, including whether the terms and conditions of the PPA were reasonable.

As a result of rulings by the First Circuit Court in 2003, all claims for relief and causes of action in the amended complaint were dismissed. In October 2003, plaintiff Beverly Perry filed a notice of appeal to the Hawaii Supreme Court and the Intermediate Court of Appeals, on the grounds that the Circuit Court erred in its reliance on the doctrine of primary jurisdiction and the statute of limitations. On July 16, 2004, the Supreme Court retained jurisdiction of the appeal (rather than assign the appeal to the Intermediate Court of Appeals) and a decision is pending. In the opinion of management, the ultimate disposition of this matter will not have a material adverse effect on the Company's or HECO's consolidated financial position, results of operations or liquidity.

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 and 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.

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 DOH. Currently, the Participating Parties are preparing Remediation Alternatives Analyses, which will identify and recommend remedial approaches. HECO routinely maintains its facilities and has investigated its operations in the Iwilei area and ascertained that they are not releasing petroleum.

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 $0.6 million has been incurred through February 28, 2006). Because (1) the full scope and extent of additional investigative work, remedial activities and monitoring are unknown at this time, (2) the final cost allocation method among the PRPs has not yet been determined and (3) management cannot estimate the costs to be incurred (if any) for the sites other than the Iwilei Unit (including its Honolulu power plant site), the cost estimate may be subject to significant change and additional material investigative and remedial costs may be incurred.

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, MECO and HELCO will evaluate the impacts, if any, on them. If any of the utilities' units are ultimately required to install post-combustion control technologies to meet BART emission limits, the 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 new rule, which establishes location and technology-based design, construction and capacity standards for existing cooling water intake structures. These standards will apply to HECO's Kahe, Waiau and Honolulu generating stations unless the utility can demonstrate that at each facility implementation of these standards will result in very high costs or little environmental benefit. HECO has until March 2008 to make this showing or demonstrate compliance. HECO has retained a consultant to develop a cost effective compliance strategy and a preliminary assessment of technologies and operational measures. HECO is developing a monitoring program and plans to perform a cost-benefit analysis to demonstrate that HECO's existing intake systems have minimal environmental impacts, which demonstration would exempt HECO from the standards. Concurrently, HECO will evaluate alternative compliance mechanisms allowed by the rule, some of which could entail significant capital expenditures to implement.

Collective bargaining agreements. 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).

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 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.

4 • Bank subsidiary

Selected financial information

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

Consolidated Statements of Income Data

Years ended December 31 (in thousands)	2005	2004	2003
Interest and dividend income			
Interest and fees on loans	$ 205,084	$ 184,773	$ 198,948
Interest on mortgage-related securities	121,847	116,471	107,496
Interest and dividends on investment securities	4,077	5,876	6,384
	331,008	307,120	312,828
Interest expense			
Interest on deposit liabilities	52,064	47,184	53,808
Interest on Federal Home Loan Bank advances	44,699	43,301	48,280
Interest on securities sold under agreements to repurchase	24,663	22,302	21,236
	121,426	112,787	123,324
Net interest income	209,582	194,333	189,504
Provision (reversal of allowance) for loan losses	(3,100)	(8,400)	3,075
Net interest income after provision (reversal of allowance) for loan losses	212,682	202,733	186,429
Noninterest income			
Fees from other financial services	25,790	23,560	22,817
Fee income on deposit liabilities	16,989	17,820	16,971
Fee income on other financial products	9,058	10,184	9,920
Gain (loss) on sale of securities	175	(70)	4,085
Other income	4,890	5,670	4,699
	56,902	57,164	58,492
Noninterest expense			
Compensation and employee benefits	69,082	65,052	65,805
Occupancy	17,055	16,996	16,579
Equipment	13,722	13,756	13,967
Services	15,466	12,863	12,529
Data processing	10,598	11,794	10,668
Office supplies, printing and postage	4,440	4,699	4,850
Marketing	3,816	3,987	3,973
Communication	3,475	2,879	4,072
Other expense	27,029	22,897	19,723
	164,683	154,923	152,166
Income before minority interests and income taxes	104,901	104,974	92,755
Minority interests	45	97	124
Income taxes	39,969	58,404	30,959
Income before preferred stock dividends	64,887	46,473	61,672
Preferred stock dividends	4	5,411	5,411
Net income for common stock	$ 64,883	$ 41,062	$ 56,261

Consolidated Balance Sheet Data

December 31	2005	2004
(in thousands)		
Assets		
Cash and equivalents	$ 150,130	$ 120,295
Federal funds sold	57,434	41,491
Available-for-sale investment and mortgage-related securities	2,629,351	2,953,372
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,365
Loans receivable, net	3,566,834	3,249,191
Other	244,443	213,528
Goodwill and other intangibles	89,379	91,263
	$ 6,835,335	$ 6,766,505
Liabilities and stockholders' equity		
Deposit liabilities–noninterest-bearing	$ 624,497	$ 558,958
Deposit liabilities–interest-bearing	3,932,922	3,737,214
Securities sold under agreements to repurchase	686,794	811,438
Advances from Federal Home Loan Bank	935,500	988,231
Other	98,189	110,938
	6,277,902	6,206,779
Minority interests	–	3,415
Common stock	321,538	320,501
Retained earnings	272,545	243,001
Accumulated other comprehensive loss	(36,650)	(7,191)
	557,433	556,311
	$ 6,835,335	$ 6,766,505

