HAWAIIAN ELECTRIC CO INC
Form 10-Q
November 03, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2010

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Exact Name of Registrant as Specified in Its Charter	Commission File Number	I.R.S. Employer Identification No.
HAWAIIAN ELECTRIC INDUSTRIES, INC.	**1-8503**	**99-0208097**
and Principal Subsidiary		
HAWAIIAN ELECTRIC COMPANY, INC.	**1-4955**	**99-0040500**

State of Hawaii

(State or other jurisdiction of incorporation or organization)

900 Richards Street, Honolulu, Hawaii 96813

(Address of principal executive offices and zip code)

Hawaiian Electric Industries, Inc. ----- (808) 543-5662

Hawaiian Electric Company, Inc. ------- (808) 543-7771

(Registrant s telephone number, including area code)

Not applicable

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

APPLICABLE ONLY TO CORPORATE ISSUERS:

Indicate the number of shares outstanding of each of the issuers classes of common stock, as of the latest practicable date.

Class of Common Stock	Outstanding October 29, 2010
Hawaiian Electric Industries, Inc. (Without Par Value)	94,157,246 Shares
Hawaiian Electric Company, Inc. ($6-2/3 Par Value)	13,786,959 Shares (not publicly traded)

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company o

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Hawaiian Electric Company, Inc. and Subsidiaries

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Hawaiian Electric Industries, Inc. and Subsidiaries

Hawaiian Electric Company, Inc. and Subsidiaries

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GLOSSARY OF TERMS

Terms	Definitions
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income
AOS	Adequacy of supply
ASB	American Savings Bank, F.S.B., a wholly-owned subsidiary of American Savings Holdings, Inc. and parent company of American Savings Investment Services Corp. (and its subsidiary, Bishop Insurance Agency of Hawaii, Inc., substantially all of whose assets were sold in 2008).
ASHI	American Savings Holdings, Inc., a wholly owned subsidiary of Hawaiian Electric Industries, Inc. and the parent company of American Savings Bank, F.S.B.
CEIS	Clean energy infrastructure surcharge
CHP	Combined heat and power
CIP CT-1	Campbell Industrial Park combustion turbine No. 1
Company	When used in Hawaiian Electric Industries, Inc. sections, the Company refers to Hawaiian Electric Industries, Inc. and its direct and indirect subsidiaries, including, without limitation, Hawaiian Electric Company, Inc. and its subsidiaries (listed under HECO); American Savings Holdings, Inc. and its subsidiary, American Savings Bank, F.S.B. and its subsidiaries (listed under ASB); Pacific Energy Conservation Services, Inc.; HEI Properties, Inc.; HEI Investments, Inc. (dissolved in 2008); Hawaiian Electric Industries Capital Trust II and Hawaiian Electric Industries Capital Trust III (inactive financing entities); and The Old Oahu Tug Service, Inc. (formerly Hawaiian Tug & Barge Corp.). When used in Hawaiian Electric Company, Inc. sections, the Company refers to Hawaiian Electric Company, Inc. and its direct subsidiaries.
Consumer Advocate	Division of Consumer Advocacy, Department of Commerce and Consumer Affairs of the State of Hawaii
DBEDT	State of Hawaii Department of Business, Economic Development and Tourism
DBF	State of Hawaii Department of Budget and Finance
D&O	Decision and order
DG	Distributed generation
DOD	Department of Defense federal
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOE	Department of Energy federal
DOH	Department of Health of the State of Hawaii
DRIP	HEI Dividend Reinvestment and Stock Purchase Plan
DSM	Demand-side management
ECAC	Energy cost adjustment clauses
EIP	2010 Equity and Incentive Plan
Energy Agreement	Agreement dated October 20, 2008 and signed by the Governor of the State of Hawaii, the State of Hawaii Department of Business, Economic Development and Tourism, the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and HECO, for itself and on behalf of its electric utility subsidiaries committing to actions to develop renewable energy and reduce dependence on fossil fuels in support of the HCEI
EPA	Environmental Protection Agency federal

EPS	Earnings per share
Exchange Act	Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation
federal	U.S. Government
FHLB	Federal Home Loan Bank
FHLMC	Federal Home Loan Mortgage Corporation
FNMA	Federal National Mortgage Association
FSS	Forward Starting Swaps

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GLOSSARY OF TERMS, continued

Terms	Definitions
GAAP	U.S. generally accepted accounting principles
GHG	Greenhouse gas
GNMA	Government National Mortgage Association
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric Company, Inc., an electric utility subsidiary of Hawaiian Electric Industries, Inc. and parent company of Hawaii Electric Light Company, Inc., Maui Electric Company, Limited, HECO Capital Trust III (unconsolidated subsidiary), Renewable Hawaii, Inc. and Uluwehiokama Biofuels Corp.
HEI	Hawaiian Electric Industries, Inc., direct parent company of Hawaiian Electric Company, Inc., American Savings Holdings, Inc., Pacific Energy Conservation Services, Inc., HEI Properties, Inc., HEI Investments, Inc. (dissolved in 2008), Hawaiian Electric Industries Capital Trust II, Hawaiian Electric Industries Capital Trust III and The Old Oahu Tug Service, Inc. (formerly Hawaiian Tug & Barge Corp.).
HEIII	HEI Investments, Inc. (dissolved in 2008), a wholly owned subsidiary of Hawaiian Electric Industries, Inc.
HEIRSP	Hawaiian Electric Industries Retirement Savings Plan
HELCO	Hawaii Electric Light Company, Inc., an electric utility subsidiary of Hawaiian Electric Company, Inc.
HPOWER	City and County of Honolulu with respect to a power purchase agreement for a refuse-fired plant
IPP	Independent power producer
IRP	Integrated resource plan
Kalaeloa	Kalaeloa Partners, L.P.
kV	Kilovolt
kW	Kilowatt
KWH	Kilowatthour
MECO	Maui Electric Company, Limited, an electric utility subsidiary of Hawaiian Electric Company, Inc.
MW	Megawatt/s (as applicable)
MWh	Megawatthour
NII	Net interest income
NPV	Net portfolio value
NQSO	Nonqualified stock option
O&M	Operation and maintenance
OPEB	Postretirement benefits other than pensions
OTS	Office of Thrift Supervision, Department of Treasury
OTTI	Other than temporary impairment
PBF	Public benefits fund
PPA	Power purchase agreement
PRPs	Potentially responsible parties
PUC	Public Utilities Commission of the State of Hawaii
RAM	Revenue adjustment mechanism
RBA	Revenue balancing account
REG	Renewable Energy Group Marketing and Logistics, LLC
RFP	Request for proposal
RHI	Renewable Hawaii, Inc., a wholly owned subsidiary of Hawaiian Electric Company, Inc.
ROACE	Return on average common equity
ROR	Return on average rate base
RPS	Renewable portfolio standards
SAR	Stock appreciation right
SEC	Securities and Exchange Commission
See	Means the referenced material is incorporated by reference
SOIP	1987 Stock Option and Incentive Plan, as amended
SPRBs	Special Purpose Revenue Bonds
TOOTS	The Old Oahu Tug Service, a wholly owned subsidiary of Hawaiian Electric Industries, Inc.

UBC	Uluwehiokama Biofuels Corp., a non-regulated subsidiary of Hawaiian Electric Company, Inc.
VIE	Variable interest entity

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FORWARD-LOOKING STATEMENTS

This report and other presentations made by Hawaiian Electric Industries, Inc. (HEI) and Hawaiian Electric Company, Inc. (HECO) and their subsidiaries contain forward-looking statements, which include statements that are predictive in nature, depend upon or refer to future events or conditions, and usually include words such as expects, anticipates, intends, plans, believes, predicts, estimates or similar expressions. I addition, any statements concerning future financial performance, ongoing business strategies or prospects or 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:

- international, national and local economic conditions, including the state of the Hawaii tourism and construction industries, the strength or weakness of the Hawaii and continental U.S. real estate markets (including the fair value and/or the actual performance of collateral underlying loans held by American Savings Bank, F.S.B. (ASB), which could result in higher loan loss provisions and write-offs), decisions concerning the extent of the presence of the federal government and military in Hawaii, and the implications and potential impacts of current capital and credit market conditions and federal and state responses to those conditions;

- weather and natural disasters, such as hurricanes, earthquakes, tsunamis, lightning strikes and the potential effects of global warming (such as more severe storms and rising sea levels);

- global developments, including terrorist acts, the war on terrorism, continuing U.S. presence in Afghanistan, potential conflict or crisis with North Korea or in the Middle East and Iran s nuclear activities;

- the timing and extent of changes in interest rates and the shape of the yield curve;

- the ability of the Company to access credit markets to obtain commercial paper and other short-term and long-term debt financing (including lines of credit) and to access capital markets to issue HEI common stock under volatile and challenging market conditions, and the cost of such financings, if available;

- the risks inherent in changes in the value of pension and other retirement plan assets and securities available for sale;

- changes in laws, regulations, market conditions and other factors that result in changes in assumptions used to calculate retirement benefits costs and funding requirements;

- the impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) and of the rules and regulations that the Dodd-Frank Act requires to be promulgated over the next several months;

- 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 ASB s cost of funds);

- the implementation of the Energy Agreement with the State of Hawaii and Consumer Advocate (Energy Agreement) setting forth the goals and objectives of a Hawaii Clean Energy Initiative (HCEI), revenue decoupling and the fulfillment by the utilities of their commitments under the Energy Agreement (given the Public Utilities Commission of the State of Hawaii (PUC) approvals needed; the PUC s potential delay in considering HCEI-related costs; reliance by the Company on outside parties like the state, independent power producers (IPPs) and developers; potential changes in political support for the HCEI; and uncertainties surrounding wind power, the proposed undersea cable, biofuels, environmental assessments and the impacts of implementation of the HCEI on future costs of electricity);

- capacity and supply constraints or difficulties, especially if generating units (utility-owned or 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;

- the risk to generation reliability when generation peak reserve margins on Oahu are strained;

- fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses (ECACs);

- the impact of fuel price volatility on customer satisfaction and political and regulatory support for the utilities;

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- the risks associated with increasing reliance on renewable energy, as contemplated under the Energy Agreement, including the availability and cost of non-fossil fuel supplies for renewable generation and the operational impacts of adding intermittent sources of renewable energy to the electric grid;

- 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) or their competitors;

- federal, state, county and international governmental and regulatory actions, such as changes in laws, rules and regulations applicable to HEI, HECO, ASB and their subsidiaries (including changes in taxation, increases in capital requirements, regulatory changes resulting from the HCEI, environmental laws and regulations, the regulation of greenhouse gas emissions (GHG), healthcare reform, governmental fees and assessments (such as Federal Deposit Insurance Corporation assessments), potential carbon cap and trade legislation that may fundamentally alter costs to produce electricity and accelerate the move to renewable generation);

- decisions by the PUC in rate cases and other proceedings (including the risks of delays in the timing of decisions, adverse changes in final decisions from interim decisions and the disallowance of project costs);

- decisions by the PUC and by other agencies and courts on land use, environmental and other permitting issues (such as required corrective actions, restrictions and penalties that may arise, for example with respect to environmental conditions or renewable portfolio standards (RPS));

- enforcement actions by the OTS (or its regulatory successors, the Office of the Comptroller of the Currency and the Federal Reserve Board) and other governmental authorities (such as consent orders, required corrective actions, restrictions and penalties that may arise, for example, with respect to compliance deficiencies under existing or new banking and consumer protection laws and regulations or with respect to capital adequacy);

- increasing operation and maintenance expenses and investment in infrastructure for the electric utilities, resulting in the need for more frequent rate cases;

- the risks associated with the geographic concentration of HEI s businesses and ASB s loans, ASB s concentration in a single product type (first mortgages) and ASB s significant credit relationships (i.e., concentrations of large loans and/or credit lines with certain customers);

- changes in accounting principles applicable to HEI, HECO, ASB and their subsidiaries, including the adoption of International Financial Reporting Standards (IFRS) or new U.S. accounting standards, the potential discontinuance of regulatory accounting and the effects of potentially required consolidation of variable interest entities or required capital lease accounting for PPAs with IPPs;

- 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 assets 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 and charge-offs;

- changes in ASB s deposit cost or mix which may have an adverse impact on ASB s cost of funds;

- the final outcome of tax positions taken by HEI, HECO, ASB and their subsidiaries;

- the risks of suffering losses and incurring liabilities that are uninsured or underinsured; and

- other risks or uncertainties described elsewhere in this report and in other 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, HECO, ASB and their subsidiaries undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

(in thousands, except per share amounts)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Revenues				
Electric utility	$ 623,126	$ 548,440	$ 1,755,332	$ 1,460,654
Bank	71,429	71,947	213,975	229,478
Other	(14)	(74)	(62)	(121)
	694,541	**620,313**	**1,969,245**	**1,690,011**
Expenses				
Electric utility	571,783	494,268	1,619,945	1,343,250
Bank	47,040	54,258	142,040	189,162
Other	3,087	3,148	10,291	9,247
	621,910	**551,674**	**1,772,276**	**1,541,659**
Operating income (loss)				
Electric utility	51,343	54,172	135,387	117,404
Bank	24,389	17,689	71,935	40,316
Other	(3,101)	(3,222)	(10,353)	(9,368)
	72,631	**68,639**	**196,969**	**148,352**
Interest expense other than on deposit liabilities and other bank borrowings	(21,015)	(19,678)	(61,916)	(55,421)
Allowance for borrowed funds used during construction	492	1,118	2,061	4,467
Allowance for equity funds used during construction	1,197	2,628	4,817	10,353
Income before income taxes	**53,305**	**52,707**	**141,931**	**107,751**
Income taxes	20,385	18,753	51,677	36,977
Net income	**32,920**	**33,954**	**90,254**	**70,774**
Preferred stock dividends of subsidiaries	471	471	1,417	1,417
Net income for common stock	**$ 32,449**	**$ 33,483**	**$ 88,837**	**$ 69,357**
Basic earnings per common share	$ 0.35	$ 0.37	$ 0.95	$ 0.76
Diluted earnings per common share	$ 0.35	$ 0.37	$ 0.95	$ 0.76
Dividends per common share	$ 0.31	$ 0.31	$ 0.93	$ 0.93
Weighted-average number of common shares outstanding	93,699	91,522	93,148	91,173
Dilutive effect of share-based compensation	192	131	257	105
Adjusted weighted-average shares	93,891	91,653	93,405	91,278

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Balance Sheets (unaudited)

(dollars in thousands)	September 30, 2010	December 31, 2009
Assets		
Cash and cash equivalents	$ 387,488	$ 503,922
Accounts receivable and unbilled revenues, net	259,132	241,116
Available-for-sale investment and mortgage-related securities	570,262	432,881
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,466,550	3,670,493
Property, plant and equipment, net of accumulated depreciation of $2,011,138 and $1,945,482	3,131,198	3,088,611
Regulatory assets	422,177	426,862
Other	478,406	381,163
Goodwill, net	82,190	82,190
Total assets	$ 8,895,167	$ 8,925,002
Liabilities and stockholders equity		
Liabilities		
Accounts payable	$ 142,971	$ 159,044
Interest and dividends payable	31,318	27,950
Deposit liabilities	3,958,636	4,058,760
Short-term borrowings other than bank	27,296	41,989
Other bank borrowings	246,571	297,628
Long-term debt, net other than bank	1,364,911	1,364,815
Deferred income taxes	253,284	188,875
Regulatory liabilities	289,568	288,214
Contributions in aid of construction	331,405	321,544
Other	735,261	700,242
Total liabilities	7,381,221	7,449,061
Preferred stock of subsidiaries - not subject to mandatory redemption	34,293	34,293
Stockholders equity		
Preferred stock, no par value, authorized 10,000,000 shares; issued: none		
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding: 94,121,108 shares and 92,520,638 shares	1,301,710	1,265,157
Retained earnings	186,425	184,213
Accumulated other comprehensive loss, net of tax benefits	(8,482)	(7,722)
Total stockholders equity	1,479,653	1,441,648
Total liabilities and stockholders equity	$ 8,895,167	$ 8,925,002

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity (unaudited)

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other comprehensive loss	Total
Balance, December 31, 2009	**92,521**	**$ 1,265,157**	**$ 184,213**	**$ (7,722)**	**$ 1,441,648**
Comprehensive income (loss):					
Net income for common stock			88,837		88,837
Net unrealized gains on securities:					
Net unrealized gains on securities arising during the period, net of taxes of $1,599				2,421	2,421
Unrealized losses on derivatives qualified as cash flow hedges:					
Net unrealized holding losses arising during the period, net of tax benefits of $2,278				(3,575)	(3,575)
Retirement benefit plans:					
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,932				3,034	3,034
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,681				(2,640)	(2,640)
Comprehensive income			88,837	(760)	88,077
Issuance of common stock, net	1,600	36,553			36,553
Common stock dividends ($0.93 per share)			(86,625)		(86,625)
Balance, September 30, 2010	**94,121**	**$ 1,301,710**	**$ 186,425**	**$ (8,482)**	**$ 1,479,653**
Balance, December 31, 2008	**90,516**	**$ 1,231,629**	**$ 210,840**	**$ (53,015)**	**$ 1,389,454**
Cumulative effect of adoption of a standard on other-than- temporary impairment recognition, net of taxes of $2,497			3,781	(3,781)	
Comprehensive income (loss):					
Net income for common stock			69,357		69,357
Net unrealized gains (losses) on securities:					
Net unrealized gains on securities arising during the period, net of taxes of $16,248				24,607	24,607
Net unrealized losses related to factors other than credit during the period, net of tax benefits of $6,650				(10,072)	(10,072)
Less: reclassification adjustment for net realized losses included in net income, net of tax benefits of $6,125				9,276	9,276
Retirement benefit plans:					
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $5,562				8,717	8,717
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $4,990				(7,835)	(7,835)
Comprehensive income			69,357	24,693	94,050
Issuance of common stock, net	1,499	23,264			23,264
Common stock dividends ($0.93 per share)			(84,860)		(84,860)

Balance, September 30, 2009	**92,015**	**$**	**1,254,893**	**$**	**199,118**	**$**	**(32,103)**	**$** **1,421,908**

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Cash Flows (unaudited)

Nine months ended September 30 (in thousands)	**2010**	**2009**
Cash flows from operating activities		
Net income	$ 90,254	$ 70,774
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	117,109	113,916
Other amortization	2,995	4,037
Provision for loan losses	12,310	27,000
Loans receivable originated and purchased, held for sale	(286,950)	(368,880)
Proceeds from sale of loans receivable, held for sale	306,587	400,213
Net gain on sale of investment and mortgage-related securities		(44)
Other-than-temporary impairment of available-for-sale mortgage-related securities		15,444
Changes in deferred income taxes	75,821	2,958
Changes in excess tax benefits from share-based payment arrangements	56	324
Allowance for equity funds used during construction	(4,817)	(10,353)
Increase in cash overdraft	884	
Changes in assets and liabilities		
Decrease (increase) in accounts receivable and unbilled revenues, net	(18,016)	48,480
Decrease (increase) in fuel oil stock	(42,569)	9,826
Decrease in accounts, interest and dividends payable	(12,705)	(641)
Changes in prepaid and accrued income taxes and utility revenue taxes	(45,787)	(50,514)
Changes in other assets and liabilities	(5,585)	(35,561)
Net cash provided by operating activities	**189,587**	**226,979**
Cash flows from investing activities		
Available-for-sale investment and mortgage-related securities purchased	(485,495)	(247,425)
Principal repayments on available-for-sale investment and mortgage-related securities	350,673	304,728
Proceeds from sale of available-for-sale investment and mortgage-related securities		44
Net decrease in loans held for investment	171,242	396,706
Proceeds from sale of real estate acquired in settlement of loans	3,405	
Capital expenditures	(137,628)	(239,441)
Contributions in aid of construction	16,775	7,472
Other	1,615	426
Net cash provided by (used in) investing activities	**(79,413)**	**222,510**
Cash flows from financing activities		
Net decrease in deposit liabilities	(100,124)	(132,234)
Net decrease in short-term borrowings with original maturities of three months or less	(14,693)	
Net decrease in retail repurchase agreements	(51,057)	(18,573)
Proceeds from other bank borrowings		310,000
Repayments of other bank borrowings		(604,517)
Proceeds from issuance of long-term debt		153,186
Changes in excess tax benefits from share-based payment arrangements	(56)	(324)
Net proceeds from issuance of common stock	16,672	11,004
Common stock dividends	(69,585)	(73,931)
Preferred stock dividends of subsidiaries	(1,417)	(1,417)
Decrease in cash overdraft		(9,847)
Other	(6,348)	(7,232)
Net cash used in financing activities	**(226,608)**	**(373,885)**
Net increase (decrease) in cash and cash equivalents	(116,434)	75,604
Cash and cash equivalents, beginning of period	503,922	183,435

Cash and cash equivalents, end of period	**$**	**387,488**	**$**	**259,039**

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1 • Basis of presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles (GAAP) for interim financial information, the instructions to SEC Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. In preparing the financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenues and expenses for the period. Actual results could differ significantly from those estimates. The accompanying unaudited consolidated financial statements and the following notes should be read in conjunction with the audited consolidated financial statements and the notes thereto incorporated by reference in HEI s Form 10-K for the year ended December 31, 2009 and the unaudited consolidated financial statements and the notes thereto in HEI s Quarterly Reports on SEC Form 10-Q for the quarters ended March 31, 2010 and June 30, 2010.

In the opinion of HEI s management, the accompanying unaudited consolidated financial statements contain all material adjustments required by GAAP to fairly state the Company s financial position as of September 30, 2010 and December 31, 2009, the results of its operations for the three and nine months ended September 30, 2010 and 2009 and cash flows for the nine months ended September 30, 2010 and 2009. All such adjustments are of a normal recurring nature, unless otherwise disclosed in this Form 10-Q or other referenced material. Results of operations for interim periods are not necessarily indicative of results for the full year. When required, certain reclassifications are made to the prior period s consolidated financial statements to conform to the current presentation.

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2 • Segment financial information

(in thousands)	Electric Utility	Bank	Other	Total
Three months ended September 30, 2010				
Revenues from external customers	$ 623,090	71,429	22	$ 694,541
Intersegment revenues (eliminations)	36		(36)	
Revenues	623,126	71,429	(14)	694,541
Income (loss) before income taxes	37,197	24,359	(8,251)	53,305
Income taxes (benefit)	14,719	9,066	(3,400)	20,385
Net income (loss)	22,478	15,293	(4,851)	32,920
Preferred stock dividends of subsidiaries	498		(27)	471
Net income (loss) for common stock	21,980	15,293	(4,824)	32,449
Nine months ended September 30, 2010				
Revenues from external customers	$ 1,755,213	213,975	57	$ 1,969,245
Intersegment revenues (eliminations)	119		(119)	
Revenues	1,755,332	213,975	(62)	1,969,245
Income (loss) before income taxes	95,063	71,842	(24,974)	141,931
Income taxes (benefit)	35,893	26,682	(10,898)	51,677
Net income (loss)	59,170	45,160	(14,076)	90,254
Preferred stock dividends of subsidiaries	1,496		(79)	1,417
Net income (loss) for common stock	57,674	45,160	(13,997)	88,837
Assets (at September 30, 2010)	4,089,328	4,804,155	1,684	8,895,167
Three months ended September 30, 2009				
Revenues from external customers	$ 548,373	$ 71,947	$ (7)	$ 620,313
Intersegment revenues (eliminations)	67		(67)	
Revenues	548,440	71,947	(74)	620,313
Income (loss) before income taxes	42,877	17,665	(7,835)	52,707
Income taxes (benefit)	15,865	6,342	(3,454)	18,753
Net income (loss)	27,012	11,323	(4,381)	33,954
Preferred stock dividends of subsidiaries	498		(27)	471
Net income (loss) for common stock	26,514	11,323	(4,354)	33,483
Nine months ended September 30, 2009				
Revenues from external customers	1,460,515	229,478	18	1,690,011
Intersegment revenues (eliminations)	139		(139)	
Revenues	1,460,654	229,478	(121)	1,690,011
Income (loss) before income taxes	90,626	40,239	(23,114)	107,751
Income taxes (benefit)	32,989	14,013	(10,025)	36,977
Net income (loss)	57,637	26,226	(13,089)	70,774
Preferred stock dividends of subsidiaries	1,496		(79)	1,417
Net income (loss) for common stock	56,141	26,226	(13,010)	69,357
Assets (at December 31, 2009)	3,978,392	4,940,985	5,625	8,925,002

Intercompany electric sales of consolidated HECO 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.

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3 • Electric utility subsidiary

For HECO s consolidated financial information, including its commitments and contingencies, see pages 21 through 43.