Investment and mortgage-related securities. ASB owns one investment security (a federal agency obligation), 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, 2005, ASB's available-for-sale federal agency obligation had a contractual due date in November 2008. Contractual maturities are not presented for mortgage-related securities because these securities are not due at a single maturity date. 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, 2005

(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses — Less than 12 months: Count	Fair Value	Amount	12 months or longer: Count	Fair Value	Amount
Available-for-sale										
Investment security-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

(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses — Less than 12 months: Count	Fair Value	Amount	12 months or longer: Count	Fair Value	Amount
Available-for-sale										
Investment security-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)

December 31, 2003

(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses — Less than 12 months: Count	Fair Value	Amount	12 months or longer: Count	Fair Value	Amount
Available-for-sale										
Investment security-federal agency obligation	$ 49,833	$ 172	$ –	$ 50,005	–	$ –	$ –	–	$ –	$ –
Mortgage-related securities:										
FNMA, FHLMC and GNMA	2,359,398	21,651	(16,411)	2,364,638	79	1,267,557	(16,411)	–	–	–
Private issue	306,583	1,595	(6,197)	301,981	7	88,156	(1,339)	30	88,517	(4,858)
	$2,715,814	$23,418	$(22,608)	$2,716,624	86	$1,355,713	$(17,750)	30	$88,517	$(4,858)

As of December 31, 2005, 2004 and 2003, 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 2005, 2004 and 2003, proceeds from sales of available-for-sale mortgage-related securities were $28 million, $45 million and $243 million resulting in gross realized gains of $0.2 million, $0.2 million and $4.2 million and gross realized losses of nil, $0.3 million and $0.1 million, respectively.

ASB pledged mortgage-related securities with a carrying value of approximately $191 million and $125 million as of December 31, 2005 and 2004, 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, 2005 and 2004, mortgage-related securities with a carrying value of $800 million and $919 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, 2005 and 2004, 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	2005	2004
(in thousands)		
Real estate loans		
One-to-four unit residential and commercial	$ 2,844,347	$ 2,690,527
Construction and development	241,311	202,466
	3,085,658	2,892,993
Consumer loans	248,635	223,746
Commercial loans	412,816	310,999
	3,747,109	3,427,738
Undisbursed portion of loans in process	(140,273)	(132,211)
Deferred fees and discounts, including net purchase accounting discounts	(22,088)	(21,223)
Allowance for loan losses	(30,595)	(33,857)
Loans held for investment	3,554,153	3,240,447
Loans held for sale	12,681	8,744
	$ 3,566,834	$ 3,249,191

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, 2004, ASB had impaired loans totaling $24.1 million, which consisted of $5.6 million of commercial real estate loans and $18.5 million of commercial loans. As of December 31, 2005 and 2004, impaired loans totaling $0.3 million and $1.2 million, respectively, had related allowances for loan losses of $0.1 million and $0.2 million, respectively. As of December 31, 2005 and 2004, ASB had $20.2 million and $22.9 million of impaired loans, respectively, for which there were no related allowances for loan losses. ASB realized $1.4 million, $1.3 million and $1.7 million of interest income on impaired loans in 2005, 2004 and 2003, respectively. The average balances of impaired loans during 2005, 2004 and 2003 were $20.8 million, $20.2 million and $22.5 million, respectively.

As of December 31, 2005 and 2004, ASB had nonaccrual and renegotiated loans of $7.3 million and $11.7 million, respectively.

ASB realized $0.1 million, $0.4 million and $0.1 million of interest income on nonaccrual loans in 2005, 2004 and 2003 respectively. If these loans would have earned interest in accordance with their original contractual terms ASB would have realized $0.5 million, $0.6 million and $0.5 million in 2005, 2004 and 2003, respectively. ASB had no loans that were 90 days or more past due on which interest was being accrued as of December 31, 2005 and 2004.

As of December 31, 2005 and 2004, commitments not reflected in the consolidated balance sheets consisted of commitments to originate loans, other than the undisbursed portion of loans in process, of $76 million and $42 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, 2005 and 2004, ASB had commitments to sell residential loans of $2.5 million and $0.3 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, 2005, rate lock commitments were made on loans totaling $0.2 million. As of December 31, 2004, there were no rate lock commitments made on loans to be held for sale. 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, 2005 and 2004, the notional amounts for forward sales contracts were $2.5 million and $0.3 million, respectively. Valuation models are applied using current market information to estimate fair value. For 2005 and 2004, the net loss on derivatives was nil.

ASB had commitments to sell education loans of $10 million and $8 million, respectively, as of December 31, 2005 and 2004.

As of December 31, 2005 and 2004, standby, commercial and banker's acceptance letters of credit totaled $25 million and $40 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, 2005 and 2004, unused lines of credit totaled $867 million and $708 million, respectively.

ASB services real estate loans owned by third parties ($0.4 billion, $0.5 billion and $0.6 billion as of December 31, 2005, 2004 and 2003, 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, 2005 and 2004, ASB had pledged loans with an amortized cost of approximately $1.1 billion and $1.2 billion, respectively, as collateral to secure advances from the FHLB of Seattle.

As of December 31, 2005 and 2004, 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 $104 million and $74 million, respectively. The $30 million increase in such loans in 2005 was attributed to new loans of $41 million, repayments of $9 million and closed lines of credit of $2 million. As of December 31, 2005 and 2004, $87 million and $58 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)	2005	2004	2003
Allowance for loan losses, January 1	$ 33,857	$ 44,285	$ 45,435
Provision (reversal of allowance) for loan losses	(3,100)	(8,400)	3,075
Charge-offs, net of recoveries			
Real estate loans	(459)	(868)	(604)
Other loans	621	2,896	4,829
Net charge-offs	162	2,028	4,225
Allowance for loan losses, December 31	$ 30,595	$ 33,857	$ 44,285
Ratio of net charge-offs to average loans outstanding	NM	0.06%	0.14%

NM Not meaningful.

Deposit liabilities

December 31	2005		2004	
(dollars in thousands)	Weighted-average stated rate	Amount	Weighted-average stated rate	Amount
Savings	0.63%	$ 1,723,949	0.40%	$ 1,700,211
Other checking				
Interest-bearing	0.13	573,442	0.06	534,464
Noninterest-bearing	–	309,172	–	256,346
Commercial checking	–	315,325	–	302,612
Money market	1.18	257,144	0.58	303,162
Term certificates	3.18	1,378,387	3.26	1,199,377
	1.28%	$ 4,557,419	1.12%	$ 4,296,172

As of December 31, 2005 and 2004, certificate accounts of $100,000 or more totaled $406 million and $303 million, respectively.

The approximate amounts of term certificates outstanding as of December 31, 2005 with scheduled maturities for 2006 through 2010 were $801 million maturing in 2006, $200 million in 2007, $105 million in 2008, $77 million in 2009 and $177 million in 2010.

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

Years ended December 31	2005	2004	2003
(in thousands)			
Term certificates	$ 40,063	$ 38,935	$ 43,413
Savings	8,860	6,525	7,524
Money market	2,582	1,448	2,424
Interest-bearing checking	559	276	447
	$ 52,064	$ 47,184	$ 53,808

Securities sold under agreements to repurchase

December 31, 2005

Maturity	Repurchase liability	Weighted-average interest rate	Collateralized by mortgage-related securities– fair value plus accrued interest
(dollars in thousands)			
Overnight	$ 91,508	3.32%	$122,667
1 to 29 days	66,423	3.99	86,319
30 to 90 days	81,866	4.14	106,387
Over 90 days	446,997	3.85	487,495
	$686,794	3.83%	$802,868

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	2005	2004	2003
(dollars in millions)			
Amount outstanding as of December 31	$687	$811	$831
Average amount outstanding	$705	$842	$807
Maximum amount outstanding as of any month-end	$828	$990	$958
Weighted-average interest rate as of December 31	3.83%	3.44%	2.50%
Weighted-average interest rate during the year	3.50%	2.65%	2.63%
Weighted-average remaining days to maturity as of December 31	423	500	640

Advances from Federal Home Loan Bank

December 31, 2005	Weighted-average stated rate	Amount
(dollars in thousands)		
Due in		
2006	3.66%	$ 205,500
2007	4.09	299,000
2008	5.44	168,000
2009	4.60	163,000
2010	6.03	100,000
	4.53%	$ 935,500

As of December 31, 2005, $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, 2005 and 2004.

Common stock equity. As of December 31, 2005, 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, 2005, 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 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 $29 million increase in accumulated other comprehensive loss from December 31, 2004 to December 31, 2005 was primarily due to the change in the market value of the available-for-sale 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, MECO and HELCO under an expense agreement and HECO's obligations under its trust guarantee and its guarantee of the obligations of MECO and HELCO 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, 2005 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 2005 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.

Kalaeloa Partners, L.P. In October 1988, HECO entered into a PPA with Kalaeloa Partners, L.P. (Kalaeloa), 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, which together effectively increased the firm capacity from 180 MW to 208 MW. The PPA and amendments have been approved by the PUC. 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 Qualified Facility under the Public Utilities Regulatory Policies Act of 1978.

Pursuant to the provisions of FIN 46R, HECO is deemed to have a variable interest in Kalaeloa via 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 Kalaeloa'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 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 energy cost adjustment clause to the extent the fuel and fuel related energy payments are not included in base energy rates.

6 • Short-term borrowings

Short-term borrowings as of December 31, 2005 consisted of commercial paper issued by HEI and HECO and had a weighted-average interest rate of 4.47%. Short-term borrowings as of December 31, 2004 consisted of commercial paper issued by HECO and had a weighted-average interest rate of 2.50%.