4 • Bank subsidiary

Selected financial information

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

Consolidated Statements of Income Data (unaudited)

	Three months ended September 30		Nine months ended September 30	
(in thousands)	**2010**	**2009**	**2010**	**2009**
Interest and dividend income				
Interest and fees on loans	$ 49,221	$ 53,080	$ 148,294	$ 166,535
Interest and dividends on investment and mortgage-related securities	3,852	6,943	10,815	21,762
	53,073	60,023	159,109	188,297
Interest expense				
Interest on deposit liabilities	3,390	7,286	11,665	28,753
Interest on other borrowings	1,414	2,205	4,258	7,710
	4,804	9,491	15,923	36,463
Net interest income	**48,269**	**50,532**	**143,186**	**151,834**
Provision for loan losses	5,961	5,200	12,310	27,000
Net interest income after provision for loan losses	**42,308**	**45,332**	**130,876**	**124,834**
Noninterest income				
Fee income on deposit liabilities	6,109	8,211	21,520	22,384
Fees from other financial services	6,781	6,385	19,844	18,747
Fee income on other financial products	1,697	1,613	4,957	4,285
Net losses on available-for-sale securities		(9,863)		(15,400)
Other income	3,769	5,578	8,545	11,165
	18,356	11,924	54,866	41,181
Noninterest expense				
Compensation and employee benefits	18,168	17,721	54,477	55,072
Occupancy	4,176	4,905	12,617	15,956
Data processing	2,019	3,684	10,921	10,352
Services	1,544	2,437	5,117	9,656
Equipment	1,600	1,782	4,949	7,112
Loss on early extinguishment of debt				101
Other expense	8,798	9,062	25,819	27,527
	36,305	39,591	113,900	125,776
Income before income taxes	**24,359**	**17,665**	**71,842**	**40,239**
Income taxes	9,066	6,342	26,682	14,013
Net income	**$ 15,293**	**$ 11,323**	**45,160**	**$ 26,226**

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

Consolidated Balance Sheets Data (unaudited)

(in thousands)	September 30, 2010	December 31, 2009
Assets		
Cash and cash equivalents	$ 350,404	$ 425,896
Federal funds sold	1,000	1,479
Available-for-sale investment and mortgage-related securities	570,262	432,881
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,466,550	3,670,493
Other	235,985	230,282
Goodwill, net	82,190	82,190
	$ 4,804,155	$ 4,940,985
Liabilities and stockholder s equity		
Deposit liabilities noninterest-bearing	$ 830,593	$ 808,474
Deposit liabilities interest-bearing	3,128,043	3,250,286
Other borrowings	246,571	297,628
Other	96,306	92,129
	4,301,513	4,448,517
Common stock	330,493	329,439
Retained earnings	174,815	172,655
Accumulated other comprehensive loss, net of tax benefits	(2,666)	(9,626)
	502,642	492,468
	$ 4,804,155	$ 4,940,985

Other assets

(in thousands)	September 30, 2010	December 31, 2009
Bank-owned life insurance	$ 116,422	$ 113,433
Premises and equipment, net	56,534	54,428
Prepaid expenses	21,127	24,353
Accrued interest receivable	14,825	15,247
Mortgage-servicing rights	6,031	4,200
Real estate acquired in settlement of loans, net	4,474	3,959
Other	16,572	14,662
	$ 235,985	$ 230,282

Other liabilities

(in thousands)	September 30, 2010	December 31, 2009
Accrued expenses	$ 18,634	$ 17,270
Federal and state income taxes payable	30,207	19,141
Cashier s checks	24,656	26,877

Advance payments by borrowers		6,052		10,989
Other		16,757		17,852
	$	96,306	$	92,129

Other borrowings consisted of securities sold under agreements to repurchase and advances from the Federal Home Loan Bank (FHLB) of Seattle of $182 million and $65 million, respectively, as of September 30, 2010 and $233 million and $65 million, respectively, as of December 31, 2009.

Bank-owned life insurance is life insurance purchased by ASB on the lives of certain employees, with ASB as the beneficiary. The insurance is used to fund employee benefits through tax-free income from increases in the cash value of the policies and insurance proceeds paid to ASB upon an insured s death.

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As of September 30, 2010, ASB had total commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.2 billion.

Investment and mortgage-related securities portfolio.

Available-for-sale securities. The book value and aggregate fair value by major security type were as follows:

	September 30, 2010				December 31, 2009			
(in thousands)	**Book value**	**Gross unrealized gains**	**Gross unrealized losses**	**Estimated fair value**	**Book value**	**Gross unrealized gains**	**Gross unrealized losses**	**Estimated fair value**
Investment securities federal agency obligations	$ 265,941	$ 583	$ (49)	$ 266,475	$ 104,091	$ 109	$ (156)	$ 104,044
Mortgage-related securities FNMA, FHLMC and GNMA	265,449	10,935	(54)	276,330	319,642	7,967	(88)	327,521
Municipal bonds	27,003	510	(56)	27,457	1,300	16		1,316
	$ 558,393	$ 12,028	$ (159)	$ 570,262	$ 425,033	$ 8,092	$ (244)	$ 432,881

The following tables detail the contractual maturities and yields of available-for-sale securities. All positions with variable maturities (e.g., callable debentures and mortgage backed securities) are disclosed based upon the bond s contractual maturity. Actual average maturities may be substantially shorter than those detailed below.

			Maturity<1 year		Maturity 1-5 years		Maturity 5-10 years		Maturity>10 years	
(dollars in thousands)	**Book value**	**Weighted average yield (%)**	**Book value**	**Yield (%)**	**Book value**	**Yield (%)**	**Book value**	**Yield (%)**	**Book value**	**Yield (%)**
September 30, 2010										
Investment securities federal agency obligations	$ 265,941	1.32	$ 10,000	0.26	$ 215,408	1.18	$ 40,533	2.32	$	
Mortgage-related securities FNMA, FHLMC and GNMA	265,449	3.81			3,565	2.29	110,794	3.79	151,090	3.86
Municipal bonds	27,003	3.99	500	1.92	800	2.50	25,703	4.08		
	$ 558,393	2.63	$ 10,500	0.34	$ 219,773	1.20	$ 177,030	3.49	$ 151,090	3.86
December 31, 2009										
Investment securities federal agency obligations	$ 104,091	1.08	$		$ 94,091	1.01	$ 10,000	1.80	$	
Mortgage-related securities FNMA, FHLMC and GNMA	319,642	3.85			5,787	2.32	138,617	3.80	175,238	3.94
Municipal bonds	1,300	2.27	500	1.92	800	2.50				
	$ 425,033	3.17	$ 500	1.92	$ 100,678	1.10	$ 148,617	3.67	$ 175,238	3.94

The net losses on available for sale securities for the third quarter of 2009 of $9.9 million consisted of $13.7 million of total other-than-temporary impairment losses, net of $3.8 million of non-credit losses recognized in other comprehensive income.

The net losses on available for sale securities for the nine months ended September 30, 2009 of $15.4 million included impairment losses of $15.4 million, which consisted of $32.1 million of total other-than- temporary impairment losses, net of $16.7 million of non-credit losses recognized in other comprehensive income.

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Gross unrealized losses and fair value. The gross unrealized losses and fair values (for securities held in available for sale by duration of time in which positions have been held in a continuous loss position) were as follows:

	Less than 12 months		12 months or more		Total	
(in thousands)	**Gross unrealized losses**	**Fair value**	**Gross unrealized losses**	**Fair value**	**Gross unrealized losses**	**Fair value**
September 30, 2010						
Investment securities federal agency obligations	$ (49)	$ 39,966	$	$	$ (49)	$ 39,966
Mortgage-related securities FNMA, FHLMC and GNMA	(54)	5,357			(54)	5,357
Municipal bonds	(56)	3,600			(56)	3,600
	$ (159)	$ 48,923	$	$	$ (159)	$ 48,923
December 31, 2009						
Investment securities federal agency obligations	$ (156)	$ 54,834	$	$	$ (156)	$ 54,834
Mortgage-related securities FNMA, FHLMC and GNMA	(88)	15,352			(88)	15,352
Municipal bonds						
	$ (244)	$ 70,186	$	$	$ (244)	$ 70,186

The unrealized losses on ASB s investments in obligations issued by federal agencies were caused by interest rate movements. The contractual terms of these investments do not permit the issuer to settle the securities at a price less than the amortized cost bases of the investments.

Because ASB does not intend to sell the securities and has determined it is more likely than not that it will not be required to sell the investments before recovery of their amortized costs bases, which may be at maturity, ASB does not consider these investments to be other-than-temporarily impaired at September 30, 2010.

The fair values of ASB s investment securities could decline ifnterest rates rise or spreads widen.

Federal Deposit Insurance Corporation restoration plan. Under the Federal Deposit Insurance Reform Act of 2005 (the Reform Act), the Federal Deposit Insurance Corporation (FDIC) may set the designated reserve ratio within a range of 1.15% to 1.50%. The Reform Act requires that the FDIC s Board of Directors adopt a restoration plan when the Deposit Insurance Fund (DIF) reserve ratio falls below 1.15% or is expected to within six months. Financial institution failures have significantly increased the DIF s loss provisions, resulting in declines in the reserve ratio.

In May 2009, the board of directors of the FDIC voted to levy a special assessment on deposit institutions to build the DIF and restore public confidence in the banking system. ASB s special assessment was $2.3 million and ASB recorded the charge in June 2009.

In November 2009, the Board of Directors of the FDIC approved a restoration plan that required banks to prepay, by December 30, 2009, their estimated quarterly, risk-based assessments for the fourth quarter of 2009, and for all of 2010, 2011 and 2012. For the fourth quarter of 2009 and all of 2010, the prepaid assessment rate was assessed according to a risk-based premium schedule adopted earlier in 2009. The prepaid assessment rate for 2011 and 2012 was the current assessment rate plus 3 basis points. The prepaid assessment was recorded as a prepaid asset as of December 30, 2009, and each quarter thereafter ASB will record a charge to earnings for its regular quarterly assessment and offset the

prepaid expense until the asset is exhausted. Once the asset is exhausted, ASB will record an accrued expense payable each quarter for the assessment to be paid. If the prepaid assessment is not exhausted by December 30, 2014, any remaining amount will be returned to ASB. ASB s prepaid assessment was approximately $24 million. For each of the quarters ended September 30, 2010 and 2009, ASB s assessment rate was 14 basis points of deposits, or $1.4 million and $1.5 million, respectively.

The FDIC may impose additional special assessments in the future if it is deemed necessary to ensure the DIF ratio does not decline to a level that is close to zero or that could otherwise undermine public confidence in federal deposit insurance. Management cannot predict with certainty the timing or amounts of any additional assessments.

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Deposit insurance coverage. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act permanently raised the current standard maximum deposit insurance amount to $250,000. Previously, the standard maximum deposit insurance amount of $100,000 had been temporarily raised to $250,000 through December 31, 2013. The Dodd Frank Act also redefines the assessment base as average total consolidated assets less average tangible equity (previously the assessment base was based on deposits).

5 • Retirement benefits

Defined benefit plans. For the first nine months of 2010, the utilities contributed $23.8 million and HEI contributed $0.6 million to their respective retirement benefit plans, compared to $19.9 million and $1.0 million, respectively, in the first nine months of 2009. The Company s current estimate of contributions to its retirement benefit plans in 2010 is $32 million ($31 million to be made by the utilities and $1 million by HEI), compared to contributions of $25 million in 2009 ($24 million made by the utilities and $1 million by HEI). In addition, the Company expects to pay directly $2 million of benefits in 2010, compared to the $1 million paid in 2009.

The components of net periodic benefit cost were as follows:

	Three months ended September 30				Nine months ended September 30			
	Pension benefits		Other benefits		Pension benefits		Other benefits	
(in thousands)	2010	2009	2010	2009	2010	2009	2010	2009
Service cost	$ 7,376	$ 6,479	$ 1,248	$ 1,427	$ 21,424	$ 19,208	$ 3,539	$ 3,654
Interest cost	16,197	15,468	2,565	2,678	48,330	46,520	7,901	8,363
Expected return on plan assets	(17,272)	(14,336)	(2,792)	(2,240)	(51,687)	(42,907)	(8,310)	(6,677)
Amortization of unrecognized transition obligation	1	1		262	2	2		1,831
Amortization of prior service cost (credit)	(97)	(100)	(83)	(34)	(291)	(288)	(187)	(27)
Recognized actuarial loss (gain)	1,942	3,957	(5)	86	5,449	11,890	(8)	309
Net periodic benefit cost	8,147	11,469	933	2,179	23,227	34,425	2,935	7,453
Impact of PUC D&Os	2,574	(1,776)	1,512	(270)	7,602	(9,974)	4,133	(1,002)
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 10,721	$ 9,693	$ 2,445	$ 1,909	$ 30,829	$ 24,451	$ 7,068	$ 6,451

The Company recorded retirement benefits expense of $29 million and $24 million in the first nine months of 2010 and 2009, respectively, and charged the remaining amounts primarily to electric utility plant.

In the third quarter of 2010, MECO eliminated the electric discount benefit which will generate nominal credits through other benefit costs over the next few years as the total negative amendment credit is amortized.

Also, see Note 4, Retirement benefits, of HECO s Notes to Consolidated Financial Statements.

Defined contribution plan. For the first nine months of 2010 and 2009, ASB s total expense for its employees participating in the Hawaiian Electric Industries Retirement Savings Plan and the ASB 401(k) Plan combined was $2.9 million and $2.1 million, respectively. For the first nine months of 2010 and 2009, ASB s cash contributions were $3.2 million and $3.4 million, respectively.

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6 • Share-based compensation

The 2010 Equity and Incentive Plan (EIP) was approved by shareholders in May 2010 and allows HEI to issue an aggregate of 4 million shares of common stock as additional incentive compensation to selected employees in the form of stock options, stock appreciation rights, restricted shares, deferred shares, performance shares and other share-based and cash-based awards. Through September 30, 2010, grants under the EIP consisted of 77,500 deferred shares.

Under the 1987 Stock Option and Incentive Plan, as amended (SOIP), grants and awards of an estimated 1.1 million shares of common stock (based on various assumptions, including LTIP awards at maximum levels and the use of the September 30, 2010 market price of shares as the price on the exercise/payment dates) were outstanding as of September 30, 2010 to selected employees in the form of nonqualified stock options (NQSOs), stock appreciation rights (SARs), restricted stock units, LTIP performance and other shares and dividend equivalents. As of May 11, 2010, no new awards may be granted under the SOIP. After the shares of common stock for the outstanding SOIP grants and awards are issued or such grants and awards expire, the remaining registered shares under the SOIP will be deregistered and delisted.

For the NQSOs and SARs, the exercise price of each NQSO or SAR generally equaled the fair market value of HEI s stock on or near the date of grant. NQSOs, SARs and related dividend equivalents issued in the form of stock awarded generally became exercisable in installments of 25% each year for four years, and expire if not exercised ten years from the date of the grant. NQSOs and SARs compensation expense has been recognized in accordance with the fair value-based measurement method of accounting. The estimated fair value of each NQSO and SAR grant was calculated on the date of grant using a Binomial Option Pricing Model.

Restricted stock awards under the SOIP generally become unrestricted four years after the date of grant and are forfeited for terminations of employment during the vesting period, except that pro-rata vesting is provided for terminations by reason of death, disability or termination without cause. Restricted stock awards compensation expense has been recognized in accordance with the fair-value-based measurement method of accounting. Dividends on restricted stock awards are paid quarterly in cash.

Deferred shares and restricted stock units generally vest and will be issued as unrestricted stock four years after the date of the grant and are forfeited for terminations of employment during the vesting period, except that pro-rata vesting is provided for terminations due to death, disability and retirement. Deferred shares and restricted stock units expense has been recognized in accordance with the fair-value-based measurement method of accounting. Dividend equivalent rights are accrued quarterly and are paid in cash at the end of the restriction period when the deferred shares and restricted stock units vest.

Stock performance awards granted under the 2009-2011 and 2010-2012 Long-Term Incentive Plans (LTIP) entitle the grantee to shares of common stock with dividend equivalent rights once service conditions and performance conditions are satisfied at the end of the three-year performance period. LTIP awards are forfeited for terminations of employment during the performance period, except that pro-rata participation is provided for terminations due to death, disability and retirement based upon completed months of service after a minimum of 12 months of service in the performance period. Compensation expense for the stock performance awards portion of the LTIP has been recognized in accordance with the fair-value-based measurement method of accounting for performance shares.

The Company s share-based compensation expense and related income tax benefit are as follows:

($ in millions)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Share-based compensation expense (1)	0.6	0.3	2.0	0.7
Income tax benefit	0.2	0.1	0.6	0.2

(1) The Company has not capitalized any share-based compensation cost.

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Nonqualified stock options. Information about HEI s NQSOs is summarized as follows:

September 30, 2010	Outstanding & Exercisable (Vested)			
Year of grant	Range of exercise prices	Number of options	Weighted-average remaining contractual life	Weighted-average Exercise price
2001	$ 17.96	64,000	0.6	$ 17.96
2002	21.68	82,000	1.4	21.68
2003	20.49	117,500	2.2	20.49
	$ 17.96 21.68	263,500	1.6	$ 20.44

As of December 31, 2009, NQSOs outstanding totaled 374,500 (representing the same number of underlying shares), with a weighted-average exercise price of $19.73. As of September 30, 2010, all NQSOs outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $1.4 million.

NQSO activity and statistics are summarized as follows:

	Three months ended September 30		Nine months ended September 30	
($ in thousands, except prices)	2010	2009	2010	2009
Shares expired			2,000	1,000
Weighted-average price of shares expired			$ 20.49	$ 17.61
Shares exercised	46,000		109,000	
Weighted-average exercise price	$ 21.52		$ 18.48	
Cash received from exercise	$ 990		$ 2,014	
Intrinsic value of shares exercised (1)	$ 287		$ 912	
Tax benefit realized for the deduction of exercises	$ 81		$ 324	

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

Stock appreciation rights. Information about HEI s SARs is summarized as follows:

September 30, 2010	Outstanding & Exercisable (Vested)			
Year of grant	Range of exercise prices	Number of shares underlying SARs	Weighted-average remaining contractual life	Weighted-average exercise price
2004	$ 26.02	150,000	2.3	$ 26.02

2005			26.18	312,000	2.9	26.18
	$	26.02	26.18	462,000	2.7	$ 26.13

As of December 31, 2009, the shares underlying SARs outstanding totaled 480,000, with a weighted-average exercise price of $26.13. As of September 30, 2010, all SARs outstanding were exercisable and had no intrinsic value.

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SARs activity and statistics are summarized as follows:

($ in thousands, except prices)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Shares forfeited				6,000
Weighted-average price of shares forfeited				$ 26.18
Shares expired			18,000	305,000
Weighted-average price of shares expired			$ 26.18	$ 26.10
Shares vested				228,000
Aggregate fair value of vested shares				$ 1,354
Shares exercised				
Dividend equivalent shares distributed under Section 409A				3,143
Weighted-average Section 409A distribution price				$ 13.64
Intrinsic value of shares distributed under Section 409A(1)				$ 43
Tax benefit realized for Section 409A distributions				$ 17

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

Section 409A. As a result of the changes enacted in Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), for the nine months ended September 30, 2009 a total of 3,143 dividend equivalent shares for SAR grants were distributed to SOIP participants. Section 409A, which amended the federal income tax rules governing deferred compensation, required the Company to change the way certain affected dividend equivalents are paid in order to avoid significant adverse tax consequences to the SOIP participants. Generally, dividend equivalents subject to Section 409A will be paid within 2½ months after the end of the calendar year. Upon retirement, an SOIP participant may elect to take distributions of dividend equivalents subject to Section 409A at the time of retirement or at the end of the calendar year. The dividend equivalents associated with the 2005 SAR grants had no intrinsic value at December 31, 2009; thus, no distribution will be made in 2010. No further dividend equivalents are intended to be paid in accordance with this Section 409A modified distribution.

Restricted stock awards. Information about HEI s grants of restricted stock awards is summarized as follows:

	Three months ended September 30				Nine months ended September 30			
	2010		2009		2010		2009	
	Shares	(1)	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, beginning of period	78,700	$ 25.04	134,000	$ 25.50	129,000	$ 25.50	160,500	$ 25.51
Granted								
Vested and issued					(43,565)	26.29	(3,851)	24.52
Forfeited	(7,000)	23.00	(4,000)	25.36	(13,735)	24.35	(26,649)	25.68
Outstanding, end of period	71,700	$ 25.24	130,000	$ 25.50	71,700	$ 25.24	130,000	$ 25.50

(1) Represents the weighted-average grant-date fair value per share. The grant date fair value of a restricted stock award share was the closing or average price of HEI common stock on the date of grant.

For the nine months ended September 30, 2010 and 2009, total restricted stock vested had a fair value of $1.1 million and $94,000, respectively. The tax benefits realized for the tax deductions related to restricted stock awards were $0.1 million for each of the first nine months of 2010 and 2009.

As of September 30, 2010, there was $0.4 million of total unrecognized compensation cost related to nonvested restricted stock awards. The cost is expected to be recognized over a weighted-average period of 1.3 years.

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Deferred shares and restricted stock units. Information about HEI s grants of deferred shares and restricted stock units are summarized as follows:

	Three months ended September 30				Nine months ended September 30			
	2010		2009		2010		2009	
	Shares	(1)	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, beginning of period	146,500	$ 19.80	70,500	$ 16.99	70,500	$ 16.99		$
Granted					77,500(3)	22.30	70,500(2)	16.99
Vested and issued					(250)	16.99		
Forfeited					(1,250)	16.99		
Outstanding, end of period	146,500	$ 19.80	70,500	$ 16.99	146,500	$ 19.80	70,500	$ 16.99

(1) Represents the weighted-average grant-date fair value per share. The grant date fair value of the deferred shares and restricted stock units was the average price of HEI common stock on the date of grant.

(2) Total weighted-average grant-date fair value of $1.2 million.

(3) Total weighted-average grant-date fair value of $1.7 million

As of September 30, 2010, 77,500 deferred shares were outstanding under the EIP and 69,000 restricted stock units were outstanding under the SOIP.

For the nine months ended September 30, 2010, total restricted stock units vested had a fair value of $4,000 and related tax benefits to be realized will be immaterial.

As of September 30, 2010, there was $2.0 million of total unrecognized compensation cost related to the nonvested deferred shares and restricted stock units. The cost is expected to be recognized over a weighted-average period of 3.2 years.

LTIP payable in stock. The 2010-2012 LTIP and the 2009-2011 LTIP provide for payment in shares of HEI common stock based on the satisfaction of performance goals and service conditions over a three-year performance period. The number of shares of HEI common stock is fixed on the date the grants are made based on target performance levels. The payout varies from 0% to 200% of the number of target shares depending on achievement of the goals. The LTIP contains a market condition based on total return to shareholders (TRS) of HEI stock as a percentile to the Edison Electric Institute Index over the three-year period. The 2009-2011 LTIP performance condition is HEI return on average common equity (ROACE). The 2010-2012 LTIP goals with performance conditions include HEI consolidated net income, HECO consolidated ROACE, ASB net income and ASB return on assets all based on two-year averages (2011-2012).

LTIP linked to TRS. Information about HEI s LTIP grants linked to TRS is summarized as follows:

	Three months ended September 30				Nine months ended September 30			
	2010		2009		2010		2009	
	Shares	(1)	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, beginning of period	132,588	$ 20.42	36,198	$ 14.85	36,198	$ 14.85		$
Granted					97,191	22.45	36,198(2)	14.85
Vested and issued								
Forfeited	(5,806)	$ 22.45			(6,607)	21.53		
Outstanding, end of period	126,782	$ 20.33	36,198	$ 14.85	126,782	$ 20.33	36,198	$ 14.85

(1) Weighted-average grant-date fair value per share determined using a Monte Carlo simulation model.

(2) Total weighted-average grant-date fair value of $0.5 million.

On February 8, 2010, LTIP grants (under the 2010-2012 LTIP) were made with the TRS condition payable with 97,191 shares of HEI common stock (based on the grant date price of $18.95 and target performance levels) with a weighted-average grant date fair value of $2.2 million based on the weighted-average grant date fair value per share of $22.45.

The grant date fair values were determined using a Monte Carlo simulation model utilizing actual information for the common shares of HEI and its peers for the period from the beginning of the performance period to the grant date and estimated future stock volatility and dividends of HEI and its peers over the remaining three-year

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performance period. The expected stock volatility assumptions for HEI and its peer group were based on the three-year historic stock volatility, and the annual dividend yield assumptions were based on dividend yields calculated on the basis of daily stock prices over the same three-year historical period. The following table summarizes the assumptions used to determine the fair value of the LTIP linked to TRS and the resulting fair value of LTIP granted:

	2010	2009
Risk-free interest rate	1.30%	1.30%
Expected life in years	3	3
Expected volatility	27.9%	23.7%
Dividend yield	6.55%	4.53%
Range of expected volatility for Peer Group	22.3% to 52.3%	20.8% to 46.9%
Grant date fair value (per share)	$ 22.45	$ 14.85

As of September 30, 2010, there was $1.7 million of total unrecognized compensation cost related to the nonvested shares linked to TRS. The cost is expected to be recognized over a weighted-average period of 2.0 years.

LTIP linked to other performance conditions. Information about HEI s LTIP grants linked to other performance conditions is summarized as follows:

	Three months ended September 30				Nine months ended September 30			
	2010		2009		2010		2009	
	Shares	(1)	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, beginning of period	184,535	$ 18.69	24,131	$ 16.99	24,131	$ 16.99		$
Granted					160,939	18.95	24,131(2)	16.99
Vested								
Forfeited	(23,225)	$ 18.95			(23,760)	18.90		
Outstanding, end of period	161,310	$ 18.66	24,131	$ 16.99	161,310	$ 18.66	24,131	$ 16.99

(1) Weighted-average grant-date fair value per share based on the average price of HEI common stock on the date of grant.

(2) Total weighted-average grant-date fair value of $0.4 million.

On February 8, 2010, LTIP grants (under the 2010-2012 LTIP) with performance conditions were made, payable in 160,939 shares of HEI common stock (based on the grant date price of $18.95 and target performance levels), with a weighted-average grant date fair value of $3.0 million based on the weighted-average grant date fair value per share of $18.95.