As of December 31, 2005 and 2004, HEI maintained bank lines of credit which totaled $80 million ($20 million maturing in April 2006, $15 million in May 2006, $15 million in October 2006 and $30 million in December 2006) and $80 million, respectively, and HECO maintained bank lines of credit which totaled $180 million ($90 million maturing in April 2006, $60 million in May 2006 and $30 million in August 2006) and $110 million, respectively. HEI maintains lines of credit at a base rate (Prime, Fed Funds, Bank Base or London Interbank Offered Rate) plus a margin (ranging from 0 to 125 basis points) and HECO maintains lines of credit at a base rate (Prime, Fed Funds, Bank Base, Bank Quoted or London Interbank Offered Rate) plus a margin (ranging from 0 to 81 basis points) to support the issuance of commercial paper and for other general corporate purposes. Fees to maintain the lines of credit are not material. Lines of credit maintained by HEI have covenants, including covenants related to capitalization ratios, consolidated net worth, maintaining 100% ownership of HECO and its subsidiaries and ASB remaining "well-capitalized." Lines of credit to HEI totaling $30 million contain provisions for revised pricing in the event of a ratings change. Lines of credit maintained by HECO have covenants, including covenants related to capitalization ratios. None of the lines are secured. There were no borrowings under any line of credit during 2005 and 2004.

7 • Long-term debt

December 31		2005		2004
(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		71,500
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
6.60%, refunded 2005		–		47,000
		717,900		717,900
Less funds on deposit with trustees		–		(12,462)
Less unamortized discount		(3,453)		(4,249)
		714,447		701,189
HEI medium-term notes 4.00-7.56%, due in various years through 2014		377,000		414,000
	$	1,142,993	$	1,166,735

As of December 31, 2005, the aggregate principal payments required on long-term debt for 2006 through 2010 are $110 million in 2006, $10 million in 2007, $50 million in 2008 and nil in 2009 and 2010.

8 • Retirement benefits

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 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. See "Medicare Prescription Drug, Improvement and Modernization Act of 2003" under "General—Recent accounting pronouncements and interpretations" in Note 1.

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.

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

	Pension benefits		Other benefits	
(in thousands)	2005	2004	2005	2004
Benefit obligation, January 1	$ 893,638	$ 828,300	$ 200,182	$ 180,108
Service cost	29,369	26,454	5,248	4,530
Interest cost	52,120	50,654	11,104	10,770
Amendments	123	83	–	(1,261)
Actuarial (gain) loss	28,422	28,679	(17,080)	14,083
Benefits paid and expenses	(42,555)	(40,532)	(8,540)	(8,048)
Benefit obligation, December 31	961,117	893,638	190,914	200,182
Fair value of plan assets, January 1	781,758	723,854	109,484	98,189
Actual return on plan assets	56,621	70,700	7,965	9,993
Employer contribution	14,126	27,736	10,716	9,350
Benefits paid and expenses	(42,555)	(40,532)	(8,540)	(8,048)
Fair value of plan assets, December 31	809,950	781,758	119,625	109,484
Funded status	(151,167)	(111,880)	(71,290)	(90,698)
Unrecognized net actuarial loss	266,784	226,936	24,871	40,505
Unrecognized net transition obligation	18	23	21,966	25,104
Unrecognized prior service cost (gain)	(4,949)	(5,695)	157	170
Net amount recognized, December 31	$ 110,686	$ 109,384	$ (24,296)	$ (24,919)
Amounts recognized in the balance sheet consist of:				
Prepaid benefit cost	$ 122,206	$ 119,552	$ –	$ –
Accrued benefit liability	(13,929)	(12,136)	(24,296)	(24,919)
Intangible asset	351	151	–	–
Accumulated other comprehensive income	2,058	1,817	–	–
Net amount recognized, December 31	$ 110,686	$ 109,384	$ (24,296)	$ (24,919)

The dates used to determine retirement benefit measurements for the defined benefit plans were December 31 of 2005, 2004 and 2003.

The defined benefit pension plans' accumulated benefit obligations, which do not consider projected pay increases, as of December 31, 2005 and 2004 were $806 million and $750 million, respectively. Depending on the performance of the pension plan assets, the status of interest rates and numerous other factors, including changes in accounting standards, the Company could be required to recognize an additional minimum liability as prescribed by SFAS No. 87, “Employers’ Accounting for Pensions,” in the future. If recognizing a liability is required, the liability would largely be recorded as a reduction to stockholders’ equity through a non-cash charge to accumulated other comprehensive income, but would also result in the removal of the prepaid pension asset ($122 million as of December 31, 2005) from the Company’s balance sheet.

In December 2005, the electric utilities submitted a request to the PUC for approval to record, as a regulatory asset pursuant to SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation,” and include in rate base the amount that would otherwise be charged to AOCI as required under the provisions of SFAS No. 87 in the event the electric utilities were required to record a minimum pension liability on the measurement date, and to allow the electric utilities to continue to maintain, in subsequent years, a regulatory asset in rate base, for any pension liability that would otherwise be charged to AOCI. Under such an accounting treatment, if in later years the fair values of the electric utilities’ pension assets were to exceed their accumulated benefit obligations, the electric utilities would reverse the regulatory assets and associated remaining minimum liabilities. Although this relief was not necessary for 2005 because the fair value of the utilities’ pension assets on December 31, 2005 exceeded the accumulated benefit obligation, such relief may be necessary in future years. Management cannot predict whether the PUC will approve this request, or when a decision will be made.

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 was based on an asset/liability study performed by the plans’ investment consultants, which projected the return over the long term to be in excess of 9%, based on the target asset allocation.

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

	Pension benefits				Other benefits			
			Investment policy [2]				Investment policy [2]	
December 31	2005	2004	Target	Range	2005	2004	Target	Range
Asset category								
Equity securities	69%	73%	70%	65-75%	68%	73%	70%	65-75%
Debt securities	29	25	30	25-35%	31	26	30	25-35%
Other [1]	2	2	–	–	1	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.

2 As of December 31, 2005.

The Company’s current estimate of contributions to the retirement benefit plans in 2006 is $14 million.

As of December 31, 2005, the benefits expected to be paid under the retirement benefit plans in 2006, 2007, 2008, 2009, 2010 and 2011 through 2015 amounted to $54 million, $57 million, $59 million, $61 million, $63 million and $360 million, respectively.

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

	Pension benefits			Other benefits		
December 31	2005	2004	2003	2005	2004	2003
Benefit obligation						
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
Net periodic benefit cost (years ended)						
Discount rate	6.00	6.25	6.75	6.00	6.25	6.75
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, 2005, the assumed health care trend rates for 2005 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%. As of December 31, 2004, the assumed health care trend rates for 2005 and future years were as follows: medical, 10.00%, grading down to 5.00% for 2010 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	2005	2004	2003	2005	2004	2003
(in thousands)						
Service cost	$ 29,369	$ 26,454	$ 22,918	$ 5,248	$ 4,530	$ 3,580
Interest cost	52,120	50,654	47,970	11,104	10,770	10,408
Expected return on plan assets	(73,971)	(72,880)	(59,790)	(9,853)	(9,690)	(7,639)
Amortization of unrecognized transition obligation	5	4	954	3,138	3,138	3,278
Amortization of prior service cost (gain)	(623)	(587)	(614)	13	13	13
Recognized actuarial loss	5,924	1,160	4,035	442	–	–
Net periodic benefit cost	$ 12,824	$ 4,805	$ 15,473	$10,092	$ 8,761	$ 9,640

Of the net periodic pension benefit costs, the Company recorded expense of $11 million, $5 million, $13 million in 2005, 2004 and 2003, respectively, and charged the remaining amounts primarily to electric utility plant. Of the net periodic other than pension benefit costs, the Company expensed $8 million, $6 million and $7 million in 2005, 2004 and 2003, 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 $16 million, $14 million and nil, respectively, as of December 31, 2005 and $15 million, $12 million and nil, respectively, as of December 31, 2004.

The health care cost trend rate assumptions can have a significant effect on the amounts reported for other benefits. As of December 31, 2005, a one-percentage-point increase in the assumed health care cost trend rates would have increased the total service and interest cost by $0.5 million and the postretirement benefit obligation by $4.3 million, and a one-percentage-point decrease would have reduced the total service and interest cost by $0.5 million and the postretirement benefit obligation by $4.6 million.

9 • Stock compensation

Under the 1987 Stock Option and Incentive Plan, as amended, HEI may issue an aggregate of 9,300,000 shares of common stock (5,435,138 shares unissued as of December 31, 2005) to officers and key employees as incentive stock options, nonqualified stock options, restricted stock, SARs, stock payments or dividend equivalents. HEI has issued nonqualified stock options, SARs, restricted stock and dividend equivalents.

For the nonqualified stock options and SARs, the exercise price of each option or SAR generally equals the fair market value of HEI's stock on or near the date of grant. Options and SARs and related dividend equivalents issued in the form of stock awarded 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 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. The Company recorded stock option and SARs compensation expense of $3.4 million in 2005, $1.6 million in 2004 and $2.0 million in 2003.

In December 2005, to accommodate changes to the tax rules imposed by the new Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), the Company modified the provisions for paying dividend equivalents on shares underlying nonqualified stock options and SARs that were vested on December 31, 2004, and the Company similarly modified provisions for paying dividend equivalents on dividends declared after 2004. Before modification, dividend equivalents were paid when and to the extent that the employee exercised the nonqualified stock options/SARs. In order to comply with Section 409A any vested dividend equivalent subject to the modification will be paid not later than 2½ months after the year in which the underlying dividend equivalent is declared (without regard to whether the underlying nonqualified stock option/SAR is exercised). The amount of such dividend equivalent payment generally is reduced if, as of December 31 for the year the payment is made, the per share exercise price of the underlying nonqualified stock option/SAR exceeds the fair market value per share of the underlying common stock.