As of September 30, 2010, there was $2.6 million of total unrecognized compensation cost related to the nonvested shares linked to performance conditions other than TRS. The cost is expected to be recognized over a weighted-average period of 2.1 years.

7 • Interest rate swap agreements

In June 2010, HEI entered into multiple Forward Starting Swaps (FSS) with notional amounts totaling $125 million to hedge against interest rate fluctuations on a portion of the $150 million of medium-term notes expected to be issued by HEI in 2011, thereby enabling HEI to better forecast its future interest expense. The FSS terminate in January and June 2011 and entitle HEI to receive/(pay) the present value of the positive/(negative) difference between three-month LIBOR and a fixed rate at termination applied to the notional amount over a five-year period. The FSS are designated and accounted for as cash flow hedges and have a negative fair value of $6.2 million as of September 30, 2010 (recorded in Other liabilities on the consolidated balance sheet). Changes in fair value are recognized (1) in other comprehensive income to the extent that they are considered effective, and (2) in net income for any portion considered ineffective. The balance in accumulated other comprehensive income/(loss) (AOCI) at the dates of the anticipated medium-term note issuances will be accreted/amortized into interest expense over the lives of the new notes based on the effective interest method. For the third quarter of 2010, the ineffective portion of the change in fair value, or $0.4 million ($0.2 million, net of tax benefits), was recorded as a derivative loss in Interest expense other than on deposit liabilities and other bank borrowings and the effective portion, or $3.6 million, net of tax benefits, was recorded as a net loss in AOCI. Of the $3.6 million net loss in AOCI, a net $0.3 million is expected to be reclassified to earnings during the next 12 months.

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8 • Earnings per share (EPS)

For the three and nine months ended September 30, 2010, under the two-class method of computing basic and diluted EPS, distributed earnings were $0.31 and $0.93 per share, respectively, and undistributed earnings were $0.04 and $0.02 per share, respectively, for both unvested restricted stock awards and unrestricted common stock. For the three and nine months ended September 30, 2009, under the two-class method of computing basic and diluted EPS, distributed earnings were $0.31 and $0.93 per share, respectively, and undistributed earnings (loss) were $0.06 and $(0.17) per share, respectively, for both unvested restricted stock awards and unrestricted common stock.

As of September 30, 2010 and 2009, the antidilutive effects of SARs (462,000 shares of HEI common stock) and SARs and NQSOs (743,500 shares of HEI common stock), respectively, for which the exercise prices were greater than the closing market price of HEI s common stock were not included in the computation of diluted EPS.

9 • Commitments and contingencies

See Note 4, Bank subsidiary, above and Note 5, Commitments and contingencies, of HECO s Notes to Consolidated Financial Statements, below.

10 • Fair value measurements

Fair value estimates are based on the price that would be received to sell an asset, or paid upon the transfer of a liability, in an orderly transaction between market participants at the measurement date. The fair value estimates are generally determined based on assumptions that market participants would use in pricing the asset or liability and are based on market data obtained from independent sources. However, in certain cases, the Company uses its own assumptions about market participant assumptions based on the best information available in the circumstances. These valuations are estimates at a specific point in time, based on relevant market information, information about the financial instrument and judgments regarding future expected loss experience, economic conditions, risk characteristics of various financial instruments and other factors. 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 active trading market exists for a portion of the Company s financial instruments, fair value estimates cannot be determined with precision. Changes in the underlying assumptions used, including discount rates and estimates of future cash flows, 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.

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 cash equivalents and short term borrowings other than bank. The carrying amount approximated fair value because of the short maturity of these instruments.

Investment and mortgage-related securities. Fair value was based on observable inputs using market-based valuation techniques.

Loans receivable. For residential real estate loans, fair value is calculated by discounting estimated cash flows using discount rates based on current industry pricing for loans with similar contractual characteristics.

For other types of loans, fair value is estimated by discounting contractual cash flows using discount rates that reflect current industry pricing for loans with similar characteristics and remaining maturity. Where industry pricing is not available, discount rates are based on ASB s current pricing for loans with similar characteristics and remaining maturity.

The fair value of all loans was adjusted to reflect current assessments of loan collectibility.

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

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estimated by discounting the future cash flows using the rates currently offered for deposits of similar remaining maturities.

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

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

Forward Starting Swaps. Fair value was estimated by discounting the expected future cash flows of the swaps, using the contractual terms of the swaps, including the period to maturity, and observable market-based inputs, including forward interest rate curves. Fair value incorporates credit valuation adjustments to appropriately reflect nonperformance risk.

Off-balance sheet financial instruments. The fair value of loans serviced for others was calculated by discounting expected net income streams using discount rates that reflect industry pricing for similar assets. Expected net income streams are estimated based on industry assumptions regarding prepayment speeds and income and expenses associated with servicing residential mortgage loans for others. The fair value of commitments to originate loans was estimated based on the change in current primary market prices of new commitments. Since lines of credit can expire without being drawn and customers are under no obligation to utilize the lines, no fair value was assigned to unused lines of credit. The fair value of letters of credit was estimated based on the fees currently charged to enter into similar agreements, taking into account the remaining terms of the agreements. The 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:

	September 30, 2010		December 31, 2009	
(in thousands)	**Carrying or notional amount**	**Estimated fair value**	**Carrying or notional amount**	**Estimated fair value**
Financial assets				
Cash and cash equivalents	$ 387,488	$ 387,488	$ 503,922	$ 503,922
Available-for-sale investment and mortgage-related securities	570,262	570,262	432,881	432,881
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764	97,764	97,764
Loans receivable, net	3,466,550	3,603,254	3,670,493	3,760,954
Financial liabilities				
Deposit liabilities	3,958,636	3,967,738	4,058,760	4,063,888
Short-term borrowings other than bank	27,296	27,296	41,989	41,989
Other bank borrowings	246,571	265,565	297,628	307,154
Long-term debt, net other than bank	1,364,911	1,403,063	1,364,815	1,336,250
Forward Starting Swaps	6,223	6,223		
Off-balance sheet items				

HECO-obligated preferred securities of trust subsidiary	50,000	50,340	50,000	48,480

As of September 30, 2010 and December 31, 2009, loan commitments and unused lines and letters of credit issued by ASB had notional amounts of $1.2 billion and their estimated fair values on such dates were $0.5 million and $0.2 million, respectively. As of September 30, 2010 and December 31, 2009, loans serviced by ASB for others had notional amounts of $762.6 million and $577.5 million and the estimated fair value of the servicing rights for such loans was $7.8 million and $5.6 million, respectively.

Fair value measurements on a recurring basis. While securities held in ASB s investment portfolio trade in active markets, they do not trade on listed exchanges nor do the specific holdings trade in quoted markets by dealers or brokers. All holdings are valued using market-based approaches that are based on exit prices that are taken from identical or similar market transactions, even in situations where trading volume may be low when compared with prior periods as has been the case during the current market disruption. Inputs to these valuation techniques reflect the assumptions that consider credit and nonperformance risk that market participants would

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use in pricing the asset based on market data obtained from independent sources. Available-for-sale securities were comprised of federal agency obligations and mortgage-backed securities and municipal bonds.

Assets measured at fair value on a recurring basis were as follows:

(in thousands)	Quoted prices in active markets for identical assets (Level 1)	Fair value measurements using Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
September 30, 2010			
Available-for-sale securities			
Mortgage-related securities-FNMA, FHLMC and GNMA	$	$ 276,330	$
Investment securities-federal agency obligation		266,475	
Municipal bonds		27,457	
	$	$ 570,262	$
Forward Starting Swaps	$	$ (6,223)	$
December 31, 2009			
Available-for-sale securities			
Mortgage-related securities-FNMA, FHLMC and GNMA	$	$ 327,521	$
Investment securities-federal agency obligation		104,044	
Municipal bonds		1,316	
	$	$ 432,881	$

Fair value measurements on a nonrecurring basis. From time to time, the Company may be required to measure certain assets at fair value on a nonrecurring basis in accordance with U.S. GAAP. These adjustments to fair value usually result from the application of lower-of-cost-or-market accounting or write-downs of individual assets. As of December 31, 2009, there were no adjustments to fair value for assets measured at fair value on a nonrecurring basis in accordance with U.S. GAAP. In the second and third quarters of 2010, HECO s asset retirement obligation was adjusted (see Note 8, Fair value measurements of HECO Notes to Consolidated Financial Statements below).

11 • Cash flows

Supplemental disclosures of cash flow information. For the nine months ended September 30, 2010 and 2009, the Company paid interest (net of amounts capitalized and including bank interest) to non-affiliates amounting to $69 million and $75 million, respectively.

For the nine months ended September 30, 2010 and 2009, the Company paid income taxes amounting to $44 million and $14 million, respectively. The increase in income taxes paid was primarily due to higher operating income in 2010 and estimated tax payments made through September 2010 without the retroactive effect of 2010 bonus depreciation (which was enacted after the payment of September 2010 estimated taxes).

Supplemental disclosures of noncash activities. Noncash increases in common stock for director and officer compensatory plans of the Company were $2.9 million and $1.5 million for the nine months ended September 30, 2010 and 2009, respectively.

Under the HEI Dividend Reinvestment and Stock Purchase Plan (DRIP), common stock dividends reinvested by shareholders in HEI common stock in noncash transactions amounted to $17 million and $11 million for the first nine months of 2010 and 2009, respectively. HEI satisfied the requirements of the HEI DRIP and the HEIRSP (from April 16, 2009 through September 3, 2009) and the ASB 401(k) Plan (from May 7, 2009 through September 3, 2009) by acquiring for cash its common shares through open market purchases rather than by issuing additional shares. Effective September 4, 2009, HEI resumed satisfying the requirements of the HEI DRIP, HEIRSP and ASB 401(k) Plan through the issuance of additional shares of common stock.

Real estate acquired in settlement of loans in noncash transactions amounted to $4 million in each of the first nine months of 2010 and 2009.

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12 • Recent accounting pronouncements and interpretations

Variable interest entities. In June 2009, the Financial Accounting Standards Board (FASB) issued a standard that amends the guidance in ASC Topic 810 related to the consolidation of variable interest entities (VIEs). The standard eliminates exceptions to consolidating qualifying special-purpose entities (QSPEs), contains new criteria for determining the primary beneficiary, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. The Company adopted this standard in the first quarter of 2010 and the adoption did not impact the Company s or HECO s consolidated financial condition, results of operations or liquidity.

Allowance for Credit Losses. In July 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-20, Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses, which will require the Company to provide a greater level of disaggregated information about the credit quality of the Company s loans and leases and the Allowance for Loan and Lease Losses (the Allowance). This ASU will also require the Company to disclose additional information related to credit quality indicators, nonaccrual and past due information, and information related to impaired loans and loans modified in a troubled debt restructuring. The provisions of this ASU are effective for the Company s reporting period ending December 31, 2010. As this ASU amends only the disclosure requirements for loans and leases and the Allowance, the adoption will have no impact on the Company s consolidated statements of income and balance sheet.

13 • Credit agreement

Effective May 7, 2010, HEI entered into a revolving unsecured credit agreement establishing a line of credit facility of $125 million, with a letter of credit sub-facility, expiring on May 7, 2013, with a syndicate of eight financial institutions. Any draws on the facility bear interest at the Adjusted LIBO Rate plus 225 basis points or the greatest of (a) the Prime Rate, (b) the sum of the Federal Funds Rate plus 50 basis points and (c) the Adjusted LIBO Rate for a one month Interest Period plus 100 basis points per annum, as defined in the agreement. Annual fees on undrawn commitments are 40 basis points. The agreement contains provisions for revised pricing in the event of a ratings change. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have broad material adverse change clauses. However, the agreement does contain customary conditions which must be met in order to draw on it, including compliance with its covenants.

HEI s $125 million credit facility will be maintained to support the issuance of commercial paper, but also may be drawn to repay HEI s short-term and long-term indebtedness, to make investments in or loans to subsidiaries and for HEI s working capital and general corporate purposes. HEI s $100 million syndicated credit facility expiring March 31, 2011 was terminated concurrently with the effectiveness of this new syndicated credit facility.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

(in thousands)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Operating revenues	**$ 622,223**	**$ 546,502**	**$ 1,751,029**	**$ 1,453,623**
Operating expenses				
Fuel oil	235,534	186,719	662,608	463,893
Purchased power	147,880	134,447	404,175	364,120
Other operation	62,665	61,173	182,163	186,751
Maintenance	30,618	25,968	89,894	81,562
Depreciation	36,277	35,557	113,568	108,406
Taxes, other than income taxes	58,317	50,031	164,278	137,741
Income taxes	14,818	15,957	36,972	33,228
	586,109	509,852	1,653,658	1,375,701
Operating income	**36,114**	**36,650**	**97,371**	**77,922**
Other income				
Allowance for equity funds used during construction	1,197	2,628	4,817	10,353
Other, net	510	1,657	2,123	6,493
	1,707	4,285	6,940	16,846
Interest and other charges				
Interest on long-term debt	14,383	13,601	43,149	37,458
Amortization of net bond premium and expense	799	735	2,192	2,092
Other interest charges	653	705	1,861	2,048
Allowance for borrowed funds used during construction	(492)	(1,118)	(2,061)	(4,467)
	15,343	13,923	45,141	37,131
Net income	**22,478**	**27,012**	**59,170**	**57,637**
Preferred stock dividends of subsidiaries	228	228	686	686
Net income attributable to HECO	**22,250**	**26,784**	**58,484**	**56,951**
Preferred stock dividends of HECO	270	270	810	810
Net income for common stock	**$ 21,980**	**$ 26,514**	**$ 57,674**	**$ 56,141**

HEI owns all of the common stock of HECO. Therefore, per share data with respect to shares of common stock of HECO are not meaningful.

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Balance Sheets (unaudited)

(dollars in thousands, except par value)	September 30, 2010	December 31, 2009
Assets		
Utility plant, at cost		
Land	$ 51,371	$ 52,530
Plant and equipment	4,832,409	4,696,257
Less accumulated depreciation	(1,915,263)	(1,848,416)
Construction in progress	105,492	132,980
Net utility plant	3,074,009	3,033,351
Current assets		
Cash and cash equivalents	35,044	73,578
Customer accounts receivable, net	141,678	133,286
Accrued unbilled revenues, net	95,866	84,276
Other accounts receivable, net	6,841	8,449
Fuel oil stock, at average cost	121,230	78,661
Materials and supplies, at average cost	36,293	35,908
Prepayments and other	82,089	16,201
Total current assets	519,041	430,359
Other long-term assets		
Regulatory assets	422,177	426,862
Unamortized debt expense	14,435	14,288
Other	59,666	73,532
Total other long-term assets	496,278	514,682
	$ 4,089,328	$ 3,978,392
Capitalization and liabilities		
Capitalization		
Common stock ($6 2/3 par value, authorized 50,000,000 shares; outstanding 13,786,959 shares)	$ 91,931	$ 91,931
Premium on capital stock	385,650	385,659
Retained earnings	846,350	827,036
Accumulated other comprehensive income, net of income taxes	1,961	1,782
Common stock equity	1,325,892	1,306,408
Cumulative preferred stock not subject to mandatory redemption	34,293	34,293
Long-term debt, net	1,057,911	1,057,815
Total capitalization	2,418,096	2,398,516
Current liabilities		
Accounts payable	116,710	132,711
Interest and preferred dividends payable	22,461	21,223
Taxes accrued	150,352	156,092
Other	52,099	48,192
Total current liabilities	341,622	358,218
Deferred credits and other liabilities		
Deferred income taxes	244,455	180,603
Regulatory liabilities	289,568	288,214
Unamortized tax credits	58,083	56,870
Retirement benefits liability	293,069	296,623
Other	113,030	77,804
Total deferred credits and other liabilities	998,205	900,114
Contributions in aid of construction	331,405	321,544
	$ 4,089,328	$ 3,978,392

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Changes in Common Stock Equity (unaudited)

(in thousands)	Common stock Shares	Common stock Amount	Premium on capital stock	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance, December 31, 2009	**13,787**	**$ 91,931**	**$ 385,659**	**$ 827,036**	**$ 1,782**	**$ 1,306,408**
Comprehensive income (loss):						
Net income for common stock				57,674		57,674
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,796					2,819	2,819
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,681					(2,640)	(2,640)
Comprehensive income				57,674	179	57,853
Common stock dividends				(38,360)		(38,360)
Common stock issue expenses			(9)			(9)
Balance, September 30, 2010	**13,787**	**$ 91,931**	**$ 385,650**	**$ 846,350**	**$ 1,961**	**$ 1,325,892**
Balance, December 31, 2008	**12,806**	**$ 85,387**	**$ 299,214**	**$ 802,590**	**$ 1,651**	**$ 1,188,842**
Comprehensive income (loss):						
Net income for common stock				56,141		56,141
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $5,101					8,008	8,008
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $4,990					(7,835)	(7,835)
Comprehensive income				56,141	173	56,314
Common stock issue expenses			(7)			(7)
Common stock dividends				(32,756)		(32,756)
Balance, September 30, 2009	**12,806**	**$ 85,387**	**$ 299,207**	**$ 825,975**	**$ 1,824**	**$ 1,212,393**

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Cash Flows (unaudited)

Nine months ended September 30 (in thousands)	**2010**	**2009**
Cash flows from operating activities		
Net income	$ 59,170	$ 57,637
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	113,568	108,406
Other amortization	5,360	7,702
Changes in deferred income taxes	74,720	12,532
Changes in tax credits, net	1,939	(501)
Allowance for equity funds used during construction	(4,817)	(10,353)
Increase in cash overdraft	884	
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	(6,784)	32,423
Decrease (increase) in accrued unbilled revenues	(11,590)	14,183
Decrease (increase) in fuel oil stock	(42,569)	9,826
Increase in materials and supplies	(385)	(1,825)
Increase in regulatory assets	(3,269)	(13,829)
Decrease in accounts payable	(16,001)	(4,952)
Changes in prepaid and accrued income and utility revenue taxes	(55,202)	(62,388)
Changes in other assets and liabilities	1,415	3,360
Net cash provided by operating activities	**116,439**	**152,221**
Cash flows from investing activities		
Capital expenditures	(131,140)	(237,664)
Contributions in aid of construction	16,775	7,472
Other	657	340
Net cash used in investing activities	**(113,708)**	**(229,852)**
Cash flows from financing activities		
Common stock dividends	(38,360)	(32,756)
Preferred stock dividends of HECO and subsidiaries	(1,496)	(1,496)
Proceeds from issuance of long-term debt		153,186
Net decrease in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less		(30,850)
Decrease in cash overdraft		(9,847)
Other	(1,409)	(1,021)
Net cash provided by (used in) financing activities	**(41,265)**	**77,216**
Net decrease in cash and cash equivalents	(38,534)	(415)
Cash and cash equivalents, beginning of period	73,578	6,901
Cash and cash equivalents, end of period	**$ 35,044**	**$ 6,486**

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1 • Basis of presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with GAAP for interim financial information, the instructions to SEC Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. In preparing the financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenues and expenses for the period. Actual results could differ significantly from those estimates. The accompanying unaudited consolidated financial statements and the following notes should be read in conjunction with the audited consolidated financial statements and the notes thereto incorporated by reference in HECO s Form 10-K for the year ended December 31, 2009 and the unaudited consolidated financial statements and the notes thereto in HECO s Quarterly Reports on SEC Form 10-Q for the quarters ended March 31, 2010 and June 30, 2010.

In the opinion of HECO s management, the accompanying unaudited consolidated financial statements contain all material adjustments required by GAAP to fairly state the financial position of HECO and its subsidiaries as of September 30, 2010 and December 31, 2009 and the results of their operations for the three and nine months ended September 30, 2010 and 2009 and their cash flows for the nine months ended September 30, 2010 and 2009. All such adjustments are of a normal recurring nature, unless otherwise disclosed in this Form 10-Q or other referenced material. Results of operations for interim periods are not necessarily indicative of results for the full year. When required, certain reclassifications are made to the prior period s consolidated financial statements to conform to the current presentation.

2 • Unconsolidated variable interest entities

HECO Capital Trust III. 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 Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO) in the respective principal amounts of $10 million, (iii) making distributions on these 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 currently redeemable at the issuer s option without premium. The 2004 Debentures, together with the obligations of HECO, HELCO and MECO under an expense agreement and HECO s obligations under its trust guarantee and its guarantee of the obligations of HELCO and MECO under their respective debentures, are the sole assets of Trust III. Trust III has at all times been an unconsolidated subsidiary of HECO. Since HECO, as the common security holder, does not absorb the majority of the variability of Trust III, HECO is not the primary beneficiary and does not consolidate Trust III in accordance with accounting rules on the consolidation of VIEs. Trust III s balance sheets as of September 30, 2010 and December 31, 2009 each 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 statements for the nine months ended September 30, 2010 and 2009 each consisted of $2.5 million of interest income received from the 2004 Debentures, $2.4 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

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HECO will be subject to a number of restrictions, including a prohibition on the payment of dividends on its common stock.

Power purchase agreements (PPAs). As of September 30, 2010, HECO and its subsidiaries had six PPAs totaling 540 megawatts (MW) of firm capacity and other PPAs with smaller independent power producers (IPPs) and Schedule Q providers, none of which are currently required to be consolidated as VIEs. 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 the nine months ended September 30, 2010 totaled $404 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $106 million, $162 million, $43 million and $33 million, respectively.

Some of the IPPs have provided sufficient information for HECO to determine that the IPP was not a VIE, or was either a business or governmental organization (e.g., HPOWER), and thus excluded from the scope of accounting standards for VIEs. A windfarm and Kalaeloa provided sufficient information, as required under their PPAs or amendments, such that HECO could determine that consolidation was not required. Management has concluded that the consolidation of some IPPs is not required as HECO and its subsidiaries do not have variable interests in the IPPs because the PPAs do not require them to absorb any variability of the IPPs.

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 accounting standards for VIEs to that entity if the enterprise is unable to obtain the necessary information after making an exhaustive effort. HECO and its subsidiaries have made and continue to make exhaustive efforts to get the necessary information, but have been unsuccessful to date as it was not a contractual requirement prior to 2004. If the requested information is ultimately received from these IPPs, a possible outcome of future analyses is the consolidation of one or more of such IPPs. The consolidation of any significant IPP could have a material effect on the Company s and HECO s consolidated financial statements, including the recognition of a significant amount of assets and liabilities and the potential recognition of losses. If HECO and its subsidiaries determine they are required to consolidate the financial statements of such an IPP and the consolidation has a material effect, HECO and its subsidiaries would retrospectively apply accounting standards for VIEs.

3 • Revenue taxes

HECO and its subsidiaries operating revenues include amounts for various revenue taxes. Revenue taxes are generally recorded as an expense in the period the related revenues are recognized. However, HECO and its subsidiaries revenue tax payments to the taxing authorities are based on the prior year s revenues. For the nine months ended September 30, 2010 and 2009, HECO and its subsidiaries included approximately $156 million and $130 million, respectively, of revenue taxes in operating revenues and in taxes, other than income taxes expense.

4 • Retirement benefits

Defined benefit plans. For the first nine months of 2010, HECO and its subsidiaries contributed $23.8 million to their retirement benefit plans, compared to $19.9 million in the first nine months of 2009. HECO and its subsidiaries current estimate of contributions to their retirement benefit plans in 2010 is $31 million, compared to contributions of $24 million in 2009. In addition, HECO and its subsidiaries expect to pay directly $1.4 million of benefits in 2010, compared to $0.5 million paid in 2009.

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The components of net periodic benefit cost were as follows:

	Three months ended September 30				Nine months ended September 30			
	Pension benefits		Other benefits		Pension benefits		Other benefits	
(in thousands)	2010	2009	2010	2009	2010	2009	2010	2009
Service cost	$ 7,097	$ 6,205	$ 1,206	$ 1,385	$ 20,479	$ 18,372	$ 3,425	$ 3,549
Interest cost	14,816	14,005	2,500	2,594	44,053	42,089	7,667	8,114
Expected return on plan assets	(15,408)	(12,735)	(2,759)	(2,204)	(46,085)	(38,101)	(8,202)	(6,565)
Amortization of unrecognized transition obligation			(2)	259			(6)	1,824
Amortization of prior service cost (credit)	(186)	(190)	(86)	(37)	(560)	(558)	(197)	(37)
Recognized actuarial loss (gain)	1,925	3,677	(2)	79	5,377	11,021	2	296
Net periodic benefit cost	8,244	10,962	857	2,076	23,264	32,823	2,689	7,181
Impact of PUC D&Os	2,574	(1,776)	1,512	(270)	7,602	(9,974)	4,133	(1,002)
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 10,818	$ 9,186	$ 2,369	$ 1,806	$ 30,866	$ 22,849	$ 6,822	$ 6,179

HECO and its subsidiaries recorded retirement benefits expense of $29 million and $22 million for the first nine months of 2010 and 2009, respectively. The electric utilities charged a portion of the net periodic benefit cost to plant.

In the third quarter 2010, MECO eliminated the electric discount benefit which will generate nominal credits through other benefit costs over the next few years as the total negative amendment credit is amortized.

5 • Commitments and contingencies

Hawaii Clean Energy Initiative. In January 2008, the State of Hawaii (State) and the U.S. Department of Energy (DOE) signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative (HCEI). In October 2008, the Governor of the State, the State Department of Business, Economic Development and Tourism, the Division of Consumer Advocacy of the State Department of Commerce and Consumer Affairs, and HECO, on behalf of itself and its subsidiaries, HELCO and MECO (collectively, the parties), signed an Energy Agreement setting forth goals and objectives under the HCEI and the related commitments of the parties (the Energy Agreement), including pursuing a wide range of actions to decrease the State s dependence on imported fossil fuels through substantial increases in renewable energy and programs intended to secure greater energy efficiency and conservation. Many of the actions and programs included in the Energy Agreement require approval of the PUC.

Among the major provisions of the Energy Agreement are the following: (a) pursuing an overall goal of providing 70% of Hawaii s electricity and ground transportation energy needs from clean energy sources by 2030; (b) establishing a surcharge to recover costs stranded by clean energy initiatives and to expedite cost recovery for infrastructure that supports greater use of renewable energy or grid efficiency; (c) developing

a feed-in tariff (FIT) system with standardized purchase prices for renewable energy; (d) replacing system-wide caps on net energy metering (NEM) with per circuit thresholds that require a further study before a proposed interconnection that would take the circuit over the threshold may proceed; (e) adopting a regulatory rate-making model under which the utilities revenues would be decoupled from KWH sales; (f) continuing the existing energy cost adjustment clauses (ECACs), subject to periodic review by the PUC; (g) establishing a surcharge to allow the utilities to pass through all reasonably incurred purchased power costs; (h) supporting the development and use of renewable biofuels; (i) promoting greater use of renewable energy, including wind power and solar energy; (j) providing for the retirement or placement on reserve standby status of older and less efficient fossil fuel fired generating units as new, renewable generation is installed; (k) improving and expanding load management and demand response programs that allow the utilities to control customer loads to improve grid reliability and cost management; (l) the filing of PUC applications for approval of the installation of Advanced Metering Infrastructure, coupled with time-of-use or dynamic rate options for customers; (m) supporting prudent and cost effective investments in smart grid technologies; (n) delinking prices paid under all new renewable energy contracts from oil prices; and (o) exploring establishment of lifeline rates for low income customers.

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Many actions have been taken, and continue to be taken, to further the goals of the HCEI. In August 2010, the PUC issued a final decision and order (D&O) in the decoupling proceeding, which approved a proposed decoupling mechanism subject to certain modifications. In October 2010, the PUC approved the implementation of FITs for renewable energy generators, including applicable pricing, other terms and conditions and a standard form contract.

Renewable energy projects. HECO and its subsidiaries continue to negotiate with developers of proposed projects (identified in the Energy Agreement) to integrate into its grid approximately 1,100 MW from a variety of renewable energy sources, including solar, biomass, wind, ocean thermal energy conversion, wave and others. This includes HECO s commitment to integrate, with the assistance of the State, up to 400 MW of wind power into the Oahu electrical grid that would be imported via a yet-to-be-built undersea transmission cable system from wind farms proposed by developers to be built on the islands of Lanai and/or Molokai. The State and HECO have agreed to work together to ensure the supporting infrastructure needed is in place to reliably accommodate this large increment of wind power, including appropriate additional storage capacity investments and any required utility system connections or interfaces with the cable and the wind farm facilities. In December 2009, the PUC issued a D&O that allows HECO to defer the costs of studies for this large wind project for later review of prudence and reasonableness.

Interim increases. As of September 30, 2010, HECO and its subsidiaries had recognized $167 million of revenues with respect to interim orders ($162 million related to interim orders regarding general rate increase requests and $5 million related to interim orders regarding certain integrated resource planning costs). Revenue amounts recorded pursuant to interim orders are subject to refund, with interest, if they exceed amounts allowed in a final order.

Major projects. Many public utility projects require PUC approval and various permits from other governmental agencies. Difficulties in obtaining, or the inability to obtain, the necessary approvals or permits can result in significantly increased project costs or even cancellation of projects. Further, completion of projects is subject to various risks, such as problems or disputes with vendors. In the event a project does not proceed, or if it becomes probable the PUC will disallow cost recovery for all or part of a project, project costs may need to be written off in amounts that could result in significant reductions in HECO s consolidated net income. Significant projects whose costs have not yet been allowed in rate base by a final PUC order include HECO s Campbell Industrial Park combustion turbine No. 1 (CIP CT-1) and transmission line, HECO s East Oahu Transmission Project, HELCO s CT-4, CT-5 and ST-7 and HECO s Customer Information System (CIS).

Campbell Industrial Park combustion turbine No. 1 (CIP CT-1) and transmission line. HECO built a 110 MW simple cycle combustion turbine generating unit and added an additional 138 kilovolt (kV) transmission line to transmit power from generating units at CIP to the rest of the Oahu electric grid (collectively, the Project).

In a second interim D&O to HECO s 2009 test year rate case issued in February 2010, the PUC granted HECO an increase of $12.7 million in annual revenues to recover $163 million of the costs of the Project. As of September 30, 2010, HECO s cost estimate for the Project was $196 million (of which $194 million had been incurred, including $9 million of allowance for funds used during construction (AFUDC)). In its 2011 test year rate case, HECO is seeking to recover actual project costs in excess of the $163 million estimate included in its 2009 test year rate case. Management believes no adjustment to project costs is required as of September 30, 2010.

East Oahu Transmission Project (EOTP). HECO had planned a project to construct a partially underground transmission line to a major substation. However, in 2002, an application for a permit, which would have allowed construction in a route through conservation district lands, was denied. In October 2007, the PUC approved HECO s request to expend funds (then estimated at $56 million - $42 million for Phase 1 and

$14 million for Phase 2) for a revised EOTP using different routes requiring the construction of subtransmission lines, but stated that the issue of recovery of the EOTP costs would be determined in a subsequent rate case, after the project is installed and in service.

Phase 1 was placed in service on June 29, 2010 and is currently estimated to cost $58 million (as a result of higher costs and the project delays). In April 2010, HECO proposed a modification of Phase 2 that uses smart grid

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technology and is estimated to cost $10 million (total cost of $15 million less $5 million of funding through the Smart Grid Investment Grant Program of the American Recovery and Reinvestment Act of 2009). In October 2010, the PUC approved HECO s modification request for Phase 2, which is projected for completion in 2012.

As of September 30, 2010, the accumulated costs recorded for the EOTP amounted to $60 million ($58 million for Phase 1 and $2 million for Phase 2), including (i) $12 million of planning and permitting costs incurred prior to the 2002 denial of the permit, (ii) $24 million of planning, permitting and construction costs incurred after the denial of the permit and (iii) $24 million for AFUDC. Management believes no adjustment to project costs is required as of September 30, 2010.

HELCO generating units. In 1991, HELCO began planning to meet increased forecast demand for electricity. HELCO planned to install at its Keahole power plant two 20 MW combustion turbines (CT-4 and CT-5), followed by an 18 MW heat recovery steam generator (ST-7), at which time the units would be converted to a 56 MW (net) dual-train combined-cycle unit. In 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.

CT-4 and CT-5 became operational in mid-2004 and the costs of CT-4 and CT-5 (less a previously agreed to $12 million write-off) were included in HELCO s 2006 test year rate case interim and final rate increases.

On June 22, 2009, ST-7 was placed into service. As of September 30, 2010, HELCO s cost estimate for ST-7 was $92 million (of which $91 million had been incurred). HELCO is seeking to recover the costs of ST-7 in its 2010 test year rate case.

Management believes that no further adjustment to project costs is required at September 30, 2010.

Customer Information System (CIS) Project. In 2005, the PUC approved the utilities request to (i) expend the then-estimated $20 million for a new CIS, provided that no part of the project costs may be included in rate base until the project is in service and is used and useful for public utility purposes, and (ii) defer certain computer software development costs, accumulate AFUDC during the deferral period, amortize the deferred costs over a specified period and include the unamortized deferred costs in rate base, subject to specified conditions.

HECO signed a contract with a software company in March 2006 with a transition to the new CIS originally scheduled to occur in February 2008, which transition did not occur. HECO subsequently contracted with a new CIS software vendor and a new system integrator. The CIS Project is proceeding with the implementation of the new software system. As of September 30, 2010, the accumulated deferred and capital costs recorded for the CIS amounted to $16 million. Management believes no adjustment to project costs is required as of September 30, 2010.

Environmental regulation. HECO 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. In the

last year, legislative and regulatory activity related to the environment, including proposals and rulemaking under the Clean Air Act (CAA) and Clean Water Act, has increased significantly and management anticipates that such activity will continue. Depending upon the final outcome of the legislative and regulatory activity (including under the Clean Water Act with respect to cooling water intake controls and changes in effluent standards and the Clean Air Act with respect to hazardous air pollutant emissions, tightening of the National Ambient Air Quality Standards, and the Regional Haze rule), HECO and its subsidiaries may be required to incur material capital expenditures and other compliance costs.

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

Honolulu Harbor investigation. HECO has been involved since 1995 in a work group with several other potentially responsible parties (PRPs) identified by the State of Hawaii Department of Health (DOH), including oil companies, in investigating and responding to historical subsurface petroleum contamination in the Honolulu Harbor

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area. A subset of the PRPs (the Participating Parties) entered into a joint defense agreement and ultimately entered into an Enforceable Agreement with the DOH to address petroleum contamination at the site. The Participating Parties are funding the 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. Although the Honolulu Harbor investigation involves four units Iwilei, Downtown, Kapalama and Sand Island to date all the investigative and remedial work has focused on the Iwilei Unit.

The Participating Parties have conducted subsurface investigations, assessments and preliminary oil removal, and anticipate finalizing remedial design work for the Iwilei unit in 2010.

As of September 30, 2010, HECO s remaining accrual for its estimated share of environmental costs for the Iwilei unit was $1.4 million ($3.3 million expensed less $1.9 million expended). Because (1) the full scope of work remains to be determined, (2) the final cost allocation method among the Participating Parties has not yet been established and (3) management cannot estimate the costs to be incurred (if any) for the sites other than the Iwilei unit (such as its Honolulu power plant located in the Downtown unit), the cost estimate may be subject to significant change and additional material costs may be incurred.

Global climate change and greenhouse gas (GHG) emissions reduction. National and international concern about climate change and the contribution of GHG emissions to global warming have led to action by the State and to federal legislative and regulatory proposals to reduce GHG emissions. Carbon dioxide emissions, including those from the combustion of fossil fuels, comprise the largest percentage of GHG emissions.

In July 2007, Act 234, which requires a statewide reduction of GHG emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990, became law in Hawaii. The electric utilities are participating in a Task Force established under Act 234, which is charged with developing a work plan and regulatory approach to reduce GHG emissions, as well as in initiatives aimed at reducing their GHG emissions, such as those to be undertaken under the Energy Agreement. A Task Force consultant prepared a work plan, which was submitted to the Hawaii Legislature in December 2009. Because the regulations implementing Act 234 have not yet been developed or promulgated, management cannot predict the impact of Act 234 on the electric utilities and the Company, but compliance costs could be significant.

In June 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act of 2009 (ACES). Among other things, ACES establishes a declining cap on GHG emissions requiring a 3% emissions reduction by 2012 that increases periodically to 83% by 2050. ACES also establishes a trading and offset scheme for GHG allowances. The trading program combined with the declining cap is known as a cap and trade approach to emissions reduction. In September 2009, the U.S. Senate began consideration of the Clean Energy Jobs and American Power Act, which also includes cap and trade provisions. Since then, several other approaches to GHG emission reduction have been either introduced or discussed in the U.S. Senate; however, no legislation has yet been enacted.

On September 22, 2009, the EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule, which requires that sources emitting GHGs above certain threshold levels monitor and report GHG emissions beginning in 2010. In December 2009, the EPA made the finding that motor vehicle GHG emissions endanger public health or welfare. Management believes the EPA will make the same or similar endangerment finding regarding GHG emissions from stationary sources like the utilities generating units.

In addition, the Prevention of Significant Deterioration (PSD) permit program of the CAA applies to designated air pollutants from new or modified stationary sources, such as utility electrical generation units. In June 2010, the EPA issued its Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (GHG Tailoring Rule) that created new thresholds for GHG emissions from new and existing facilities. States may need to increase fees to cover the increased level of activity caused by this rule. The GHG Tailoring Rule requires a number of existing HECO, HELCO and MECO facilities that are not currently subject to the Covered Source Permit program to submit an initial Covered Source Permit application to the DOH within one year. The EPA has stated that the PSD program will apply to GHG emissions on January 2, 2011 because that is the date the federal GHG emission standards for motor vehicles (Tailpipe Rule) take effect.

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The EPA is proposing and adopting these rules on a parallel track with federal climate change legislation. If comprehensive GHG emission control legislation is not adopted, then these (and other future) EPA rules would likely be finalized and be applicable to the utilities. In particular, the Company anticipates that, unless comprehensive GHG legislation is adopted, permitting after January 2, 2011 of new or modified stationary sources that have the potential to emit GHGs in greater quantities than the thresholds in the GHG Tailoring Rule will entail GHG emissions evaluation, analysis, and potentially control requirements.

HECO and its subsidiaries have taken, and continue to identify opportunities to take, direct action to reduce GHG emissions from their operations, including, but not limited to, supporting demand-side management (DSM) programs that foster energy efficiency, using renewable resources for energy production and purchasing power from IPPs generated by renewable resources, committing to burn renewable biodiesel in HECO s CIP CT-1, using biodiesel for startup and shutdown of selected MECO generation units, and pursuing plans to test biofuel blends in other HECO and MECO generating units. Management is unable to evaluate the ultimate impact on the Company s operations of eventual GHG regulation. However, the Company believes that the various initiatives it is undertaking will provide a sound basis for managing the electric utilities carbon footprint and meeting GHG reduction goals that will ultimately emerge.

While the timing, extent and ultimate effects of climate change cannot be determined with any certainty, climate change is predicted to result in sea level rise, which could potentially impact coastal and other low-lying areas (where much of the Company s electric infrastructure is sited), and could cause erosion of beaches, saltwater intrusion into aquifers and surface ecosystems, higher water tables and increased flooding and storm damage due to heavy rainfall. The effects of climate change on the weather (for example, floods or hurricanes), sea levels, and water availability and quality have the potential to materially adversely affect the results of operations, financial condition and liquidity of the Company. For example, severe weather could cause significant harm to the Company s physical facilities.

Given Hawaii s unique geographic location and its isolated electric grids, physical risks of the type associated with climate change have been considered by the Company in the planning, design, construction, operation and maintenance of its facilities. To ensure the reliability of each island s grid, the Company designs and constructs its electric generation system with greater levels of redundancy than is typical for U.S. mainland, interconnected systems. Although a major natural disaster could have severe financial implications, such risks have existed since the Company s inception and the Company makes a concerted effort to prepare for a fast response in the event of an emergency.

The Company is undertaking an adaptation survey of its facilities as a step in developing a longer-term strategy for responding to the consequences of global climate change.

BlueEarth Biofuels LLC. BlueEarth Maui Biodiesel LLC (BlueEarth Maui), a joint venture to pursue biodiesel development, was formed in early 2008 between BlueEarth Biofuels LLC (BlueEarth) and Uluwehiokama Biofuels Corp. (UBC), a non-regulated subsidiary of HECO. UBC invested $400,000 in BlueEarth Maui for a minority ownership interest. MECO began negotiating with BlueEarth Maui for a biodiesel fuel purchase contract, however, negotiations stalled. In October 2008, BlueEarth filed a civil action in federal district court against MECO, HECO and others alleging claims based on the parties failure to have reached agreement on the biodiesel supply and related land agreements. The lawsuit seeks damages and equitable relief. A trial date has been scheduled for June 2011. The project was terminated because the litigation was filed and UBC s investment in the venture was written off in 2009.

Asset retirement obligations. In July 2009, HECO hired an industrial hygienist to conduct an inspection of HECO s Honolulu power plant, which inspection indicated that retired Generating Units Nos. 5 and 7 at the plant were now deteriorating. The industrial hygienist recommended removing asbestos-containing materials and lead-based paint. Based on prior assessments, the timing of the removal of asbestos and lead-based

paint had not been estimable. Based on the inspection, however, HECO now intends to remove Units Nos. 5 and 7, including abating the asbestos and lead-based paint, over the period 2010 to 2013. Accordingly, HECO recorded an asset retirement obligation in September 2009. In August 2010, HECO recorded a similar asset retirement obligation related to removing retired Generating Units Nos. 1 and 2 at HECO s Waiau power plant, including abating the asbestos and

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lead-based paint, over the period 2011 to 2013. As of September 30, 2010, HECO s asset retirement obligations related to Honolulu power plant Units Nos. 5 and 7, and Waiau power plant Units 1 and 2, were $35 million and $12 million, respectively.

Collective bargaining agreements. As of September 30, 2010, approximately 55% of the electric utilities employees were members of the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, Unit 8, which is the only union representing employees of the Company. On March 1, 2008, members of the union ratified collective bargaining and benefit agreements with HECO, HELCO and MECO. The agreements cover a three-year term, from November 1, 2007 to October 31, 2010, and provide for non-compounded wage increases of 3.5% effective November 1, 2007, 4% effective January 1, 2009 and 4.5% effective January 1, 2010. The utilities are currently renegotiating the contract with the union.

Limited insurance. HECO and its subsidiaries purchase insurance to protect themselves against loss 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 transmission and distribution systems (excluding substation buildings and contents) have a replacement value roughly estimated at $5 billion and are uninsured. Similarly, HECO, HELCO and MECO have no business interruption insurance. If a hurricane or other uninsured catastrophic natural disaster were to 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, financial condition and liquidity could be materially adversely impacted. Also, if a series of losses occurred, each of which were subject to an insurance deductible amount, or if the maximum limit of the available insurance were substantially exceeded, the utilities could incur losses in amounts that would have a material adverse effect on their results of operations, financial condition and liquidity.

6 • Cash flows

Supplemental disclosures of cash flow information. For the nine months ended September 30, 2010 and 2009, HECO and its subsidiaries paid interest amounting to $42 million and $29 million, respectively.

For the nine months ended September 30, 2010 and 2009, HECO and its subsidiaries paid income taxes amounting to $37 million and $12 million, respectively. The increase in income taxes paid was primarily due to higher operating income in 2010 and estimated tax payments made through September 2010 without the retroactive effect of 2010 bonus depreciation (which was enacted after the payment of September 2010 estimated taxes).

Supplemental disclosure of noncash activities. The allowance for equity funds used during construction, which was charged to construction in progress as part of the cost of electric utility plant, amounted to $4.8 million and $10.4 million for the nine months ended September 30, 2010 and 2009, respectively.

7 • Recent accounting pronouncements and interpretations

For a discussion of recent accounting pronouncements and interpretations, see Note 12 of HEI s Notes to Consolidated Financial Statements.

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8 • Fair value measurements

Fair value estimates are based on the price that would be received to sell an asset, or paid upon the transfer of a liability, in an orderly transaction between market participants at the measurement date. The fair value estimates are generally determined based on assumptions that market participants would use in pricing the asset or liability and are based on market data obtained from independent sources. However, in certain cases, the electric utilities use their own assumptions about market participant assumptions based on the best information available in the circumstances. These valuations are estimates at a specific point in time, based on relevant market information, information about the financial instrument and judgments regarding future expected loss experience, economic conditions, risk characteristics of various financial instruments and other factors. These estimates do not reflect any premium or discount that could result if the electric utilities were to sell their entire holdings of a particular financial instrument at one time. Because no market exists for a portion of the electric utilities financial instruments, fair value estimates cannot be determined with precision. Changes in the underlying assumptions used, including discount rates and estimates of future cash flows, 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, but have not been considered in determining such fair values.

The electric utilities 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 cash equivalents and short-term borrowings. The carrying amount approximated fair value because of the short maturity of these instruments.

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

Off-balance sheet financial instruments. Fair value of HECO-obligated preferred securities of trust subsidiaries was based on quoted market prices.

The estimated fair values of the financial instruments held or issued by the electric utilities were as follows:

	September 30, 2010		December 31, 2009	
(in thousands)	Carrying amount	Estimated fair value	Carrying amount	Estimated fair value
Financial assets				
Cash and cash equivalents	$ 35,044	$ 35,044	$ 73,578	$ 73,578
Financial liabilities				
Long-term debt, net, including amounts due within one year	1,057,911	1,071,586	1,057,815	1,018,900

Off-balance sheet item				
HECO-obligated preferred securities of trust subsidiary	50,000	50,340	50,000	48,480

Fair value measurements on a nonrecurring basis. From time to time, the utilities may be required to measure certain assets at fair value on a nonrecurring basis in accordance with U.S. GAAP. These adjustments to fair value usually result from the application of lower-of-cost-or-market accounting or write-downs of individual assets. As of December 31, 2009, there were no adjustments to fair value for assets measured at fair value on a nonrecurring basis in accordance with U.S. GAAP. In the second quarter of 2010, HECO increased its asset retirement obligation (ARO) related to the Honolulu power plant by $11 million to $35 million (Level 3) due to an increase in estimated removal and abatement costs. In the third quarter of 2010, HECO increased its ARO by $13 million to $48 million (Level 3) due to the addition of estimated removal and abatement costs for two units at the Waiau power plant. The fair value of the ARO was determined by discounting the expected future cash flows using market-observable risk-free rates as adjusted by HECO s credit spread.

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9 • Credit agreement

Effective May 7, 2010, HECO entered into a revolving unsecured credit agreement establishing a line of credit facility of $175 million, with a letter of credit sub-facility, with a syndicate of eight financial institutions. The agreement has an initial term which expires on May 6, 2011, but its term will extend to May 7, 2013 if approved by the PUC. Any draws on the facility bear interest at the Adjusted LIBO Rate plus 200 basis points or the greatest of (a) the Prime Rate, (b) the sum of the Federal Funds Rate plus 50 basis points and (c) the Adjusted LIBO Rate for a one month Interest Period plus 100 basis points per annum, as defined in the agreement. Annual fees on the undrawn commitments are 30 basis points. The agreement contains provisions for revised pricing in the event of a ratings change. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have broad material adverse change clauses. However, the agreement does contain customary conditions that must be met in order to draw on it, including compliance with several covenants.

HECO s $175 million credit facility will be maintained to support the issuance of commercial paper, but also may be drawn to repay HECO s short-term indebtedness, to make loans to subsidiaries and for HECO s capital expenditures, working capital and general corporate purposes. HECO s $175 million syndicated credit facility expiring March 31, 2011 was terminated concurrently with the effectiveness of this new syndicated credit facility. In July 2010, HECO filed with the PUC an application seeking approval to extend the termination date of its credit agreement from May 6, 2011 to May 7, 2013.

10 • Reconciliation of electric utility operating income per HEI and HECO consolidated statements of income

	Three months ended September 30		Nine months ended September 30	
(in thousands)	**2010**	**2009**	**2010**	**2009**
Operating income from regulated and nonregulated activities before income taxes (per HEI consolidated statements of income)	$ 51,343	$ 54,172	$ 135,387	$ 117,404
Deduct:				
Income taxes on regulated activities	(14,818)	(15,957)	(36,972)	(33,228)
Revenues from nonregulated activities	(903)	(1,938)	(4,303)	(7,031)
Add: Expenses from nonregulated activities	492	373	3,259	777
Operating income from regulated activities after income taxes (per HECO consolidated statements of income)	$ 36,114	$ 36,650	$ 97,371	$ 77,922

11 • Consolidating financial information

HECO is not required to provide separate financial statements or other disclosures concerning HELCO and MECO to holders of the 2004 Debentures issued by HELCO and MECO to Trust III since all of their voting capital stock is owned, and their obligations with respect to these securities have been fully and unconditionally guaranteed, on a subordinated basis, by HECO. Consolidating information is provided below for these and other HECO subsidiaries for the periods ended and as of the dates indicated.