Nonqualified stock options. Information about HEI's nonqualified stock options are summarized as follows:

	2005		2004		2003	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	1,122,500	$19.74	1,476,600	$19.02	1,266,050	$18.31
Granted	–	–	–	–	456,000	20.49
Exercised	(193,500)	19.07	(348,100)	16.67	(241,450)	18.08
Forfeited or expired	–	–	(6,000)	19.86	(4,000)	19.14
Outstanding, December 31	929,000	$19.88	1,122,500	$19.74	1,476,600	$19.02
Options exercisable, December 31	651,500	$19.51	568,000	$19.06	591,100	$17.60

(1) Weighted-average exercise price

	Outstanding				Exercisable	
Year of grant	Range of exercise prices	Number of options as of 12/31/05	Weighted-average remaining contractual life	Weighted-average exercise price	Number of options as of 12/31/05	Weighted-average exercise price
1997	$ 17.31	6,000	1.3	$17.31	6,000	$17.31
1998	20.50	6,000	2.3	20.50	6,000	20.50
1999	17.61 - 17.63	65,000	3.5	17.62	65,000	17.62
2000	14.74	52,000	4.3	14.74	52,000	14.74
2001	17.96	140,500	5.3	17.96	140,500	17.96
2002	21.68	250,000	6.3	21.68	186,500	21.68
2003	20.49	409,500	7.3	20.49	195,500	20.49
	$14.74 – 21.68	929,000	6.3	$19.88	651,500	$19.51

The weighted-average fair value of each option granted was $4.11 (at grant date) in 2003. The 2003 weighted-average assumptions used to estimate fair value include: risk-free interest rate of 3.0%; expected volatility of 18.4%; expected dividend yield of 6.6%; term of 10 years and expected life of 4.5 years. The weighted-average fair value of each option grant is estimated on the date of grant using a Binomial Option Pricing Model. See "Section 409A modification" below for discussion of 2005 grant modification of options granted in 2003.

Stock appreciation rights. Information about HEI's stock appreciation rights are summarized as follows:

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

(1) Weighted-average exercise price

		Outstanding			Exercisable	
Year of grant	Range of exercise prices	Number of underlying shares of SARs at 12/31/05	Weighted-average remaining contractual life	Weighted-average exercise price	Number of underlying shares of SARs at 12/31/05	Weighted-average exercise price
2004	$ 26.02	325,000	8.3	$26.02	81,250	$26.02
2005	26.18	554,000	9.3	26.18	–	26.18
	$26.02 –26.18	879,000	9.0	$26.12	81,250	$26.02

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, and term of 10 years and expected life of 4.5 years for both years. The weighted-average fair value of each SARs grant is estimated on the date of grant using a Binomial Option Pricing Model. As of December 31, 2005, unexercised SARs have exercise prices ranging from $26.02 to $26.18 per SAR and a weighted-average remaining contractual life of 9.0 years. See below for discussion of 2004 and 2005 grant modification.

Section 409A modification. 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 nonqualified stock options and SARs held by employees under the 1987 HEI Stock Option and Incentive Plan, as amended. The modifications apply to the nonqualified stock options granted in 2001, 2002, and 2003 and the SARs granted in 2004 and 2005.

The assumptions used to estimate fair value at the time of the Section 409A modification for 2003 nonqualified stock options and the 2004 and 2005 SARs include: risk-free interest rate of 4.4%, expected volatility of 14.9%, expected dividend yield of 4.6%. The expected life used at the time of modification was 4.2, 3.8, and 3.3 years for 2005, 2004, and 2003, respectively. Information about the modifications are summarized as follows:

	2005 SAR grant	2004 SAR grant	2003 option grant
Fair value of modified SAR/option as of December 7, 2005	$5.07	$4.34	$7.36
Less fair value of original SAR/option as of December 7, 2005	4.95	4.25	7.04
Additional compensation cost to be recognized per grant	$0.12	$0.09	$0.32

The additional compensation cost for the Section 409A modification was not material.

Restricted stock. Restricted stock grants generally becomes 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 method of accounting in the amounts of $0.2 million in 2005, $0.2 million in 2004 and $0.1 million in 2003.

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

	2005		2004		2003	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	34,000	$22.58	28,000	$22.17	18,000	$23.01
Granted	9,000	26.06	6,000	24.48	10,000	20.65
Restrictions ended	(2,000)	19.29	–	–	–	–
Outstanding, December 31	41,000	$23.50	34,000	$22.58	28,000	$22.17

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

10 • Income taxes

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

Years ended December 31	2005	2004	2003
(in thousands)			
Federal			
Current	$ 66,819	$ 42,142	$ 58,763
Deferred	(1,226)	15,670	3,032
Deferred tax credits, net	(1,351)	(1,446)	(1,504)
	64,242	56,366	60,291
State			
Current	3,586	32,809	2,213
Deferred	2,619	(1,875)	1,307
Deferred tax credits, net	3,453	5,180	556
	9,658	36,114	4,076
	$ 73,900	$ 92,480	$ 64,367

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	2005	2004	2003
(in thousands)			
Amount at the federal statutory income tax rate	$ 70,471	$ 70,077	$ 63,845
Increase (decrease) resulting from:			
State income taxes, net of effect on federal income taxes and excluding cumulative bank franchise taxes through December 31, 2003	6,278	3,133	2,649
Cumulative bank franchise taxes through December 31, 2003	–	20,340	–
Other, net	(2,849)	(1,070)	(2,127)
	$ 73,900	$ 92,480	$ 64,367

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

December 31	2005	2004
(in thousands)		
Deferred tax assets		
Cost of removal in excess of salvage value	$ 85,292	$ 76,687
Contributions in aid of construction and customer advances	38,406	39,159
Allowance for loan losses	11,886	13,841
Net unrealized losses on available-for-sale mortgage-related securities	24,087	2,083
Other	30,247	38,764
	189,918	170,534
Deferred tax liabilities		
Property, plant and equipment	271,949	249,790
Leveraged leases	8,444	29,920
Pension	45,401	42,240
Goodwill	10,652	8,745
Regulatory assets, excluding amounts attributable to property, plant and equipment	27,588	26,756
FHLB stock dividend	20,552	21,690
Other	13,329	21,158
	397,915	400,299
Net deferred income tax liability	$ 207,997	$ 229,765

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 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 audit issues with the Internal Revenue Service (IRS). In the fourth quarter of 2005, additional IRS audit issues were resolved, resulting in the reversal of $1 million of interest, net of taxes.