HECO also unconditionally guarantees HELCO s and MECO s obligations (a) to the State of Hawaii for the repayment of principal and interest on Special Purpose Revenue Bonds issued for the benefit of HELCO and MECO and (b) relating to the trust preferred securities of Trust III (see Note 2 above). HECO is also obligated, after the satisfaction of its obligations on its own preferred stock, to make dividend, redemption and liquidation payments on HELCO s and MECO s preferred stock if the respective subsidiary is unable to make such payments.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Three months ended September 30, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Operating revenues	$ 436,919	95,645	89,659				$ 622,223
Operating expenses							
Fuel oil	168,019	22,968	44,547				235,534
Purchased power	111,552	30,206	6,122				147,880
Other operation	44,949	7,848	9,868				62,665
Maintenance	20,258	4,995	5,365				30,618
Depreciation	21,197	9,127	5,953				36,277
Taxes, other than income taxes	40,924	8,904	8,489				58,317
Income taxes	8,665	3,327	2,826				14,818
	415,564	87,375	83,170				586,109
Operating income	21,355	8,270	6,489				36,114
Other income							
Allowance for equity funds used during construction	923	129	145				1,197
Equity in earnings of subsidiaries	9,454					(9,454)	
Other, net	267	147	120	(2)	(2)	(20)	510
	10,644	276	265	(2)	(2)	(9,474)	1,707
Interest and other charges							
Interest on long-term debt	9,130	2,985	2,268				14,383
Amortization of net bond premium and expense	512	160	127				799
Other interest charges	476	92	105			(20)	653
Allowance for borrowed funds used during construction	(369)	(66)	(57)				(492)
	9,749	3,171	2,443			(20)	15,343
Net income (loss)	22,250	5,375	4,311	(2)	(2)	(9,454)	22,478
Preferred stock dividend of subsidiaries		133	95				228
Net income (loss) attributable to HECO	22,250	5,242	4,216	(2)	(2)	(9,454)	22,250
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 21,980	5,242	4,216	(2)	(2)	(9,454)	$ 21,980

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Three months ended September 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Operating revenues	$ 380,722	87,631	78,149				$ 546,502
Operating expenses							
Fuel oil	131,717	19,370	35,632				186,719
Purchased power	101,625	26,442	6,380				134,447
Other operation	43,854	8,055	9,264				61,173
Maintenance	15,844	5,794	4,330				25,968
Depreciation	19,928	8,253	7,376				35,557
Taxes, other than income taxes	34,703	8,052	7,276				50,031
Income taxes	10,596	3,262	2,099				15,957
	358,267	79,228	72,357				509,852
Operating income	22,455	8,403	5,792				36,650
Other income							
Allowance for equity funds used during construction	2,376	21	231				2,628
Equity in earnings of subsidiaries	8,874					(8,874)	
Other, net	1,666	68	134	(3)	(134)	(74)	1,657
	12,916	89	365	(3)	(134)	(8,948)	4,285
Interest and other charges							
Interest on long-term debt	8,659	2,674	2,268				13,601
Amortization of net bond premium and expense	451	165	119				735
Other interest charges	503	142	134			(74)	705
Allowance for borrowed funds used during construction	(1,026)	4	(96)				(1,118)
	8,587	2,985	2,425			(74)	13,923
Net income (loss)	26,784	5,507	3,732	(3)	(134)	(8,874)	27,012
Preferred stock dividend of subsidiaries		133	95				228
Net income (loss) attributable to HECO	26,784	5,374	3,637	(3)	(134)	(8,874)	26,784
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 26,514	5,374	3,637	(3)	(134)	(8,874)	$ 26,514

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Nine months ended September 30, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Operating revenues	$ 1,220,589	276,120	254,320				$ 1,751,029
Operating expenses							
Fuel oil	464,482	69,600	128,526				662,608
Purchased power	302,106	83,671	18,398				404,175
Other operation	130,795	25,097	26,271				182,163
Maintenance	55,898	16,305	17,691				89,894
Depreciation	65,022	27,380	21,166				113,568
Taxes, other than income taxes	114,481	25,741	24,056				164,278
Income taxes	25,417	7,369	4,186				36,972
	1,158,201	255,163	240,294				1,653,658
Operating income	62,388	20,957	14,026				97,371
Other income							
Allowance for equity funds used during construction	4,081	330	406				4,817
Equity in earnings of subsidiaries	18,173					(18,173)	
Other, net	2,271	402	(464)	(6)	(12)	(68)	2,123
	24,525	732	(58)	(6)	(12)	(18,241)	6,940
Interest and other charges							
Interest on long-term debt	27,391	8,954	6,804				43,149
Amortization of net bond premium and expense	1,429	395	368				2,192
Other interest charges	1,342	288	299			(68)	1,861
Allowance for borrowed funds used during construction	(1,733)	(168)	(160)				(2,061)
	28,429	9,469	7,311			(68)	45,141
Net income (loss)	58,484	12,220	6,657	(6)	(12)	(18,173)	59,170
Preferred stock dividend of subsidiaries		400	286				686
Net income (loss) attributable to HECO	58,484	11,820	6,371	(6)	(12)	(18,173)	58,484
Preferred stock dividends of HECO	810						810
Net income (loss) for common stock	$ 57,674	11,820	6,371	(6)	(12)	(18,173)	$ 57,674

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Nine months ended September 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Operating revenues	$ 986,578	251,936	215,109				$ 1,453,623
Operating expenses							
Fuel oil	317,456	50,896	95,541				463,893
Purchased power	261,799	86,580	15,741				364,120
Other operation	131,574	26,767	28,410				186,751
Maintenance	49,950	17,428	14,184				81,562
Depreciation	61,523	24,754	22,129				108,406
Taxes, other than income taxes	93,659	23,708	20,374				137,741
Income taxes	22,515	6,402	4,311				33,228
	938,476	236,535	200,690				1,375,701
Operating income	48,102	15,401	14,419				77,922
Other income							
Allowance for equity funds used during construction	8,254	1,530	569				10,353
Equity in earnings of subsidiaries	18,083					(18,083)	
Other, net	5,713	1,007	331	(11)	(147)	(400)	6,493
	32,050	2,537	900	(11)	(147)	(18,483)	16,846
Interest and other charges							
Interest on long-term debt	23,995	6,659	6,804				37,458
Amortization of net bond premium and expense	1,256	475	361				2,092
Other interest charges	1,516	591	341			(400)	2,048
Allowance for borrowed funds used during construction	(3,566)	(666)	(235)				(4,467)
	23,201	7,059	7,271			(400)	37,131
Net income (loss)	56,951	10,879	8,048	(11)	(147)	(18,083)	57,637
Preferred stock dividend of subsidiaries		400	286				686
Net income (loss) attributable to HECO	56,951	10,479	7,762	(11)	(147)	(18,083)	56,951
Preferred stock dividends of HECO	810						810
Net income (loss) for common stock	$ 56,141	10,479	7,762	(11)	(147)	(18,083)	$ 56,141

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

September 30, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Assets							
Utility plant, at cost							
Land	$ 43,248	5,108	3,015				$ 51,371
Plant and equipment	2,954,843	1,005,755	871,811				4,832,409
Less accumulated depreciation	(1,120,269)	(400,922)	(394,072)				(1,915,263)
Construction in progress	73,799	19,389	12,304				105,492
Net utility plant	1,951,621	629,330	493,058				3,074,009
Investment in wholly owned subsidiaries, at equity	469,495					(469,495)	
Current assets							
Cash and cash equivalents	32,260	2,053	635	90	6		35,044
Advances to affiliates	7,050		19,500			(26,550)	
Customer accounts receivable, net	100,067	22,266	19,345				141,678
Accrued unbilled revenues, net	66,475	14,764	14,627				95,866
Other accounts receivable, net	7,159	3,061	530			(3,909)	6,841
Fuel oil stock, at average cost	91,106	13,313	16,811				121,230
Materials & supplies, at average cost	19,449	4,288	12,556				36,293
Prepayments and other	51,392	21,503	9,194				82,089
Total current assets	374,958	81,248	93,198	90	6	(30,459)	519,041
Other long-term assets							
Regulatory assets	311,329	57,195	53,653				422,177
Unamortized debt expense	9,543	2,736	2,156				14,435
Other	36,242	8,027	15,397				59,666
Total other long-term assets	357,114	67,958	71,206				496,278
	$ 3,153,188	778,536	657,462	90	6	(499,954)	$ 4,089,328
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,325,892	244,695	224,707	88	5	(469,495)	$ 1,325,892
Cumulative preferred stock not subject to mandatory redemption	22,293	7,000	5,000				34,293
Long-term debt, net	672,252	211,271	174,388				1,057,911
Total capitalization	2,020,437	462,966	404,095	88	5	(469,495)	2,418,096
Current liabilities							
Short-term borrowings-affiliate	19,500	7,050				(26,550)	
Accounts payable	83,814	19,033	13,863				116,710
Interest and preferred dividends payable	14,194	4,318	3,953			(4)	22,461
Taxes accrued	98,312	28,690	23,350				150,352
Other	33,685	7,729	14,587	2	1	(3,905)	52,099
Total current liabilities	249,505	66,820	55,753	2	1	(30,459)	341,622
Deferred credits and other liabilities							
Deferred income taxes	180,060	43,960	20,435				244,455
Regulatory liabilities	194,910	55,389	39,269				289,568
Unamortized tax credits	32,988	12,922	12,173				58,083
Retirement benefits liability	219,691	34,470	38,908				293,069
Other	69,779	30,253	12,998				113,030

Total deferred credits and other liabilities	697,428	176,994	123,783				998,205
Contributions in aid of construction	185,818	71,756	73,831				331,405
	$ 3,153,188	778,536	657,462	90	6	(499,954) $	4,089,328

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

December 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Assets							
Utility plant, at cost							
Land	$ 43,075	5,109	4,346				$ 52,530
Plant and equipment	2,833,296	995,585	867,376				4,696,257
Less accumulated depreciation	(1,081,441)	(379,526)	(387,449)				(1,848,416)
Construction in progress	115,644	10,920	6,416				132,980
Net utility plant	1,910,574	632,088	490,689				3,033,351
Investment in wholly owned subsidiaries, at equity	462,006					(462,006)	
Current assets							
Cash and cash equivalents	70,981	2,006	474	98	19		73,578
Advances to affiliates	20,100		11,000			(31,100)	
Customer accounts receivable, net	89,365	24,502	19,419				133,286
Accrued unbilled revenues, net	58,022	13,648	12,606				84,276
Other accounts receivable, net	5,967	2,294	1,317			(1,129)	8,449
Fuel oil stock, at average cost	49,847	12,640	16,174				78,661
Materials & supplies, at average cost	18,378	4,006	13,524				35,908
Prepayments and other	10,163	4,268	2,614			(844)	16,201
Total current assets	322,823	63,364	77,128	98	19	(33,073)	430,359
Other long-term assets							
Regulatory assets	312,953	59,372	54,537				426,862
Unamortized debt expense	9,392	2,679	2,217				14,288
Other	47,502	9,718	16,312				73,532
Total other long-term assets	369,847	71,769	73,066				514,682
	$ 3,065,250	767,221	640,883	98	19	(495,079)	$ 3,978,392
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,306,408	240,576	221,319	94	17	(462,006)	$ 1,306,408
Cumulative preferred stock not subject to mandatory redemption	22,293	7,000	5,000				34,293
Long-term debt, net	672,200	211,248	174,367				1,057,815
Total capitalization	2,000,901	458,824	400,686	94	17	(462,006)	2,398,516
Current liabilities							
Short-term borrowings-affiliate	11,000	20,100				(31,100)	
Accounts payable	103,073	17,369	12,269				132,711
Interest and preferred dividends payable	14,186	4,088	2,954			(5)	21,223
Taxes accrued	101,288	31,274	24,374			(844)	156,092
Other	28,956	8,670	11,684	4	2	(1,124)	48,192
Total current liabilities	258,503	81,501	51,281	4	2	(33,073)	358,218
Deferred credits and other liabilities							
Deferred income taxes	141,160	25,984	13,459				180,603
Regulatory liabilities	196,284	52,669	39,261				288,214
Unamortized tax credits	31,393	12,886	12,591				56,870
Retirement benefits liability	221,311	35,584	39,728				296,623
Other	36,113	30,207	11,484				77,804

Total deferred credits and other liabilities	626,261	157,330	116,523				900,114
Contributions in aid of construction	179,585	69,566	72,393				321,544
	$ 3,065,250	767,221	640,883	98	19	(495,079) $	3,978,392

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Common Stock Equity (unaudited)

Nine months ended September 30, 2010

(in thousands)		HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations		HECO Consolidated
Balance, December 31, 2009	$	1,306,408	240,576	221,319	94	17	(462,006)	$	1,306,408
Comprehensive income (loss):									
Net income (loss) for common stock		57,674	11,820	6,371	(6)	(12)	(18,173)		57,674
Retirement benefit plans:									
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes		2,819	593	461			(1,054)		2,819
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits		(2,640)	(579)	(443)			1,022		(2,640)
Comprehensive income (loss)		57,853	11,834	6,389	(6)	(12)	(18,205)		57,853
Common stock dividends		(38,360)	(7,710)	(3,001)			10,711		(38,360)
Common stock issue expenses		(9)	(5)				5		(9)
Balance, September 30, 2010	$	1,325,892	244,695	224,707	88	5	(469,495)	$	1,325,892

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Common Stock Equity (unaudited)

Nine months ended September 30, 2009

(in thousands)		HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations		HECO Consolidated
Balance, December 31, 2008	$	1,188,842	221,405	215,382	105	141	(437,033)	$	1,188,842
Comprehensive income (loss):									
Net income (loss) for common stock		56,141	10,479	7,762	(11)	(147)	(18,083)		56,141
Retirement benefit plans:									
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes		8,008	1,206	989			(2,195)		8,008
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits		(7,835)	(1,193)	(971)			2,164		(7,835)
Comprehensive income (loss)		56,314	10,492	7,780	(11)	(147)	(18,114)		56,314
Capital stock expense		(7)	(2)	(1)			3		(7)
Common stock dividends		(32,756)		(4,264)			4,264		(32,756)
Issuance of common stock						25	(25)		
Balance, September 30, 2009	$	1,212,393	231,895	218,897	94	19	(450,905)	$	1,212,393

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Nine months ended September 30, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Elimination addition to (deduction from) cash flows	HECO Consolidated
Cash flows from operating activities:							
Net income (loss)	$ 58,484	12,220	6,657	(6)	(12)	(18,173)	$ 59,170
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(18,248)					18,173	(75)
Common stock dividends received from subsidiaries	10,786					(10,711)	75
Depreciation of property, plant and equipment	65,022	27,380	21,166				113,568
Other amortization	3,686	2,595	(921)				5,360
Changes in deferred income taxes	45,875	20,643	8,202				74,720
Changes in tax credits, net	1,992	132	(185)				1,939
Allowance for equity funds used during construction	(4,081)	(330)	(406)				(4,817)
Increase in cash overdraft			884				884
Changes in assets and liabilities:							
Decrease (increase) in accounts receivable	(11,894)	1,469	861			2,780	(6,784)
Increase in accrued unbilled revenues	(8,453)	(1,116)	(2,021)				(11,590)
Increase in fuel oil stock	(41,259)	(673)	(637)				(42,569)
Decrease (increase) in materials and supplies	(1,071)	(282)	968				(385)
Increase in regulatory assets	(1,801)	(1,144)	(324)				(3,269)
Increase (decrease) in accounts payable	(19,259)	1,664	1,594				(16,001)
Changes in prepaid and accrued income and utility revenue taxes	(45,651)	(2,567)	(6,984)				(55,202)
Changes in other assets and liabilities	21,933	(20,580)	2,845	(2)	(1)	(2,780)	1,415
Net cash provided by (used in) operating activities	56,061	39,411	31,699	(8)	(13)	(10,711)	116,439
Cash flows from investing activities:							
Capital expenditures	(86,893)	(22,998)	(21,249)				(131,140)
Contributions in aid of construction	10,079	5,073	1,623				16,775
Other	657						657
Advances from (to) affiliates	13,050		(8,500)			(4,550)	
Net cash used in investing activities	(63,107)	(17,925)	(28,126)			(4,550)	(113,708)
Cash flows from financing activities:							
Common stock dividends	(38,360)	(7,710)	(3,001)			10,711	(38,360)
Preferred stock dividends of HECO and subsidiaries	(810)	(400)	(286)				(1,496)
Net increase (decrease) in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	8,500	(13,050)				4,550	

Other	(1,005)	(279)	(125)				(1,409)
Net cash used in financing activities	(31,675)	(21,439)	(3,412)			15,261	(41,265)
Net increase (decrease) in cash and cash equivalents	(38,721)	47	161	(8)	(13)		(38,534)
Cash and cash equivalents, beginning of period	70,981	2,006	474	98	19		73,578
Cash and cash equivalents, end of period	$ 32,260	2,053	635	90	6	$	35,044

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Nine months ended September 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Cash flows from operating activities							
Net income (loss)	$ 56,951	10,879	8,048	(11)	(147)	(18,083)	$ 57,637
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(18,158)					18,083	(75)
Common stock dividends received from subsidiaries	4,339					(4,264)	75
Depreciation of property, plant and equipment	61,523	24,754	22,129				108,406
Other amortization	2,804	2,554	2,344				7,702
Changes in deferred income taxes	6,081	5,414	1,037				12,532
Changes in tax credits, net	115	(332)	(284)				(501)
Allowance for equity funds used during construction	(8,254)	(1,530)	(569)				(10,353)
Changes in assets and liabilities:							
Decrease in accounts receivable	16,450	5,969	6,017		11	3,976	32,423
Decrease in accrued unbilled revenues	8,199	4,319	1,665				14,183
Decrease (increase) in fuel oil stock	14,029	(377)	(3,826)				9,826
Decrease (increase) in materials and supplies	(2,284)	286	173				(1,825)
Increase in regulatory assets	(7,460)	(2,973)	(3,396)				(13,829)
Increase (decrease) in accounts payable	2,600	(8,992)	1,440				(4,952)
Changes in prepaid and accrued income and utility revenue taxes	(42,546)	(9,342)	(10,500)				(62,388)
Changes in other assets and liabilities	12,299	(4,439)	(509)	(13)	(2)	(3,976)	3,360
Net cash provided by (used in) operating activities	106,688	26,190	23,769	(24)	(138)	(4,264)	152,221
Cash flows from investing activities							
Capital expenditures	(159,900)	(55,283)	(22,481)				(237,664)
Contributions in aid of construction	4,253	1,993	1,226				7,472
Advances from (to) affiliates	36,650		2,000			(38,650)	
Other	221				119		340
Investment in consolidated subsidiary	(25)					25	
Net cash provided by (used in) investing activities	(118,801)	(53,290)	(19,255)		119	(38,625)	(229,852)
Cash flows from financing activities							
Common stock dividends	(32,756)		(4,264)			4,264	(32,756)
Preferred stock dividends of HECO and subsidiaries	(810)	(400)	(286)				(1,496)
Proceeds from issuance of long-term debt	90,000	63,186					153,186
Proceeds from issuance of common stock					25	(25)	
Net increase in short-term borrowings from affiliate with original maturities of three months or less	(32,850)	(36,650)				38,650	(30,850)

Decrease in cash overdraft	(9,847)						(9,847)
Other	(1,018)	(2)	(1)				(1,021)
Net cash provided by (used in) financing activities	12,719	26,134	(4,551)		25	42,889	77,216
Net increase (decrease) in cash and cash equivalents	606	(966)	(37)	(24)	6		(415)
Cash and cash equivalents, beginning of period	2,264	3,148	1,349	123	17		6,901
Cash and cash equivalents, end of period	$ 2,870	2,182	1,312	99	23	$	6,486

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion updates Management s Discussion and Analysis of Financial Condition and Results of Operations incorporated by reference in HEI s and HECO s Form 10-K for the year ended December 31, 2009 and should be read in conjunction with the 2009 annual consolidated financial statements of HEI and HECO and notes thereto as well as the quarterly financial statements and notes thereto included in the Forms 10-Q for the first, second and third quarters of 2010.

HEI Consolidated

RESULTS OF OPERATIONS

(in thousands, except per share amounts)	Three months ended September 30 2010	2009	% change	Primary reason(s) for significant change*
Revenues	$ 694,541	$ 620,313	12	Increase for the electric utility segment, partly offset by a decrease for the bank segment
Operating income	72,631	68,639	6	Increase for the bank segment, partly offset by a decrease for the electric utility segment
Net income for common stock	32,449	33,483	(3)	Higher operating income, more than offset by lower AFUDC, higher interest expense other than on deposit liabilities and other bank borrowings and higher income taxes**
Basic earnings per common share	0.35	$ 0.37	(5)	Lower net income and higher weighted average shares outstanding
Weighted-average number of common shares outstanding	93,699	91,522	2	Issuances of shares under the HEI Dividend Reinvestment and Stock Purchase Plan and Company employee plans

(in thousands, except per share amounts)	Nine months ended September 30 2010	2009	% change	Primary reason(s) for significant change*
Revenues	$ 1,969,245	$ 1,690,011	17	Increase for the electric utility segment, partly offset by a decrease for the bank segment
Operating income	196,969	148,352	33	Increase for the electric utility and the bank segments
Net income for common stock	88,837	69,357	28	Higher operating income, partly offset by lower AFUDC, higher interest

				expense other than on deposit liabilities and other bank borrowings and higher income taxes**
Basic earnings per common share	$ 0.95	$ 0.76	25	Higher net income, partly offset by higher weighted average shares outstanding
Weighted-average number of common shares outstanding	93,148	91,173	2	Issuances of shares under the HEI Dividend Reinvestment and Stock Purchase Plan and Company employee plans

* Also, see segment discussions which follow.

** The Company s effective tax rates (federal and state) for the third quarters of 2010 and 2009 were 38% and 36%, respectively. The Company s effective tax rates (federal and state) for the first nine months of 2010 and 2009 were 36% and 34%, respectively.

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Dividends. The payout ratios for 2009 and the first nine months of 2010 were 137% and 98%, respectively. HEI currently expects to maintain the dividend at its present level; however, the HEI Board of Directors evaluates the dividend quarterly and considers many factors in the evaluation, including but not limited to the Company s results of operations, the long-term prospects for the Company, and current and expected future economic conditions.

Economic conditions.

Note: The statistical data in this section is from public third-party sources (e.g., Department of Business, Economic Development and Tourism (DBEDT); University of Hawaii Economic Research Organization (UHERO); U.S. Bureau of Labor Statistics; Blue Chip Economic Indicators; Blue Chip Financial Forecasts; Hawaii Tourism Authority (HTA); Honolulu Board of REALTORS®; and national and local newspapers).

Although the U.S. economy has grown for four consecutive quarters, the pace of economic expansion remains relatively weak. According to the October 2010 Blue Chip Economic Indicators, gross domestic product (GDP) grew at a seasonally adjusted rate of 1.7% in the second quarter of 2010 and is estimated to be 1.9% in the third quarter. The latest projection for the fourth quarter is 2.3% and for the first quarter of 2011 is 2.5%. The GDP consensus forecast continues to predict gradually improving economic growth through the first half of 2011.

Japan s economy grew modestly in the second quarter of 2010 with a seasonally annual adjusted rate of 1.5%. Growth in the third quarter was likely better due to improved consumer spending as a result of government subsidies. However, difficulties to sustain this growth lie ahead for the remainder of the year as real exports decline due to the strong yen, industrial production slows and the effects of the governmental fiscal stimulus dissipate. The Bank of Japan s cutting of interest rates to zero and announcing a $60 billion fund to purchase financial assets signify concern that more government assistance is needed to bolster the economy.

Economic growth in both the U.S. and Japan, albeit slow, are positive indicators for the Hawaii economy. State economists are projecting that Hawaii s economy will continue to expand but at a modest pace through 2011.

The outlook for two of Hawaii s major industries, visitors and construction, remains mixed. August 2010 marks the ninth consecutive month of positive growth since December 2009 in visitors by air with August 2010 capping off a relatively strong summer as compared to last year. Boosted by additional air seat capacity, total visitor arrivals were up 7.0% through the first eight months of 2010 as compared to the same period in 2009. Total visitor expenditures rose by 12.7% over the first eight months due to the increase in visitor arrivals and higher average daily visitor spending. Given the modest growth prospects in Hawaii s primary visitor markets, UHERO is projecting annual visitor arrivals for 2010 to be up by 6.7% over 2009 and annual expenditures to be up by 8.7%. DBEDT posts similar recovery predictions with arrivals at 4.6% and expenditures up 8.2% for 2010.

Hawaii s construction industry continues to struggle, but some positive signs have emerged in recent months. The decline in permitting has slowed and, following the delay in implementing federal stimulus spending, public contracts are now making a contribution to the industry. For the first eight months of 2010, the value of total private building permits in Hawaii declined by 5.8% from the same period in 2009 (values for permits for new residential construction and additions and alterations declined, but increased for commercial and industrial permits). Construction jobs were down 7.5% during this period, a slight improvement over the previous quarter.

Hawaii s housing market continues on its path to recovery following a challenging 2009. As of September 30, 2010, Oahu sales are up 20.4% for single-family homes and 21.4% for condominiums. Median sales prices are also showing improvement with increases of 4.2% over last year in single-family homes, but are flat for condominiums. Average days on the market have reduced significantly on Oahu to 32 days for the first nine months of 2010 compared to 52 days for the same period last year for single-family homes. Similarly on Maui, Kauai and the island of Hawaii, sales volume is up in the 30% range through August 2010, but median sales prices lag behind last year s prices for the three islands. Housing recovery should move forward slowly as interest rates remain low and affordability associated with lower prices present favorable purchase conditions. Inventory associated with the foreclosure situation and depressed prices of distressed sales, however, may hamper the recovery.

The job market continues to struggle and is expected to be the last aspect of the economy to show signs of recovery. Hawaii s seasonally adjusted unemployment rate in September 2010 was 6.3% and remains well below

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the national unemployment rate of 9.6% and is sixth lowest in the nation, but is high relative to historical periods. DBEDT projects total wage and salary jobs will decline by (0.6)% through 2010, followed by a modest 1% increase in 2011. Total jobs were down 0.8% in the first eight months of 2010 as compared to the same period last year. This reflects a slight improvement from the 1.4% decline in the first five months of 2010. Furloughs for county employees in all four counties were implemented for the fiscal year beginning July 1, 2010 and state employee furloughs, with the exception of teachers, continue.

Real personal income (which includes unemployment compensation) growth in Hawaii in 2010 is expected to be 0.4% according to UHERO s estimate and 0.3% according to DBEDT s estimate. This follows two consecutive years of decline in real personal income.

The price of a barrel of crude oil has fluctuated steadily over the year in the $70-$83 trading range and is expected to average $79 per barrel in the fourth quarter of 2010 according to the U.S. Energy Information Administration October 2010 Short-Term Energy Outlook.

Interest rates remained low during the first nine months of 2010 and are expected to remain low for the remainder of the year. The low level of interest rates continues to put downward pressure on yields of both loans and investments. Mortgage rates are currently seeing historical low levels, helping fuel some of the recovery in the housing market.