As of December 31, 2005, $2 million, net of tax effects, was accrued for unresolved tax issues and related interest. Although not probable, adverse developments on unresolved 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 unresolved 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 2005, 2004 and 2003, the Company paid interest amounting to $192 million, $185 million and $196 million, respectively.

In 2005, 2004 and 2003, the Company paid income taxes amounting to $45 million, $42 million and $53 million, respectively.

Supplemental disclosures of noncash activities. Under the HEI Dividend Reinvestment and Stock Purchase Plan, common stock dividends reinvested by shareholders in HEI common stock in noncash transactions amounted to $5 million in 2004 and $17 million in 2003. Since March 2004, HEI has been satisfying the requirements of the HEI DRIP and the Hawaiian Electric Industries Retirement Savings Plan by acquiring for cash its common shares through open market purchases rather than the issuance of additional shares.

In 2005, 2004 and 2003, other noncash increases in common stock for director and officer compensatory plans were $4.9 million, $2.9 million and $2.8 million, respectively.

In 2005, 2004 and 2003, HECO and its subsidiaries capitalized as part of the cost of electric utility plant an allowance for equity funds used during construction amounting to $5 million, $6 million and $4 million, respectively.

In 2005, 2004 and 2003, the estimated fair value of noncash contributions in aid of construction amounted to $12 million, $5 million and $14 million, respectively.

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

In 2003, ASB restructured a total of $389 million of FHLB advances with lower rate, longer maturity advances.

Revised cash flows from discontinued operations. The Company has separately disclosed the operating and investing portion of the cash flows attributable to its discontinued operations for 2004 and 2003, which in prior periods were reported on a combined basis as a single amount. For 2005, 2004 and 2003, there were no cash flows from financing activities from the Company's discontinued operations.

12 • Regulatory restrictions on net assets

As of December 31, 2005, 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, 2005, ASB could transfer approximately $166 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, 2005, 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, 2005, 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 has been reported as a discontinued operation in the Company's consolidated statements of income.

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	2005	2004	2003
(in thousands)			
Disposal			
Gain (loss), including a provision of $1 million for losses from operations during phase-out period in 2005, 2004 and 2003	$ (1,237)	$ 2,878	$ (6,017)
Income tax benefits (income taxes)	482	(965)	2,147
Gain (loss) on disposal	$ (755)	$ 1,913	$ (3,870)

As of December 31, 2005, 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.

Securities sold under agreements to repurchase. Fair value was estimated by discounting future cash flows using the current rates available for repurchase agreements with similar terms and remaining maturities.

Advances from Federal Home Loan Bank and long-term debt. Fair value was estimated by discounting the future cash flows using the current rates available for borrowings with 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	2005		2004	
(in thousands)	Carrying or notional amount	Estimated fair value	Carrying or notional amount	Estimated fair value
Financial assets				
Cash and equivalents	$ 151,513	$ 151,513	$ 132,138	$ 132,138
Federal funds sold	57,434	57,434	41,491	41,491
Available-for-sale investment and mortgage-related securities	2,629,351	2,629,351	2,953,372	2,953,372
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764	97,365	97,365
Loans receivable, net	3,566,834	3,534,583	3,249,191	3,278,170
Financial liabilities				
Deposit liabilities	4,557,419	4,532,420	4,296,172	4,297,681
Securities sold under agreements to repurchase	686,794	680,374	811,438	813,897
Advances from Federal Home Loan Bank	935,500	936,824	988,231	1,016,188
Long-term debt	1,142,993	1,171,092	1,166,735	1,214,226
Off-balance sheet items				
Loans serviced for others	358,565	4,611	452,724	5,292
HECO-obligated preferred securities of trust subsidiary	50,000	51,400	50,000	52,400

As of December 31, 2005 and 2004, loan commitments and unused lines and letters of credit had carrying amounts of $1.1 billion and $922 million and the estimated fair value was $0.6 million and $0.3 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
2005					
Revenues	$ 472,628	$ 522,262	$ 595,915	$ 624,759	$ 2,215,564
Operating income [1]	56,671	61,449	77,239	76,063	271,422
Net income (loss) [1]					
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
2004					
Revenues	$ 437,110	$ 461,798	$ 506,759	$ 518,390	$ 1,924,057
Operating income [2]	67,837	66,946	81,686	54,491	270,960
Net income [2]					
Continuing operations	30,932	11,238	40,759	24,810	107,739
Discontinued operations	–	–	1,913	–	1,913
	30,932	11,238	42,672	24,810	109,652
Basic earnings per common share [3]					
Continuing operations	0.40	0.14	0.51	0.31	1.36
Discontinued operations	–	–	0.02	–	0.02
	0.40	0.14	0.53	0.31	1.38
Diluted earnings per common share [4]					
Continuing operations	0.40	0.14	0.51	0.31	1.36
Discontinued operations	–	–	0.02	–	0.02
	0.40	0.14	0.53	0.31	1.38
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [5]					
High	26.88	26.28	26.75	29.55	29.55
Low	23.55	22.96	24.89	26.48	22.96

[1] 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.