Retirement benefits. For the first nine months of 2010, the Company s and HECO and its subsidiaries defined benefit retirement plans assets generated a gain, after investment management fees, of 7.3%. The market value of the defined benefit retirement plans assets of the Company as of September 30, 2010 was $915 million compared to $874 million at December 31, 2009, an increase of approximately $41 million. The market value of the defined benefit retirement plans assets of HECO and its subsidiaries as of September 30, 2010 was $829 million compared to $792 million at December 31, 2009, an increase of approximately $37 million.

The Company and HECO and its subsidiaries estimate that the cash funding for their qualified defined benefit pension plans in 2010 will be about $28 million and $27 million, respectively, which should fully satisfy the minimum required contribution, including requirements of the utilities pension tracking mechanisms and the plans funding policy. Further, in June 2010, the President signed the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act, which provides, among other things, limited funding relief for defined benefit pension plans. The Company is currently analyzing options with regard to this law that would have the effect of lowering HECO s anticipated 2010 contributions to the pension plan by about $3 million.

Other factors could cause changes to the required contribution levels. The Pension Protection Act provides that if a pension plan s funded status falls below certain levels more conservative assumptions must be used to value obligations and restrictions on participant benefit accruals may be placed on the plans. If the plans fall below these thresholds, then, to avoid adverse consequences, funds in excess of the minimum required contribution may be contributed to the plan trust.

The following table reflects the sensitivity to the qualified defined benefit pension projected benefit obligation (PBO) as of December 31, 2010, associated with a change in the pension benefits discount rate actuarial assumption by the indicated basis points and constitutes forward-looking statements.

Actuarial Assumption	Change in 6.5% assumption in basis points	Impact on HEI Consolidated PBO	Impact on HECO Consolidated PBO
Pension benefits discount rate	- 50/-100	$66 million/$139 million	$61 million/$128 million

Commitments and contingencies. See Note 9 of HEI s Notes to Consolidated Financial Statements.

Recent accounting pronouncements and interpretations. See Note 12 of HEI s Notes to Consolidated Financial Statements.

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Other segment.

(in thousands)	Three months ended September 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ (14)	$ (74)	NM	
Operating loss	(3,101)	(3,222)	NM	Lower retirement benefit expense, partly offset by higher compensation expense and bank fees
Net loss	(4,824)	(4,354)	NM	See explanation for operating loss and higher interest expense due in part to higher borrowings

(in thousands)	Nine months ended September 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ (62)	$ (121)	NM	
Operating loss	(10,353)	(9,368)	NM	Higher compensation expense and bank fees, partly offset by lower retirement benefit expense
Net loss	(13,997)	(13,010)	NM	See explanation for operating loss and higher interest expense due in part to higher borrowings, partly offset by tax adjustments

NM Not meaningful.

The other business segment includes results of the stand-alone corporate operations of HEI and American Savings Holdings, Inc. (ASHI), both holding companies; Pacific Energy Conservation Services, Inc., a contract services company which provided windfarm operational and maintenance services to an affiliated electric utility until the windfarm was dismantled in the fourth quarter of 2010; HEI Properties, Inc., a company holding passive, venture capital investments; and The Old Oahu Tug Service, Inc., a maritime freight transportation company that ceased operations in 1999; as well as eliminations of intercompany transactions.

FINANCIAL CONDITION

Liquidity and capital resources. 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, its forecasted capital expenditures and investments, its expected retirement benefit plan contributions and other cash requirements in the foreseeable future.

The consolidated capital structure of HEI (excluding ASB s deposit liabilities and other borrowings) was as follows as of the dates indicated:

(dollars in millions)	September 30, 2010		December 31, 2009	
Short-term borrowings other than bank	$ 27	1%	$ 42	2%
Long-term debt, net other than bank	1,365	47	1,365	47
Preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,480	51	1,442	50
	$ 2,906	100%	$ 2,883	100%

HEI utilizes short-term debt, typically commercial paper, to support normal operations, to refinance commercial paper, to retire long-term debt, to pay dividends and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO s cash requirements, including the funding of loans by HECO to HELCO and MECO, but no such short-term loans to HECO were outstanding as of September 30, 2010. HEI periodically utilizes long-term debt, historically consisting of medium-term notes and other unsecured indebtedness, to fund investments in and loans to its subsidiaries to support their capital improvement or other requirements, to repay long-term and short-term indebtedness and for other corporate purposes.

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Effective May 7, 2010, HEI entered into a revolving unsecured credit agreement establishing a line of credit facility of $125 million, with a letter of credit sub-facility, expiring on May 7, 2013, with a syndicate of eight financial institutions. See Note 13 of HEI s Notes to Consolidated Financial Statements.

The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HEI s Issuer Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by Standard & Poor s (S&P) and Moody s Investors Service (Moody s), respectively) would result in a commitment fee increase of 5 basis points and an interest rate increase of 25 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1 by S&P or Moody s, respectively) would result in a commitment fee decrease of 10 basis points and an interest rate decrease of 25 basis points on any drawn amounts. The agreement contains customary conditions which must be met in order to draw on it, including compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HEI). In addition to customary defaults, HEI s failure to maintain its financial ratios, as defined in its agreement, or meet other requirements may result in an event of default. For example, under its agreement, it is an event of default if HEI fails to maintain a nonconsolidated Capitalization Ratio (funded debt) of 50% or less (ratio of 19% as of September 30, 2010, as calculated under the agreement) and Consolidated Net Worth of at least $975 million (Net Worth of $1.5 billion as of September 30, 2010, as calculated under the agreement).

HEI s short-term borrowings and HEI s line of credit facility were as follows for the period and as of the dates indicated:

(in millions)	Nine months ended September 30, 2010 Average balance	Balance September 30, 2010	Balance December 31, 2009
Short-term borrowings(1)			
HEI commercial paper	$ 38	$ 27	$ 42
HEI line of credit draws			
	$ 38	$ 27	$ 42
Line of credit facility (expiring May 7, 2013)		$ 125	$ 100
Undrawn capacity under HEI s line of credit facility		125	100

(1) This table does not include HECO s separate commercial paper issuances and line of credit facilities and draws, which are discussed below under Electric utility Financial Condition Liquidity and capital resources. At October 29, 2010, HEI s outstanding commercial paper balance was $37 million and its line of credit facility was undrawn.

Management believes that, if HEI s commercial paper ratings were to be downgraded, or if credit markets for commercial paper with HEI s ratings or in general were to tighten, it would be difficult and expensive for HEI to sell commercial paper or HEI might not be able to sell commercial paper in the future. Such limitations could cause HEI to draw on its syndicated credit facility instead, and the costs of such borrowings could increase under the terms of the credit agreement as a result of any such ratings downgrades. Similarly, if HEI s long-term debt ratings were to be downgraded, it would be difficult and more expensive for HEI to issue long-term debt. Such limitations and/or increased costs could materially adversely affect the results of operations and financial condition of HEI and its subsidiaries.

As of October 29, 2010, 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-3	P-2
Senior unsecured debt	BBB	Baa2

The above ratings reflect only the view, at the time the ratings are issued, of the applicable rating agency, from whom an explanation of the significance of such ratings may be obtained. Such 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.

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

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ratios) in determining the ratings of HEI securities. In May 2009, S&P revised HEI s outlook to negative from stable, and lowered its commercial paper rating to A-3 from A-2 . S&P indicated the rating actions reflected its view that the next two years are likely to be challenging for HEI s electric utilities, which HEI relies on for cash flows to service its own obligations, chiefly debt repayment and common stock distributions. S&P stated that the deterioration in the Hawaii economy is likely to weaken HEI s 2009 and 2010 consolidated metrics, which it observed have been only marginally supportive of the BBB corporate credit ratings currently assigned to HEI. In May 2010, S&P noted that [t]he negative outlook on Hawaiian Electric Industries Inc. (HEI) ratings reflects a weak consolidated financial profile that has been weighed down by the island recession and the need for more timely rate relief for HEI s electric utilities. We are concerned that 2010 could bring more underperformance for Hawaiian Electric Co. Inc. (HECO). S&P further stated, Given the importance of HECO to consolidated HEI cash flows, we would likely lower the corporate credit ratings on the parent and HECO one notch to BBB- unless we are able to see a clear path in 2010 to an improvement in HECO s credit metrics, which would at minimum require us to conclude that the electric utility is able to maintain funds from operations (FFO) to total debt of 15%, FFO interest coverage in the area of 3.5x, and leverage of less than 60%. S&P also indicated that [a]n upgrade is not likely due to HECO s need to restore its financial profile to levels consistent with the current rating.

On July 30, 2010, Moody s changed HEI s rating outlook to stable from negative and affirmed HEI s long-term and short-term (commercial paper) ratings. Moody s stated in its August 2, 2010 Credit Opinion on HEI:

The ratings affirmation and outlook change reflects the progress being made by the company and various stakeholders to transform the regulatory framework for HEI s electric utilities to a decoupling structure that will reduce sales volume risk and produce more timely recovery of invested capital and operations and maintenance (O&M) costs .

The stable rating outlook at HEI incorporates our belief that the regulatory transition underway in Hawaii will proceed in an orderly fashion with the Hawaii PUC issuing the final decoupling order during 2010. The stable rating outlook factors in our expectation that profitability initiatives at ASB will produce fairly predictable earnings enabling the bank to provide regular dividends to HEI without jeopardizing the bank s strong capital position.

[A] ny rating change for HEI will largely be driven by the utility s performance. HEI s ratings could be upgraded if the regulatory transition underway is executed in an orderly fashion leading to an improvement in credit metrics such that the HEI s cash flow to debt exceeds 18% and its cash flow coverage of interest is in excess of 4.0x on a sustainable basis.

The rating could be downgraded if the Hawaii PUC does not follow through with the regulatory transformation contemplated under the HCEI, including all elements of the decoupling mechanism. Quantitatively, the ratings could be downgraded if HEI s cash flow to debt declined to below 15% and its cash flow coverage of interest fell below 3.3x on a sustainable basis.

Issuances of common stock through the Hawaiian Electric Industries, Inc. Dividend Reinvestment and Stock Purchase Plan (DRIP), the Hawaiian Electric Industries Retirement Savings Plan (HEIRSP) and the ASB 401k Plan are important sources of capital for HEI. HEI raised $32 million through the issuance of approximately 1.4 million shares under these plans during the first nine months of 2010. HEI also makes registered public offerings of its common stock from time to time.

For the first nine months of 2010, net cash provided by operating activities of consolidated HEI was $190 million. Net cash used by investing activities for the same period was $79 million, primarily due to net increases in ASB investment securities and mortgage-related securities and HECO s consolidated capital expenditures, partly offset by a net decrease in ASB s loans held for investment. Net cash used in financing activities during this period was $227 million as a result of several factors, including net decreases in deposit liabilities and retail repurchase agreements and the payment of common stock dividends, partly offset by proceeds from the issuance of common stock under HEI plans and funds from short-term borrowings. Other than capital contributions from their parent company, intercompany services (and related intercompany payables and receivables), HECO s periodic short-term borrowings from HEI (and related interest) and the payment of dividends to HEI, the electric utility and bank segments are largely autonomous in their operating, investing and financing activities. (See the electric utility and bank segments discussions of their cash flows in their respective Financial condition Liquidity and capital resources sections below.) During the third quarter of 2010, HECO and ASB paid dividends to HEI of $11 million ($38 million year to date) and $20 million ($43 million year to date), respectively.

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Forecasted HEI consolidated net cash used in investing activities (excluding investing cash flows from ASB) for 2010 through 2012 consists primarily of the net capital expenditures of HECO and its subsidiaries. In addition to the funds required for the electric utilities construction programs, approximately $157 million will be required during 2011 through 2012 to repay maturing HEI medium-term notes, which are expected to be repaid with the proceeds from the issuance of commercial paper, bank borrowings, other medium-term notes, common stock issued under Company plans, and/or dividends from subsidiaries. In addition, approximately $57.5 million of HECO special purpose revenue bonds will be maturing in 2012, which bonds are expected to be repaid with proceeds from issuances of long-term debt. Additional debt and/or equity financing may be utilized to pay down commercial paper or other short-term borrowings or may be required to fund unanticipated expenditures not included in the 2010 through 2012 forecast, such as increases in the costs of or an acceleration of the construction of capital projects of the utilities, unanticipated utility capital expenditures that may be required by the Hawaii Clean Energy Initiative (HCEI) or new environmental laws and regulations, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements and higher tax payments that would result if certain 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).

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 the Company s control and could cause future results of operations to differ materially from historical results. For information about certain of these factors, see pages 16 to 17 (except for Limited insurance, which is updated in HEI s Quarterly Report on SEC Form 10-Q for the quarter ended March 31, 2010), 43 to 48, and 59 to 61 of HEI s MD&A, which is incorporated into Part II, Item 7 of HEI s 2009 Form 10-K by reference to HEI Exhibit 13 to HEI s Current Report on Form 8-K dated February 19, 2010.

Additional factors that may affect future results and financial condition are described above on pages iv and v under Forward-Looking Statements.

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.

In accordance with SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, management has identified the accounting policies it believes to be the most critical to the Company s financial statements that is, management believes that these policies 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.

For information about these material estimates and critical accounting policies, see pages 17 to 18, 48 to 50, and 61 to 62 of HEI s MD&A, which is incorporated into Part II, Item 7 of HEI s 2009 Form 10-K by reference to HEI Exhibit 13 to HEI s Current Report on Form 8-K dated February 19, 2010.

Following are discussions of the results of operations, liquidity and capital resources of the electric utility and bank segments.

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Electric utility

RESULTS OF OPERATIONS

(dollars in thousands, except per barrel amounts)	Three months ended September 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 623,126	$ 548,440	14	Higher fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers $(80 million), HECO test year 2009 interim rate increase $(8 million) and MECO test year 2010 interim rate increase $(2 million), partially offset by lower KWH sales $(18 million) and lower DSM costs recovered through a surcharge $(1 million)
Expenses				
Fuel oil	235,534	186,719	26	Higher fuel oil costs, partly offset by increased fuel efficiency and less KWHs generated
Purchased power	147,880	134,447	10	Higher fuel costs
Other operation	62,665	61,173	2	See Results three months ended September 30, 2010 below
Maintenance	30,618	25,968	18	See Results three months ended September 30, 2010 below
Depreciation	36,277	35,557	2	Additions to plant in service in 2009
Taxes, other than income taxes	58,317	50,031	17	Increase in revenues
Other	492	373	32	
Operating income	51,343	54,172	(5)	Higher expenses and lower sales, partly offset by HECO test year 2009 interim rate increase and MECO test year 2010 interim rate increase
Net income for common stock	21,980	26,514	(17)	Lower operating income, lower AFUDC due to HECO s CT-1 being placed in service in August 2009, and higher interest expense due to revenue bond drawdowns
Kilowatthour sales (millions)	2,497	2,572	(3)	
Wet-bulb temperature (Oahu average; degrees Fahrenheit)	69.8	71.5	(2)	
Cooling degree days (Oahu)	1,428	1,588	(10)	
Average fuel oil cost per barrel	$ 89.97	$ 66.40	35	
Customer accounts (end of period)	444,190	441,886	1	

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(dollars in thousands, except per barrel amounts)	Nine months ended September 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 1,755,332	$ 1,460,654	20	Higher fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers $(276 million), HECO test year 2009 interim rate increase $(42 million) and MECO test year 2010 interim rate increase $(2 million), partially offset by lower DSM costs recovered through a surcharge $(19 million) and lower KWH sales $(11 million)
Expenses				
Fuel oil	662,608	463,893	43	Higher fuel oil costs and more KWHs generated, partly offset by increased fuel efficiency
Purchased power	404,175	364,120	11	Higher fuel costs, partly offset by less KWHs purchased
Other operation	182,163	186,751	(2)	See Results nine months ended September 30, 2010 below
Maintenance	89,894	81,562	10	See Results nine months ended September 30, 2010 below
Depreciation	113,568	108,406	5	Additions to plant in service in 2009
Taxes, other than income taxes	164,278	137,741	19	Increase in revenues
Other	3,259	777	319	Write-down of investment in combined heat and power system in July 2010 (see Most recent rate requests below)
Operating income	135,387	117,404	15	HECO test year 2009 interim rate increase and MECO test year 2010 interim rate increase, partly offset by higher expenses and lower sales
Net income for common stock	57,674	56,141	3	Higher operating income, partly offset by lower AFUDC due to HECO s CT-1 and HELCO s ST-7 being placed in service in August and June 2009, respectively, and higher interest expense due to revenue bond drawdowns
Kilowatthour sales (millions)	7,144	7,203	(1)	
Wet-bulb temperature (Oahu average; degrees Fahrenheit)	67.8	68.5	(1)	
Cooling degree days (Oahu)	3,495	3,591	(3)	
Average fuel oil cost per barrel	$ 86.12	$ 59.21	45	

Note: The electric utilities had an effective tax rate for the third quarters of 2010 and 2009 of 40% and 37%, respectively. The electric utilities had an effective tax rate for the first nine months of 2010 and 2009 of 38% and 37%, respectively.

See Economic conditions in the HEI Consolidated section above.

Results three months ended September 30, 2010.Operating income for the third quarter of 2010 decreased 5% from the same period in 2009 due primarily to lower sales and higher Other operation and Maintenance (O&M) expenses, partly offset by interim rate increases for HECO and MECO.

Net income for common stock declined 17% compared with the same quarter last year for the same reasons given for Operating income above and due to lower AFUDC and higher interest expense. Kilowatthour sales were

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down 2.9% due primarily to cooler and less humid weather and resulted in an estimated net income decline of $4 million.

Higher O&M expenses ($7 million, excluding demand-side management (DSM) program costs) and higher financing costs and depreciation expense of ($4 million), primarily due to generating units put into service in the latter part of 2009, were largely offset by $10 million in rate relief granted in HECO s 2009 and MECO s 2010 test year rate cases. Higher Other operation expenses (excluding DSM program costs) included $1 million higher employee benefits and $1 million higher injuries and damages expense, partially offset by $2 million lower bad debt expense (resulting primarily from the recovery of amounts previously written off related to three large accounts). Maintenance expense increased $5 million primarily due to higher generating station maintenance and the replacement of critical equipment for system reliability.

Results nine months ended September 30, 2010.Operating income for the first nine months of 2010 increased 15% from the same period in 2009 due primarily to interim rate increases, improved fuel efficiency (primarily due to ST-7), partly offset by higher O&M expense (excluding DSM program costs) and lower KWH sales.

Net income for common stock increased 3% compared with the same period last year for the same reasons given for Operating income above, partly offset by lower AFUDC and higher interest expense. For the first nine months of 2010, KWH sales decreased 0.8% compared with the same period in 2009, primarily due to cooler and less humid weather. Management expects full year 2010 sales to be approximately 1% lower than 2009.

Interim rate relief granted in HECO s 2009 and MECO s 2010 test year rate cases amounted to approximately $44 million. Other operation expenses (excluding DSM program costs) increased by $22 million in the first nine months of 2010 compared to the same period in 2009 primarily due to $14 million higher administrative and general expenses (including $9 million higher employee benefit costs and $2 million higher injuries and damages expense) and $3 million higher production and transmission and distribution operations expenses, partly offset by $4 million of lower bad debt expense. Maintenance expense increased $8 million primarily due to $5 million higher production maintenance expense due to increases in the number and scope of generating unit overhauls and full year CT-1 cost and $4 million higher transmission and distribution maintenance, including the replacement of critical equipment for system reliability.

O&M expenses (excluding DSM program costs) for the year 2010 are expected to be approximately 13% higher than 2009 as the electric utilities expect higher production expenses, higher contract services costs, and higher transmission and distribution expenses to maintain system reliability. Also, additional expenses are expected for the costs to operate and maintain CIP CT-1, and are expected to be incurred for environmental compliance in response to existing compliance programs as well as numerous new, more stringent regulatory requirements, and to execute the provisions of the Energy Agreement. Partly offsetting the anticipated increased costs are lower DSM expenses (that are generally passed on to customers through a surcharge) due to the transition of energy efficiency programs to a third-party administrator in July 2009, and termination of lease payments for distributed generators in the latter half of 2010. HCEI-related initiatives appear to be progressing at a pace to achieve the state s clean energy goals under the HCEI.

The costs of supplying energy to meet demand and the maintenance costs required to sustain high availability of the aging generating units have been increasing.

Renewable energy strategy. The electric utilities have been taking actions intended to protect Hawaii s island ecology and counter global warming, while continuing to provide reliable power to customers, and committed to a number of related actions in the Energy Agreement. A three-pronged strategy supports attainment of the requirements and goals of the State of Hawaii Renewable Portfolio Standards (RPS), the Hawaii Global Warming Solutions Act of 2007 and the HCEI by: (1) the greening of existing assets, (2) the expansion of renewable energy generation and (3) the acceleration of energy efficiency and load management programs. Major initiatives are being pursued in each category.

In May 2010, HECO reported achieving a consolidated RPS of 19% in 2009. This was accomplished through a combination of municipal solid waste, geothermal, wind, biomass, hydro, photovoltaic and biodiesel renewable generation resources; renewable energy displacement technologies; and energy savings from efficiency technologies. HECO noted that DSM programs contributed significantly to achieving the 19% RPS level, and

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indicated that, without including the energy savings, the RPS would have been 9.2% instead of 19%. Under current RPS law, energy savings resulting from energy efficiency programs will not count toward the RPS from January 1, 2015.

The electric utilities are actively exploring the use of biofuels for existing and planned company-owned generating units. HECO has committed to using nearly 100% biofuels for its new 110 MW generating unit. HECO is also researching the possibility of switching its steam generating units from fossil fuels to biofuels, and in the Energy Agreement has committed to do so if economically and technically feasible and if adequate biofuels are available. HECO is also studying potential investments in fuel-related infrastructure to support the handling of biofuels. In June 2010, the PUC approved HECO and MECO s biodiesel fuel supply contracts for their respective biodiesel demonstration projects, the inclusion of the costs under such contracts in their ECACs and, in the case of HECO, the commitment of funds (estimated at $5.2 million) for the purchase of capital equipment. Also in June 2010, the PUC approved a two-year biodiesel supply contract with Renewable Energy Group Marketing and Logistics, LLC (REG) primarily for CIP CT-1. In July 2010, the PUC approved the purchase of 400,000 gallons of biodiesel to be used for operational testing and to collect emissions data for CIP CT-1.

In March 2010, HECO and its subsidiaries issued a request for proposal (RFP) for biofuels produced from feedstocks grown in, made in, or otherwise originating in Hawaii (local biofuel) to potentially supply multiple locations, including the site of CIP CT-1 (after the expiration of the REG contract). Bids were received and are under evaluation. HECO expects to issue additional fuel RFPs in 2011, including an RFP for fuel for CIP CT-1 upon the expiration of the REG contract. Under current RPS law, biofuel use in existing and new generating units counts toward the RPS.

The electric utilities also support renewable energy through the negotiation and execution of PPAs with non-utility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric, photovoltaic and wind turbine generating systems).

On April 30, 2009, HECO filed an application with the PUC for approval of a Photovoltaic (PV) Host Pilot Program, which would be a two-year pilot program whereby HECO, HELCO and MECO would lease rooftops or other space from property owners, with a focus on governmental facilities, for the installation of third-party owned photovoltaic systems. The PV developer would own, operate and maintain the system and sell the energy to the utilities at a fixed rate under a long-term contract. On August 31, 2010, HECO proposed several modifications to the pilot program, including deferment of HELCO s and MECO s participation in the program and utilization of select PV Host projects on Oahu as test platforms to evaluate grid integration technologies (as well as to help address grid integration issues associated with existing and growing penetration levels of distributed intermittent generation).

In June 2008, the PUC approved HECO s Oahu Renewable Energy Request for Proposals (RFP) for combined renewable energy projects up to 100 MW and HECO issued the RFP shortly thereafter. HECO is currently negotiating PPAs with the bidders in the Award Group.

Included in the bids received in response to the RFP were proposals for two large scale neighbor island wind projects that would produce energy to be imported to Oahu via a yet-to-be-built undersea transmission cable system. In accordance with the Energy Agreement, the proposals for two large scale neighbor island wind projects (Big Wind projects) were bifurcated from the Oahu Renewable Energy RFP for separate negotiation. Subsequently, HECO requested a waiver from the competitive bidding framework for the two non-conforming proposals and a PUC decision is pending.

On September 30, 2010, the PUC approved the electric utilities proposed Electric Vehicle (EV) Charging Time of Use Pilot Rates, which are now available to 1,000 HECO, 300 HELCO and 300 MECO customers for charging highway-capable, four-wheeled EVs. The EV Pilot Rates will remain in effect for three years and are designed to encourage early adoption of EVs and incentivize customers to charge EVs during off-peak times of the day.

The electric utilities promote research and development in the areas supporting renewable energy such as biofuels, ocean energy, battery storage, smart grids and integration of non-firm power into the separate island electric grids. The utilities are evaluating several potential energy storage and smart grid demonstration projects, and conducting various integration studies.

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Competition. 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 independent power producers (IPPs) and customer self-generation, with or without cogeneration.

Competitive bidding proceeding. In December 2006, the PUC issued a decision that included a final competitive bidding framework, which became effective immediately. The final framework states, among other things, that under the framework: (1) a utility is required to use competitive bidding to acquire a future generation resource or a block of generation resources unless the PUC finds bidding to be unsuitable; (2) the framework does not apply in certain situations identified in the framework; (3) waivers from competitive bidding for certain circumstances will be considered; (4) the utility is required to select an independent observer from a list approved by the PUC whenever the utility or its affiliate seeks to advance a project proposal (i.e., in competition with those offered by bidders); (5) the utility may consider its own self-bid proposals in response to generation needs identified in its RFP; and (6) for any resource to which competitive bidding does not apply (due to waiver or exemption), the utility retains its traditional obligation to offer to purchase capacity and energy from a Qualifying Facility (QF) at avoided cost upon reasonable terms and conditions approved by the PUC.