[2] For 2004, amounts for the second quarter include an after-tax charge to net income of $24 million for the potential cumulative bank franchise tax liability ($21 million) and interest ($3 million) since ASB's REIT subsidiary was formed through March 31, 2004. For 2004, the amounts for the fourth quarter include $3 million in additional net income, representing a partial reversal of the $24 million previously charged to net income. See Note 10. Also, for 2004, the amounts for the fourth quarter include $16 million higher electric utility other operation and maintenance expenses due in part to larger scope and timing of overhauls, more repairs and maintenance, information technology system enhancements expenses, additions to insurance reserves and expenses related to compliance with the Sarbanes-Oxley Act of 2002.

[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.

HEI Directors

Robert F. Clarke, 63 (1)* **
Chairman, President and
Chief Executive Officer
Hawaiian Electric Industries, Inc.
1989

Don E. Carroll, 64 (3)*
Retired Chairman
Oceanic Cablevision
(cable television broadcasting)
1996

Shirley J. Daniel, Ph.D., 52 (2)*
Professor of Accountancy
University of Hawaii-Manoa
(higher education)
2002

Admiral Thomas B. Fargo,
USN (Retired), 57 (2)*
Chairman, LOEA Corporation and
SAGO Systems
(high-technology R&D)
Former Commander of the
U.S. Pacific Command
2005

Victor Hao Li, S.J.D., 64 (3)*
Co-chairman
Asia Pacific Consulting Group
(international business consultant)
1988

Bill D. Mills, 54 (1, 3, 4)
Chairman
The Mills Group
(real estate development)
1988

A. Maurice Myers, 65 (3)*
Retired Chairman, President and
Chief Executive Officer
Waste Management, Inc.
(environmental services)
1991

Diane J. Plotts, 70 (1, 2, 3)*
Business Advisor
1987

James K. Scott, Ed.D., 54*
President
Punahou School
(private education)
1995

Kelvin H. Taketa, 51 (4)*
President and Chief Executive Officer
Hawaii Community Foundation
(statewide charitable foundation)
1993

Barry K. Taniguchi, 58 (2)*
President and Chief Executive Officer
KTA Super Stores
(retail super markets-island of Hawaii)
2004

Jeffrey N. Watanabe, 63 (4)* ***
Senior Partner
Watanabe Ing & Komeiji LLP
(private law firm)
1987

Committees of the Board of Directors

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

Information as of March 6, 2006.
Year denotes year of first election to the board of directors.
* Also member of one or more subsidiary and/or advisory boards.
** Has announced retirement effective in May 2006.
*** Named by the HEI Board of Directors to succeed Robert F. Clarke on May 2, 2006 as HEI Chairman.

HEI Executive Officers and Subsidiary Presidents

Robert F. Clarke, 63*
Chairman, President and
Chief Executive Officer
1987

Andrew I. T. Chang, 66
Vice President–Government Relations
1985

Curtis Y. Harada, 50
Controller
1989

Constance H. Lau, 53**
President and Chief Executive Officer
American Savings Bank, F.S.B.
1984

Warren H. W. Lee, 58
President
Hawaii Electric Light Company, Inc.
1972

T. Michael May, 59
President and Chief Executive Officer
Hawaiian Electric Company, Inc.
1992

Edward L. Reinhardt, 53
President
Maui Electric Company, Limited
1986

Charles F. Wall, 66*
Vice President and
Corporate Information Officer
1990

Patricia U. Wong, 49
Vice President–Administration and
Corporate Secretary
1990

Eric K. Yeaman, 38
Financial Vice President, Treasurer
and Chief Financial Officer
2003

Information as of March 6, 2006.
Year denotes year of first employment by the Company.
* Has announced retirement effective in May 2006.
** Named by the HEI Board of Directors to succeed Robert F. Clarke on May 2, 2006 as HEI President and Chief Executive Officer and HECO Chairman.

Shareholder Information

CORPORATE HEADQUARTERS

Hawaiian Electric Industries, Inc.
900 Richards Street, Honolulu, Hawaii 96813,
Telephone: 808-543-5662, Facsimile: 808-543-7966

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, Facsimile: 808-532-5868
E-mail: invest@hei.com, Office hours: 7:30 a.m. to 4:00 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 2005 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.

COMPANY NEWS ON CALL 888-943-4329

Our toll free, automated voice response system allows shareholders to listen to recorded dividend and earnings information, news releases, stock quotes and the answers to frequently asked shareholder questions, or to request mailed copies of various documents.

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 or about the 15th of February, May, August and November.

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, May 2, 2006, 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, Facsimile: 808-543-7966
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 2005 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 4, 2005, of the CEO certifying that he is not aware of any violation by the Company of the New York Stock Exchange corporate governance listing standards.