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

The utilities received approval for waivers from the competitive framework to negotiate modifications to existing PPAs that generate electricity from renewable resources. Also, certain renewable energy projects were grandfathered from the competitive bidding process. Of the grandfathered projects, the PUC has approved the PPA with Kahuku Wind Power, the PUC is considering the PPA with Honua Power, and HECO continues to negotiate with OTEC International.

Distributed generation (DG) proceeding. In January 2006, the PUC issued a D&O indicating that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, DG that is economical and reliable has an opportunity to come to fruition and DG that is not cost-effective does not enter the system. The D&O affirmed the ability of the 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. The PUC found that the disadvantages outweigh the advantages of allowing a utility to provide DG services on a customer s site. 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 utilities from providing DG services at this early stage of DG market development. Therefore, the D&O allows the utility to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need, (2) the DG is the lowest cost alternative to meet that need and (3) it can be shown that, in an open and competitive process acceptable to the PUC, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility s offering.

In April 2006, the PUC provided clarification to the conditions under which the utilities are allowed to provide regulated DG services (e.g., the utilities can use a portfolio perspective a DG project aggregated with other DG systems and other supply-side and demand-side options to support a finding that utility-owned customer-sited DG projects fulfill a legitimate system need, and the economic standard of least cost in the order means lowest reasonable cost consistent with the standard in the integrated resource plan (IRP) framework).

In September 2008, HECO executed an agreement with the State of Hawaii Department of Transportation to develop a dispatchable standby generation (DSG) facility at the Honolulu International Airport that will be owned by the State and operated by HECO. The agreement has been approved by the PUC, which also waived the project from the Competitive Bidding Framework. The DSG facility is projected to be in operation

in April 2012.

HECO is also evaluating the potential to develop utility-owned DG at Oahu military bases in order to meet utility system needs and the energy objectives of the federal Department of Defense (DOD).

In February 2008, the PUC approved a MECO agreement for the installation of a CHP system at a hotel site on the island of Lanai. The CHP system was placed in service in September 2009.

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DG tariff proceeding. In 2008, the PUC approved modifications to the utilities interconnection tariffs and a standby service tariff. In January 2010, the utilities requested modifications of the DG interconnection tariff. In May 2010, the PUC approved certain modifications that had been stipulated to by the parties, including (1) modifying requirements for conducting detailed interconnection studies; (2) establishing a standard three-party interconnection agreement; (3) including cross-limitation of liability and non-indemnification language with respect to projects where a State of Hawaii agency is the customer; and (4) requiring additional information regarding the customer s generating facility. The remaining issues continue to be evaluated in the proceeding. Final statements of position are due in December 2010.

DG and distributed energy storage under the Energy Agreement. Under the Energy Agreement, the utilities committed to facilitate planning for distributed energy resources through a new Clean Energy Scenario Planning process. Under this process, Locational Value Maps were developed in 2009 to identify areas where DG and distributed energy storage would provide utility system benefits and can be reasonably accommodated.

The utilities also agreed to power utility-owned DG using sustainable biofuels or other renewable technologies and fuels, and to support either customer-owned or utility-owned distributed energy storage.

The parties to the Energy Agreement support reconsideration of the PUC s restrictions on utility-owned DG where it is proven that utility ownership and dispatch clearly benefits grid reliability and ratepayer interests, and the equipment is competitively procured. The parties also support HECO s dispatchable standby generation units upon showing reasonable ratepayer benefits.

The utilities may contract with third parties to aggregate fleets of DG or standby generators for utility dispatch or under PPAs, or may undertake such aggregation themselves if no third parties respond to a solicitation for such services.

The Energy Agreement also provides that to the degree that transmission and distribution automation and other smart grid technology investments are needed to facilitate distributed energy resource utilization, those investments should be recoverable through a Clean Energy Infrastructure Surcharge (which was replaced by the Renewable Energy Infrastructure Program (REIP) Surcharge) and later placed in rate base in the next rate case proceeding.

Most recent rate requests. The electric utilities initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. The PUC may grant an interim increase within 10 to 11 months following the filing of an application, but there is no guarantee of such an interim increase and interim amounts collected are refundable, with interest, to the extent they exceed the amount approved in the PUC s final D&O. The timing and amount of any final increase is determined at the discretion of the PUC. The adoption of revenue, expense, rate base and cost of capital amounts (including the return on average common equity (ROACE) and return on rate base (ROR)) for purposes of an interim rate increase does not commit the PUC to accept any such amounts in its final D&O.

ROACEs of 10.7% were found to be reasonable by the PUC in the most recent final rate decisions issued in September 2010, October 2010 and July 2010 in HECO, HELCO and MECO rate cases based on 2007, 2006 and 2007 test years, respectively. The ROACEs used by the PUC for purposes of the most recent interim rate increases issued in August 2009 and July 2010 in HECO and MECO rate cases based on 2009 and 2010 test years, respectively, were both 10.5%, and these ROACEs have not been reduced to reflect the implementation of decoupling. The settlement

agreement between HELCO and the Consumer Advocate for HELCO s 2010 test year rate case, which is subject to PUC approval, includes a 10.125% ROACE that reflects the implementation of decoupling (see HELCO 2010 test year rate case below).

For the 12 months ended September 30, 2010, the actual ROACEs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates) for HECO, HELCO and MECO were 7.32%, 7.25% and 4.10%, respectively. The utilities actual ROACEs were lower than their final and interim D&O ROACEs primarily due to lower KWH sales than the sales used to determine the interim rates and increased O&M expenses.

The RORs found to be reasonable by the PUC in the most recent final rate decisions were 8.62% for HECO, 8.33% for HELCO and 8.67% for MECO (final D&Os noted above). The RORs used by the PUC for purposes of the

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most recent interim increases were 8.45% for HECO and 8.43% for MECO (interim D&Os noted above). For the 12 months ended September 30, 2010, the actual RORs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates) for HECO, HELCO and MECO were 6.58%, 6.59% and 4.99%, respectively.

In the most recent interim rate decisions, the PUC allowed the use by each utility of pension and postretirement benefits other than pensions (OPEB) tracking mechanisms (with varied treatment of the pension assets of each utility) and allowed the continuation of each utility s ECAC. The pension and OPEB tracking mechanisms are reflected in test year estimates for HELCO and MECO s 2010 test year and HECO s 2011 test year rate case applications. In HECO s and MECO s 2007 and HELCO s 2006 test year rate case final D&Os, the PUC approved their pension and OPEB tracking mechanisms. For a description of the utilities pension and OPEB tracking mechanisms, see Balance sheet recognition of the funded status of retirement plans in Note 10 of HECO s Notes to Consolidated Financial Statements incorporated by reference in HEI s Form 10-K for the year ended December 31, 2009. For a description of the utilities ECACs, see below.

For a discussion of HECO s 2009 test year rate case and the interim increase granted, see Most recent rate requests in Management s Discussion and Analysis of Financial Condition and Results of Operations in HECO s Form 10-Q for the quarter ended March 31, 2010.

HECO.

2007 test year rate case. On December 22, 2006, HECO filed a request for a general rate increase of $99.6 million, or 7.1% over the electric rates then in effect, based on a 2007 test year, an 11.25% ROACE and an 8.92% ROR on a $1.214 billion average rate base. HECO s application included a proposed new tiered rate structure for residential customers to reward customers who practice energy conservation with lower electric rates for lower monthly usage.

On September 6, 2007, HECO, the Consumer Advocate and the DOD (collectively, the parties) executed and filed an agreement on most of the issues in this rate case, and on October 22, 2007, the PUC issued, and HECO implemented, an interim D&O granting HECO an increase of $70 million in annual revenues over rates effective at the time of the interim D&O, subject to refund with interest. The interim increase was based on the settlement agreement which included, as a negotiated compromise of the parties respective positions, an ROACE of 10.7%, an 8.62% ROR, a $1.158 billion average rate base and a capital structure which includes a 55.1% common equity capitalization. In May 2008, the interim increase was adjusted from $70 million to $77.9 million in annual revenues to take into account the changes in current effective rates as a result of the final D&O in the 2005 test year rate case. In September 2008, the interim increase was corrected to $77.5 million based on a filing submitted by HECO.

On September 14, 2010, the PUC issued a final D&O that confirmed the interim increase of $77.5 million, approved the pension and postretirement benefits other than pension tracking mechanisms (which had been approved on an interim basis), confirmed that HECO s ECAC complies with Act 162 and approved the stipulated rate design, which includes the new tiered rate structure for residential customers. Decoupling was not addressed in this proceeding and the final D&O did not address the implementation of decoupling.

2011 test year rate case. On July 30, 2010, HECO filed a request with the PUC for a general rate increase of $94 million, or 5.4% over the electric rates currently in effect, based on a 2011 test year, the estimated impacts of the implementation of decoupling as proposed in the PUC s separate decoupling docket and depreciation rates and methods as proposed by HECO in a separate depreciation proceeding. Excluding the

effects of the implementation of decoupling, the effective revenue request is $113.5 million, or 6.6%. The request includes an increase of $54 million, or 3.1% (or $74 million, or 4.3% without the implementation of decoupling), primarily to pay for major capital projects and operating and maintenance costs to maintain service reliability. The remainder of the request is to recover the costs for several proposed programs to help reduce Hawaii s dependence on imported oil, further increase reliability and increase fuel security.

The request is based on a 10.75% return on average common equity (ROACE), an 8.54% return on rate base (ROR), a $1.57 billion average rate base and a capital structure which includes a 56% common equity capitalization. HECO s electric rates currently in effect include an annual final rate increase of $77.5 million granted by the PUC in HECO s 2007 test year rate case and an annual interim rate increase of $73.8 million granted by the

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PUC in HECO s 2009 test year rate case. The interim rate increase is subject to a final decision from the PUC, and subject to refund with interest if and to the extent that the final decision provides for a lesser increase.

The proposed rate increase would recover investments in capital projects completed or to be completed since the 2009 test year rate case (e.g., higher depreciation expense), including investments in the 110 MW biofuel generating facility that were not part of the 2009 test year rate case and Phase 1 of the East Oahu Transmission Project (which was placed in service on June 29, 2010); increased costs to support the integration of more renewable energy generation; other capital improvements; and higher operation and maintenance costs required to maintain and improve system reliability.

HELCO.

2006 test year rate case. In May 2006, HELCO filed a request for a general rate increase of $29.9 million, or 9.24% over the electric rates then in effect, based on a 2006 test year, an 8.65% ROR, an 11.25% ROACE and a $369 million average rate base. HELCO s application included a proposed new tiered rate structure, which was 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), and increased O&M expenses.

In March 2007, HELCO and the Consumer Advocate reached settlement agreements on all revenue requirement issues in the rate case proceeding. HELCO agreed to write off a portion of CT-4 and CT-5 costs, which resulted in an after-tax charge of approximately $7 million in the first quarter of 2007.

On April 4, 2007, the PUC issued an interim D&O granting HELCO an increase of 7.58%, or $24.6 million in annual revenues, over revenues at present rates. The interim increase reflected the settlement of the revenue requirement issues reached between HELCO and the Consumer Advocate and was based on an average rate base of $357 million (which reflects the write-off of a portion of CT-4 and CT-5 costs) and an ROR of 8.33% (incorporating an ROACE of 10.7%). On May 15, 2007, HELCO and the Consumer Advocate filed a settlement letter that reflected their agreement on the remaining rate design issues in the proceeding.

On October 28, 2010, the PUC issued a final D&O that confirmed the interim increase of $24.6 million, approved the pension and postretirement benefits other than pension tracking mechanisms (which had been approved on an interim basis), confirmed that HELCO s ECAC complies with Act 162, and approved the stipulated rate design, which includes the new tiered rate structure. Decoupling was not addressed in this proceeding and the final D&O did not address the implementation of decoupling.

2010 test year rate case. On December 9, 2009, HELCO filed a request for a general rate increase of $20.9 million, or 6.0% over the electric rates then in effect, based on a 2010 test year, a 10.75% ROACE and an 8.73% ROR on a $487 million rate base. The proposed rate increase would cover investments for system upgrade projects, including an 18 MW heat recovery steam generator (ST-7) and two major transmission line upgrades, as well as increasing O&M expenses. HELCO s proposed ROR and ROACE assume (1) the establishment of an RBA and a revenue adjustment mechanism, based on the Joint Decoupling Proposal (see Decoupling Proceeding below), (2) the implementation of the REIP/CEIS, which the PUC has approved in a separate proceeding, and (3) a purchased power adjustment clause to recover non-energy PPA

costs proposed in the proceeding. If the proposals are not approved, the test year revenue requirements would be $22.1 million, based on an 8.87% ROR and an 11.0% ROACE.

HELCO s filing also proposes adoption of inverted tiered rates and an optional residential time-of-use service rate to enable customers to manage their energy usage.

HELCO and the Consumer Advocate executed and filed a settlement agreement on all material issues in this rate case proceeding on September 16, 2010, and filed a Joint Statement of Probable Entitlement on October 5, 2010, which are subject to approval by the PUC. If the PUC does not accept the material terms of the settlement agreement, either or both of the parties may withdraw from the agreement and pursue their respective positions in the proceeding without prejudice. If the settlement is approved by the PUC, the net interim increase in annual

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revenues would amount to $4.4 million, or a 1.2% increase. As part of the settlement agreement, HELCO would reset the heat rate used in its ECAC calculation when the interim rates become effective, which would shift $13.9 million of revenues that would have been included in the ECAC revenues to the interim increase and result in a total interim increase of $18.3 million. The agreement included a 10.125% ROACE, an 8.38% ROR, a $465 million average rate base and a capital structure which includes 56% of common equity. In the settlement agreement, the parties agree that the negotiated ROACE and ROR reflect the implementation of decoupling and other recovery mechanisms when interim rates go into effect. The interim increase also reflects the new depreciation rates and methods proposed by HELCO and approved by the PUC on a temporary basis in a separate depreciation proceeding.

The difference between the amount requested in the initial application and the $4.4 million net increase under the settlement relates primarily to changes in expenses since the rate case was filed and changes in the ROACE and ROR.

Management cannot predict the timing, or the ultimate outcome, of an interim or final D&O in this rate case.

MECO.

2010 test year rate case. On September 30, 2009, MECO filed a request for a general rate increase of $28.2 million, or 9.7% over the electric rates then in effect, based on a 2010 test year, a 10.75% ROACE and an 8.57% ROR on a $390 million rate base. The proposed rate increase would cover investments to improve service reliability, including the replacement and upgrade of power plant control systems, installation of a new 150-kW photovoltaic system, replacement and upgrade of underground lines, new or expanded substations to support growth and improve service, and higher O&M expenses due to MECO s aging infrastructure. MECO s proposed ROR and ROACE assume the establishment of an RBA and a revenue adjustment mechanism, based on the Joint Decoupling Proposal. If the Joint Decoupling Proposal is not approved, the test year revenue requirements would be recalculated using an 11% ROACE and an 8.72% ROR.

On June 21, 2010, MECO and the Consumer Advocate executed and filed a settlement agreement on all material issues in this rate case proceeding, which agreement is subject to approval by the PUC. On July 27, 2010, the PUC issued an interim D&O granting MECO an increase of $10.3 million in annual revenues, or 3.3% over revenues currently in effect. The tariff changes implementing the interim increase became effective on August 1, 2010. The interim increase is based on the settlement agreement, which included a 10.5% ROACE, an 8.43% ROR, a $387 million average rate base and a capital structure which includes 56.9% of common equity. The interim increase also reflects the new depreciation rates and methods proposed by MECO and approved by the PUC on a temporary basis in a separate depreciation proceeding, but does not reflect the implementation of decoupling.

Under the settlement agreement, MECO agreed to limit to $3.5 million the investment in plant for a CHP system installed at a hotel site in September 2009. The actual cost was $4.8 million, and the amount approved by the PUC in February 2008 was $2.1 million. As a result, in the second quarter of 2010, MECO charged to expense approximately $1.3 million of its investment in the CHP system.

Management cannot predict the timing, or the ultimate outcome, of a final D&O in this rate case.

Decoupling proceeding. In the Energy Agreement, the parties agreed to seek approval from the PUC to implement, beginning with the HECO 2009 test-year rate case interim decision, a decoupling mechanism, similar to that in place for several California utilities, which decouples revenues from KWH sales and provides revenue adjustments (increases/decreases) for the differences (shortages/overages) between the amount determined in the last rate case and (a) the current cost of operating the utility as deemed reasonable and approved by the PUC, (b) the return on and return of ongoing capital investment (excluding projects included in a proposed new CEIS), and (c) changes in tax expense due to changes in State or Federal tax rates. The decoupling mechanism would be subject to review at any time by the PUC or upon request of any utility or the Consumer Advocate.

In October 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In May 2009, the utilities and the Consumer Advocate filed their joint proposal (Joint Decoupling Proposal) for a decoupling mechanism with three components: (1) a sales decoupling component via a

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revenue balancing account (RBA), (2) a revenue escalation component via a revenue adjustment mechanism and (3) an earnings sharing mechanism.

In February 2010, the PUC approved the Joint Decoupling Proposal (with subsequent modifications to the proposal agreed to by the utilities and the Consumer Advocate), subject to the issuance of a final D&O, and ordered the utilities and the Consumer Advocate to jointly submit for the PUC s consideration a proposed Final D&O, which they did on March 23, 2010.

On August 31, 2010, the PUC issued a Final D&O, which approved the decoupling mechanism proposed in the Joint Decoupling Proposal, subject to certain modifications. Those modifications excluded merit wage increases from the revenue adjustment mechanism, required additional information related to Baseline Capital Projects, and required the utilities and the Consumer Advocate to jointly file an outreach plan. Implementation of sales decoupling is to occur when rates that reflect a reduced rate of return due to decoupling are approved by the PUC in either an interim or final D&O in the utilities pending rate cases.

In the Settlement Letter filed in the HELCO 2010 test year rate case, HELCO resubmitted three of its tariffs to reflect the provisions of the Decoupling Final D&O. To enable the implementation of decoupling upon issuance of the interim D&O for this rate case, the Consumer Advocate and HELCO agreed to a ROACE for interim relief purposes that assumes the implementation of the decoupling mechanism, the Renewable Energy Infrastructure Program surcharge, and the Purchased Power Adjustment Clause, and agreed to accept the PUC s decision on the final ROACE authorized in HECO s 2009 test year rate case as the final ROACE for HELCO s 2010 test year rate case. Management cannot predict the timing, or the ultimate outcome, of an interim or final D&O in this proceeding.

Energy Cost Adjustment Clauses (ECACs). The rate schedules of the electric utilities include ECACs under which electric rates are adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power.

The HECO (2009 and 2011 test years), HELCO (2006 and 2010 test years) and MECO (2010 test year) rate increase applications requested the continuation of their ECACs in their present forms. In the final D&Os for the MECO and HECO 2007 test year rate cases, the PUC found that MECO s and HECO s ECACs comply with Act 162 and should be implemented as agreed by the parties to the respective rate case proceedings.

Other regulatory matters. In addition to the items below, also see Hawaii Clean Energy Initiative and Major projects in Note 5 of HECO s Notes to Consolidated Financial Statements for a number of actions committed to in the Energy Agreement that will require PUC approval.

Demand-side management programs.

Energy Efficiency (EE) DSM Programs. In February 2007, the PUC required that the administration of all EE DSM programs be turned over to a non-utility, third-party administrator. The PUC executed a public benefits fund (PBF) administrator contract with Science Applications International Corporation (SAIC) and on July 1, 2009, SAIC began administering the EE DSM programs. A PBF surcharge on electric utility revenues (1% in 2010, 1.5% in 2011 and 2012 and 2% thereafter) is being used to fund EE DSM programs, incentives, program administration,

and other related program costs, as expended by SAIC for the programs or by program contractors.

The EE DSM Docket D&O also provided for HECO s recovery of DSM program costs and utility incentives. With respect to cost recovery, the PUC continues to permit recovery of reasonably-incurred DSM implementation costs, under the IRP framework. On June 29, 2009, HECO filed with the PUC a request to increase its residential DSM programs budget by a net $1.4 million (an estimated $2.5 million overrun in certain programs offset by an estimated $1.1 million underrun in other programs) primarily to pay customer incentives related to DSM program applications completed and approved through June 30, 2009. In June 2009, HECO accrued and expensed the net $1.4 million of incentives. HECO is awaiting a determination from the PUC on its request to increase its program budget. In its DSM surcharge filing with the PUC on March 31, 2010, HECO calculated revised DSM surcharge levels effective April 1, 2010, but since HECO s June 29, 2009 budget increase request was pending at the PUC, HECO did not include in the revised DSM surcharge levels $2.3 million in DSM program expenditures that were in excess of PUC approved program budgets.

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DSM utility incentives are derived from a graduated performance-based schedule of net system benefits. In order to qualify for an incentive, the utility must meet cumulative MW and MWh reduction goals for its EE DSM programs in the commercial, industrial and residential sectors. The amount of the annual incentive has been subject to caps determined separately for each utility.

HECO and MECO earned their maximum DSM utility incentives of $4 million and $0.3 million, respectively, in 2008. HECO earned $0.7 million in DSM utility incentives in 2009, however, in its DSM surcharge filing with the PUC on March 31, 2010, HECO s revised DSM surcharge levels did not include recovery of the $0.7 million in incentives pending the PUC s review of the calculation.

Load Management DSM Programs. Unlike the EE DSM programs, load management DSM programs continue to be administered by the utilities. HECO s 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 or central air conditioning systems 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. This program includes small business direct load control and voluntary program elements.

In December 2009, the PUC approved HECO s requests to extend the Commercial and Industrial Direct Load Control (CIDLC) Program and the Residential Direct Load Control (RDLC) Program through 2012. The CIDLC Program application included an action plan for a load aggregator pilot program. In October 2010, HECO filed an RDLC program increase request to accommodate anticipated base expenses for the cost of a program impact evaluation needed to update the cost-effectiveness calculations identified by the PUC.

In April 2008, HECO filed an application for approval of a Dynamic Pricing Pilot (DPP) Program that allows prices to change from normal tariff rates as system conditions change and encourages customer curtailment of load through price incentives when there is insufficient generation to meet a projected peak demand period. In September 2010, HECO withdrew the DPP Program application due in part to the uncertain deployment schedule for smart meters in the utilities service territories.

In August 2010, HECO filed an application for a Fast Demand Response Pilot (Fast DR) Program a two-year pilot program designed to test commercial and industrial market acceptance of load reductions within 10-minutes of event notification, and demonstrate the technical aspects of semi-automatic and automatic mechanisms to initiate customer reductions in load.

*Clean energy scenario planning and integrated resource planning***.** The PUC issued an order in 1992 requiring the energy utilities in Hawaii to develop IRPs, which would then be approved, rejected or modified by the PUC. The goal of integrated resource planning is the identification of demand- and supply-side resources and the integration of these resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. The utilities latest IRPs are described in Management s Discussion and Analysis of Financial Condition and Results of Operations incorporated by reference in HEI s Form 10-K for the year ended December 31, 2009.

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

recover IRP costs (which are included in O&M) through base rates. Also, see Demand-side management programs above.

The parties to the Energy Agreement agreed to seek to replace the IRP process with a new Clean Energy Scenario Planning (CESP) process intended to be used to determine future investments in generation and transmission that will be necessary to facilitate high levels of renewable energy production and reductions in electricity use through energy efficiency programs. In the fourth quarter of 2008, the PUC closed the IRP-4 processes and directed the utilities to suspend all activities pursuant to the IRP framework to allow for resources to be diverted to the development of the CESP framework.

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HECO and the Consumer Advocate filed a proposed CESP framework with the PUC in April 2009. In May 2009, the PUC opened an investigative proceeding to examine the proposed framework. As consensus between all parties and participants in the proceeding could not be reached, four revised proposed frameworks were separately filed in August 2010 for the PUC s consideration. The CESP framework filed jointly by HECO and its subsidiaries, the Consumer Advocate, Kauai Island Utility Cooperative and the County of Kauai proposes a planning process resulting in a 5-year Action Plan developed from multiple scenarios and associated 20-year resource plans for each scenario. The proposed focus on scenario planning and shorter-term action plans (rather than 20-year plans) recognizes that planning assumptions are uncertain and that the planning framework should facilitate making adjustments to resource plans as circumstances change. PUC adoption of a CESP framework is pending.

Adequacy of supply (AOS).

HECO. HECO s 2010 AOS letter, filed in February 2010, indicated that based on the December 2009 update to its sales and peak forecast and on the full availability of CIP CT-1, HECO estimates it would have a reserve capacity surplus of approximately 30 MW in 2010 and that its generation capacity for years 2010 to 2014 will be sufficient to meet reasonably expected demands for service and provide reasonable reserves for emergencies.

HELCO. HELCO s 2010 AOS letter filed in January 2010 indicated that HELCO s generation capacity for the period 2010 to 2012 is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies. HELCO is currently negotiating with two IPPs to supply additional firm renewable generating capacity to the HELCO grid. Should these additional firm renewable facilities come on line within the next three years as anticipated, HELCO will not have a need for additional firm capacity in the foreseeable future. HELCO, however, may choose to add additional renewable generating capacity to replace existing nonrenewable generation.

MECO. MECO s 2010 AOS letter filed in January 2010 indicated that MECO s generation capacity for the period 2010 to 2012 was sufficient to meet the forecasted demands on the islands of Maui, Lanai and Molokai and that the estimated need date for additional firm capacity on Maui was 2021. Subsequently, MECO s June 2010 sales and peak forecast reflected higher future peaks than its previous forecast. In June 2010, MECO filed an update to its 2010 AOS letter for Maui based on its analysis of the new forecast. MECO s update indicated that Maui s generation capacity for the period 2011 to 2014 is sufficient to meet the forecasted demands and that the estimated need date for additional firm capacity on Maui is moved up to 2015.

December 2008 outage. On December 26, 2008, an island-wide outage occurred on the island of Oahu that resulted in a loss of electric service to HECO customers ranging from approximately 7 to 20 hours. On January 12, 2009, the PUC initiated an investigation of the outage.

In March 2009, HECO submitted an outage report prepared by its expert consultant, POWER. The outage report concluded that the island-wide outage was triggered by lightning strikes on or near HECO s transmission system. POWER found that: (1) the HECO system was in proper operating condition and was appropriately staffed at the time of the lightning storm, and (2) HECO s restoration efforts were prudent and allowed for restoration of power as quickly as possible under the circumstances.

In January 2010, the Consumer Advocate submitted its Statement of Position that HECO could not have anticipated or prevented the outage through reasonable measures and could not have reasonably shortened the outage and restored power more quickly to customers. The Consumer

Advocate further stated that penalties should not be assessed for the outage, but recommended that numerous studies be performed with the objective of preventing or minimizing the scope and duration of future power outages.

Management cannot at this time predict the outcome of the PUC s investigation of the 2008 outage or its impact on HECO.

Collective bargaining agreements. See Collective bargaining agreements in Note 5 of HECO s Notes to Consolidated Financial Statements.

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Legislation and regulation. Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. See, for example, Hawaii Clean Energy Initiative and Environmental regulation in Note 5 of HECO s Notes to Consolidated Financial Statements.

Increase in oil tax. On July 1, 2010, the state tax on petroleum products shipped to Hawaii increased from $0.05 to $1.05 per barrel. The higher tax, which is passed on to consumers, increased the price of gasoline and electricity and is expected to generate funds to reduce the state s budget deficit and finance food and renewable energy programs.

Other developments.

Advanced Metering Infrastructure (AMI). In December 2008, the utilities filed an AMI project application with the PUC for approval to implement an AMI project, covering approximately 451,000 meters (65% on Oahu, 20% on the island of Hawaii and 15% on Maui). The AMI project application included a request to approve a contract between Sensus Metering Systems, Inc. (Sensus) and HECO under which the utilities would purchase smart meters and pay Sensus to provide and maintain a radio frequency communication system to operate the smart meters and related equipment.

HECO submitted a proposal to the PUC in May 2010, describing an extended pilot test of the AMI system and smart meters involving 5,000 new Sensus AMI meters. HECO s proposal also contained an update on developments in the Smart Grid, CIS and cyber-security areas.

On July 26, 2010, the PUC issued an Order denying HECO, HELCO and MECO s requests for an extended pilot test of their AMI system and smart meters on Oahu, and dismissing the utilities AMI application, without prejudice. In its Order, the PUC reiterated its support for an AMI and smart grid concept to reduce the state s dependence on fossil fuels, but noted that future AMI and smart grid applications should include or be preceded by an overall smart grid plan or proposal filed with the PUC.

As of September 30, 2010, the utilities did not have any deferred costs related to the AMI project proceeding. Management is currently evaluating the PUC s Order and the future plans for AMI. HECO and Sensus have agreed that their respective rights to terminate their contract (based on the lack of PUC application approval) shall extend until March 31, 2011.

Commitments and contingencies. See Note 5 of HECO s Notes to Consolidated Financial Statements.

Recent accounting pronouncements and interpretations. See Note 7 of HECO s Notes to Consolidated Financial Statements.

FINANCIAL CONDITION

Liquidity and capital resources. Management believes that HECO s ability, and that of its subsidiaries, to generate cash, both internally from operations and externally from issuances of equity and debt securities, commercial paper and lines of credit, is adequate to maintain sufficient liquidity to fund their respective capital expenditures and investments and to cover debt, retirement benefits and other cash requirements in the foreseeable future.

HECO s consolidated capital structure was as follows as of the dates indicated:

(dollars in millions)	September 30, 2010		December 31, 2009	
Short-term borrowings	$	%	$	%
Long-term debt, net	1,058	44	1,058	44
Preferred stock	34	1	34	1
Common stock equity	1,326	55	1,306	55
	$ 2,418	100%	$ 2,398	100%

HECO utilizes short-term debt, typically commercial paper, to support normal operations, to refinance short-term debt and for other temporary requirements. HECO also borrows short-term from HEI for itself and on behalf of HELCO and MECO, and HECO may borrow from or loan to HELCO and MECO short-term. The intercompany borrowings among the utilities, but not the borrowings from HEI, are eliminated in the consolidation of HECO s financial statements. HECO and its subsidiaries periodically utilize long-term debt, historically borrowings of the

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proceeds of special purpose bonds issued by the State of Hawaii Department of Budget and Finance (DBF), to finance the utilities capital improvement projects, or to repay short-term borrowings used to finance such projects. The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO.

Due to market conditions since September 2008 which resulted in a tightening of the commercial paper market, higher commercial paper rates and limitations on maturity options as well as a result of an S&P downgrade of HECO s short-term borrowing rating to A-3 from A-2, HECO drew on its previous $175 million syndicated line of credit facility in June and July 2009, rather than issue commercial paper. All such draws/borrowings were repaid in August 2009. HECO re-entered the commercial paper market in March 2010, experiencing higher rates and shorter terms.

Effective May 7, 2010, HECO entered into a revolving unsecured credit agreement establishing a line of credit facility of $175 million, with a letter of credit sub-facility, with a syndicate of eight financial institutions. See Note 9 of HECO s Notes to Consolidated Financial Statements.

The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HECO s Issuer Rating (e.g., from BBB+/Baa1 to BBB/Baa2 by S&P and Moody s, respectively) would result in a commitment fee increase of 10 basis points and an interest rate increase of 25 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB+/Baa1 to A-/A3 by S&P or Moody s, respectively) would result in a commitment fee decrease of 5 basis points and an interest rate decrease of 25 basis points on any drawn amounts. The agreement contains customary conditions that must be met in order to draw on it, including compliance with several covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HECO, and restricting its ability as well as the ability of any of its subsidiaries to guarantee additional indebtedness of the subsidiaries if such additional debt would cause the subsidiary s Consolidated Subsidiary Funded Debt to Capitalization Ratio to exceed 65% (ratio of 46% for HELCO and 43% for MECO as of September 30, 2010, as calculated under the agreement)). In addition to customary defaults, HECO s failure to maintain its financial ratios, as defined in its agreement, or meet other requirements may result in an event of default. For example, under its agreement, it is an event of default if HECO fails to maintain a Consolidated Capitalization Ratio (equity) of at least 35% (ratio of 55% as of September 30, 2010, as calculated under the agreement).

HECO s short-term borrowings (other than from MECO), HECO s line of credit facilities and the principal amount of special purpose revenue bonds that have been authorized by the Hawaii legislature for future issuance by the DBF for the benefit of the utilities were as follows for the period and as of the dates indicated:

	Nine months ended September 30, 2010	Balance	
(in millions)	**Average balance**	**September 30, 2010**	**December 31, 2009**
Short-term borrowings(1)			
Commercial paper	$ 5	$	$
Line of credit draws			
Borrowings from HEI			
Line of credit facilities			
Undrawn capacity under line of credit facility expiring May 6, 2011	N/A	175	175
Special purpose revenue bonds authorized for issue			
2007 legislative authorization (expiring June 30, 2012)			
HECO		170	170

HELCO		55		55
MECO		25		25
Total special purpose revenue bonds available for issue	$	250	$	250

(1) At October 29, 2010, HECO had no outstanding commercial paper, its line of credit facility was undrawn, and it had no borrowings from HEI.

At September 30, 2010, HECO had $20 million of short-term borrowings from MECO and HELCO had $7 million of short-term borrowings from HECO.

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Management believes that, if HECO s commercial paper ratings were to be further downgraded or if credit markets were to further tighten, it would be even more difficult and expensive to sell commercial paper or secure other short-term borrowings. Similarly, management believes that if HECO s long-term credit ratings were to be downgraded, or if credit markets further tighten, it could be even more difficult and/or expensive for DBF and/or the Company to sell special purpose revenue bonds and other debt securities, respectively, for the benefit of the utilities in the future. Such limitations and/or increased costs could materially adversely affect the results of operations and financial condition of HECO and its subsidiaries.

As of October 29, 2010, the S&P and Moody s ratings of HECO securities were as follows:

	S&P	Moody s
Commercial paper	A-3	P-2
Special purpose revenue bonds-insured (principal amount noted in parentheses, senior unsecured, insured as follows):		
Ambac Assurance Corporation ($0.2 billion)	BBB*	Baa1*
Financial Guaranty Insurance Company ($0.3 billion)	BBB*	Baa1*
MBIA Insurance Corporation ($0.3 billion)	A**	Baa1**
Syncora Guarantee Inc. (formerly XL Capital Assurance Inc.) ($0.1 billion)	BBB*	Baa1*
Special purpose revenue bonds uninsured ($150 million)	BBB	Baa1
HECO-obligated preferred securities of trust subsidiary	BB+	Baa2
Cumulative preferred stock (selected series)	Not rated	Baa3

The above ratings reflect only the view, at the time the ratings are issued, of the applicable rating agency, from whom an explanation of the significance of such ratings may be obtained. Such 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.

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* Rating corresponds to HECO s rating (senior unsecured debt rating by S&P or issuer rating by Moody s) because, as a result of rating agency actions to lower or withdraw the ratings of these bond insurers after the bonds were issued, HECO s current ratings are either higher than the current rating of the applicable bond insurer or the bond insurer is not rated.

** Following MBIA Insurance Corporation s announced restructuring in February 2009, the revenue bonds issued for the benefit of HECO and its subsidiaries and insured by MBIA have been reinsured by MBIA Insurance Corp. of Illinois (MBIA Illinois), whose name was subsequently changed to National Public Finance Guarantee Corp. (National). The financial strength rating of National by S&P is A. Moody s ratings on securities that are guaranteed or wrapped by a financial guarantor are generally maintained at a level equal to the higher of the rating of the guarantor (if rated at the investment grade level) or the published underlying rating. The insurance financial strength rating of National by Moody s is Baa1, which is the same as Moody s issuer rating for HECO.

The rating agencies use a combination of qualitative measures (e.g., 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 May 2009, S&P revised HECO s outlook to negative from stable, and lowered HECO s short-term rating to A-3 from A-2. S&P indicated the rating actions reflected its view that the next two years are likely to be challenging for HEI s electric utilities. S&P stated that the deterioration in the Hawaii economy is likely to weaken 2009 and 2010 consolidated metrics, which it observed have been only marginally supportive of the BBB corporate credit ratings currently assigned to

HECO. In May 2010, S&P noted that [t]he negative outlook on Hawaiian Electric Company, Inc. (HECO) ratings reflects a weak consolidated financial profile that has been weighted down by the island recession and the need for more timely rate relief. We are concerned that 2010 could be another year of underperformance for HECO. HECO s stand-alone financial performance has been weak for the rating and has shown scant signs of improvement since 2007, a fact that underpins our negative outlook and the need to see improvement in 2010. S&P further stated that [w]e expect to lower the corporate credit rating on HECO one notch to BBB- unless we are able to see a clear path in 2010 to an improvement in HECO s credit metrics, which would at minimum require us to conclude that the electric utility is able to maintain funds from operations (FFO) to total debt of 15%, FFO interest coverage in the area of 3.5x, and leverage of less than 60%. S&P also indicated that [a]n upgrade is not likely due to HECO s need to restore its financial profile to levels consistent with the current rating.

On July 30, 2010, Moody s changed HECO s rating outlook to stable from negative and affirmed HECO s long-term and short-term (commercial paper) ratings. Moody s stated in its August 2, 2010 Credit Opinion on HECO:

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The ratings affirmation and outlook change reflects the progress being made by the company and various stakeholders to transform the regulatory framework for HEI s electric utilities to a decoupling structure that will reduce sales volume risk and produce more timely recovery of invested capital and operations and maintenance (O&M) costs .

The stable rating outlook incorporates our belief that the regulatory transition underway in Hawaii will proceed in an orderly fashion with the Hawaii PUC issuing the final decoupling order during 2010 for the three utilities.

In light of the sizeable capital investment programs and the remaining uncertainty that surrounds associated rate case decisions contemplated by HECO and its subsidiaries, limited near-term prospects exist for the rating to be upgraded. However, HECO s ratings could be upgraded if the regulatory transition underway is executed in an orderly fashion leading to an improvement in credit metrics such that the utility s cash flow to debt exceeds 22% and its cash flow coverage of interest is greater than 4.5x on a sustainable basis.

The rating could be downgraded if the Hawaii PUC does not follow through with the regulatory transformation contemplated under the HCEI, including all elements of the decoupling mechanism. Quantitatively, the ratings could be downgraded if the utilities cash flow to debt declined to below 17% on a sustainable basis and its cash flow coverage of interest fell below 3.5x.

The payment of principal and interest due on Special Purpose Revenue Bonds (SPRBs) currently outstanding and issued prior to 2009 are insured either by Ambac Assurance Corporation, Financial Guaranty Insurance Company, MBIA Insurance Corporation (MBIA) (which bonds have been reinsured by National Public Finance Guarantee Corp.) or Syncora Guarantee Inc. (which bonds have been reinsured by Syncora Capital Assurance Inc.). The insured outstanding revenue bonds were initially issued with S&P and Moody s ratings of AAA and Aaa, respectively, based on the ratings at the time of issuance of the applicable bond insurer. Beginning in 2008, however, ratings of the insurers (or their predecessors) were downgraded and/or withdrawn by S&P and Moody s, resulting in a downgrade of the bond ratings of all of the bonds as shown in the ratings table above. The $150 million of SPRBs sold by the DBF for the benefit of HECO and HELCO on July 30, 2009 were sold without bond insurance.

HECO and HELCO sold $93 million and $3 million, respectively, of their common stock to HEI and HECO, respectively, in December 2009. For HECO s $93 million of common stock, HECO received $62 million of cash from HEI and reduced its intercompany note payable to HEI by $31 million in a noncash transaction. On April 5, 2010, HECO, HELCO and MECO filed with the PUC an application for the approval of the sale of each utility s common stock over a five-year period from 2010 through 2014 (HECO s sale to HEI of up to $210 million and HELCO s and MECO s sales to HECO of up to $43 million and $15 million, respectively), and the purchase of the HELCO and MECO common stock by HECO over the five-year period.

Operating activities provided $116 million in net cash during the first nine months of 2010. Investing activities during the same period used net cash of $114 million for capital expenditures, net of contributions in aid of construction. Financing activities for the same period used net cash of $41 million, primarily due the payment of $40 million of common and preferred dividends.

Management periodically reviews capital expenditure estimates and the timing of construction projects. These estimates may change significantly as a result of many considerations, including changes in economic conditions, changes in forecasts of KWH sales and peak load, the availability of purchased power and changes in expectations concerning the construction and ownership of future generation units, the

availability of generating sites and transmission and distribution corridors, the need for fuel infrastructure investments, the ability to obtain adequate and timely rate increases, escalation in construction costs, commitments under the Energy Agreement, the impacts of DSM programs and CHP installations, the effects of opposition to proposed construction projects and requirements of environmental and other regulatory and permitting authorities.

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RESULTS OF OPERATIONS

(in thousands)	Three months ended September 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 71,429	$ 71,947	(1)	Lower interest income primarily due to lower earning asset balances (as a result of the sale of most of the 1-4 family residential loan production in 2009 and the first nine months of 2010 and the sale of the private-issue mortgage-related securities portfolio in the fourth quarter of 2009) and lower yields on earning assets (due to the lower interest rate environment), partly offset by higher noninterest income (due to an other-than-temporary impairment on the mortgage-related securities portfolio in the third quarter of 2009)
Operating income	24,389	17,689	38	Higher noninterest income (due to losses on available-for-sale securities in the third quarter in 2009) and lower noninterest expenses (due to the performance improvement project), partially offset by lower net interest income and higher provision for loan losses
Net income	15,293	11,323	35	Higher operating income, partly offset by higher income taxes

(in thousands)	Nine months ended September 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 213,975	$ 229,478	(7)	Lower interest income primarily due to lower earning asset balances (as a result of the sale of most of the 1-4 family residential loan production in 2009 and the first nine months of 2010 and the sale of the private-issue mortgage-related securities portfolio in the fourth quarter of 2009) and lower yields on earning assets (due to the lower interest rate environment), partly offset by higher noninterest income (due to an other-than-temporary impairment on the mortgage-related securities portfolio in 2009)
Operating income	71,935	40,316	78	Lower provision for loan losses, higher noninterest income (due to losses on available-for-sale securities in the second and third quarters in 2009) and lower noninterest expenses (due to the performance improvement project), partially offset by lower net interest income
Net income	45,160	26,226	72	Higher operating income, partly offset by higher income taxes

See Economic conditions in the HEI Consolidated section above.

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Average balance sheet and net interest margin. The following tables set forth average balances, together with interest and dividend income earned and accrued, and resulting yields and costs for the three and nine months ended September 30, 2010 and 2009.

	Three months ended September 30					
	2010			2009		
($ in thousands)	Average Balance	Interest	Average Rate (%)	Average Balance	Interest	Average Rate (%)
Assets:						
Other investments (1)	$ 335,002	$ 151	0.18	$ 270,177	$ 122	0.18
Investment and mortgage-related securities	586,706	3,701	2.52	662,419	6,821	4.12
Loans receivable (2)	3,555,997	49,221	5.52	3,845,469	53,080	5.51
Total interest-earning assets	4,477,705	53,073	4.73	4,778,065	60,023	5.01
Allowance for loan losses	(36,218)			(43,792)		
Non-interest-earning assets	418,266			346,107		
Total assets	$ 4,859,753			$ 5,080,380		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,419,983	776	0.13	$ 2,279,477	1,289	0.22
Time certificates	744,040	2,614	1.39	1,083,713	5,997	2.20
Total interest-bearing deposits	3,164,023	3,390	0.43	3,363,190	7,286	0.86
Other borrowings	257,156	1,414	2.16	397,327	2,205	2.17
Total interest-bearing liabilities	3,421,179	4,804	0.56	3,760,517	9,491	1.00
Non-interest bearing liabilities:						
Deposits	832,732			749,328		
Other	97,914			88,775		
Stockholder s equity	507,928			481,760		
Total Liabilities and Stockholder s Equity	$ 4,859,753			$ 5,080,380		
Net interest income		$ 48,269			$ 50,532	
Net interest margin (%) (3)			4.31			4.23

	Nine months ended September 30					
	2010			2009		
($ in thousands)	Average Balance	Interest	Average Rate (%)	Average Balance	Interest	Average Rate (%)
Assets:						
Other investments (1)	$ 347,418	$ 471	0.18	$ 202,570	$ 177	0.12
Investment and mortgage-related securities	539,348	10,344	2.56	660,450	21,585	4.36
Loans receivable (2)	3,625,186	148,294	5.46	3,999,395	166,535	5.56
Total interest-earning assets	4,511,952	159,109	4.70	4,862,415	188,297	5.17
Allowance for loan losses	(39,506)			(41,252)		
Non-interest-earning assets	413,051			345,201		
Total assets	$ 4,885,497			$ 5,166,364		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,400,738	2,732	0.15	$ 2,200,539	5,434	0.33
Time certificates	794,222	8,933	1.50	1,214,775	23,319	2.57

Total interest-bearing deposits	3,194,960	11,665	0.49	3,415,314	28,753	1.13
Other borrowings	275,045	4,258	2.05	453,738	7,710	2.24
Total interest-bearing liabilities	3,470,005	15,923	0.61	3,869,052	36,463	1.26
Non-interest bearing liabilities:						
Deposits	816,134			733,810		
Other	95,779			87,455		
Stockholder s equity	503,579			476,047		
Total Liabilities and Stockholder s Equity	$ 4,885,497			$ 5,166,364		
Net interest income		$ 143,186			$ 151,834	
Net interest margin (%) (3)			4.23			4.17

(1) Includes federal funds sold, interest bearing deposits and stock in the FHLB of Seattle ($98 million as of September 30, 2010).

(2) Includes loan fees of $2.1 million and $1.5 million for the three months ended September 30, 2010 and 2009, respectively, $4.7 million and $5.3 million for the nine months ended September 30, 2010 and 2009, respectively together with interest accrued prior to suspension of interest accrual on nonaccrual loans. Includes nonaccrual loans.

(3) Defined as net interest income as a percentage of average earning assets.

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Earning assets, costing liabilities and other factors. 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. The current interest rate environment is impacted by disruptions in the financial markets and these conditions may have a negative impact on ASB s net interest margin.

Loan originations and mortgage-related securities are ASB s primary sources of earning assets.

Loan portfolio. 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. The following table sets forth the composition of ASB s loan portfolio as of the dates indicated:

	September 30, 2010		December 31, 2009	
(dollars in thousands)	**Balance**	**% of total**	**Balance**	**% of total**
Real estate loans:				
Residential 1-4 family	$ 2,104,936	60.1	$ 2,319,738	62.5
Commercial real estate	280,318	8.0	255,458	6.9
Home equity line of credit	402,805	11.5	328,164	8.8
Residential land	75,880	2.1	96,515	2.6
Commercial construction	35,290	1.0	68,107	1.8
Residential construction	7,652	0.2	16,598	0.5
Total real estate loans, net	2,906,881	82.9	3,084,580	83.1
Commercial	514,095	14.7	542,686	14.6
Consumer	83,889	2.4	84,906	2.3
	3,504,865	100.0	3,712,172	100.0
Less: Allowance for loan losses	38,315		41,679	
Total loans, net	$ 3,466,550		$ 3,670,493	

The decrease in the total loan portfolio during the first nine months of 2010 was primarily due to ASB s strategic decision to sell most of the salable residential loans it originated during the nine month period ($254 million of loans sold).

Loan portfolio risk elements. When a borrower fails to make a required payment on a loan and does not cure the delinquency promptly, the loan is classified as delinquent. If delinquencies are not cured promptly, ASB normally commences a collection action, including foreclosure proceedings in the case of secured loans. In a foreclosure action, the property securing the delinquent debt is sold at a public auction in which ASB may participate as a bidder to protect its interest. If ASB is the successful bidder, the property is classified as real estate owned until it is sold.

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The following table sets forth certain information with respect to nonperforming assets as of the dates indicated:

(dollars in thousands)	September 30, 2010	December 31, 2009
Real estate loans:		
Residential 1-4 family	$ 35,309	$ 31,686
Commercial real estate	717	344
Home equity line of credit	1,829	2,755
Residential land	17,863	25,162
Commercial construction		
Residential construction		325
Total real estate loans, net	55,718	60,272
Commercial	4,731	4,171
Consumer	780	715
Total nonperforming loans	61,229	65,158
Real estate owned:		
Residential 1-4 family	1,493	1,806
Residential land	2,981	2,153
Total real estate owned loans	4,474	3,959
Total nonperforming assets	$ 65,703	$ 69,117
Nonperforming assets to total loans and REO	1.87%	1.85%

The level of nonperforming loans reflects the impact of current unemployment levels in Hawaii and the weak economic environment globally, nationally and in Hawaii.

Allowance for loan losses. The following table sets forth the allocation of ASB s allowance for loan losses and the percentage of loans in each category to total loans as of the dates indicated:

	September 30, 2010		December 31, 2009	
(dollars in thousands)	Balance	% of total	Balance	% of total
Real estate loans:				
Residential 1-4 family	$ 5,697	60.1	$ 5,522	62.5
Commercial real estate	1,385	8.0	861	6.9
Home equity line of credit	4,183	11.5	4,679	8.8
Residential land	2,981	2.1	4,252	2.6
Commercial construction	1,591	1.0	3,068	1.8
Residential construction	7	0.2	19	0.5
Total real estate loans, net	15,844	82.9	18,401	83.1
Commercial	18,293	14.7	19,498	14.6
Consumer	3,461	2.4	2,590	2.3
	37,598	100.0	40,489	100.0
Unallocated	717		1,190	
Total allowance for loan losses	$ 38,315		$ 41,679	
Total allowance for loan losses to end of period loans	1.09%		1.12%	

Investment and mortgage-related securities. As of September 30, 2010, the bank s investment portfolio consisted of 48% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), 47% federal agency obligations and 5% municipal bonds. As of December 31, 2009, the bank s investment portfolio consisted of 75% mortgage-related securities issued by FNMA, FHLMC or GNMA, 24% federal agency obligations and 1% municipal bonds.

Principal and interest on mortgage-related securities issued by FNMA, FHLMC and GNMA are guaranteed by the issuer, and the securities carry implied AAA ratings.

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Deposits and other borrowings. 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. Deposit retention and growth will remain challenges in the current environment due to competition for deposits and the level of short-term interest rates. Advances from the FHLB of Seattle and securities sold under agreements to repurchase continue to be additional sources of funds. As of September 30, 2010, ASB s costing liabilities consisted of 94% deposits and 6% borrowings. At December 31, 2009, ASB s costing liabilities consisted of 93% deposits and 7% other borrowings. The weighted average cost of deposits for the three and nine months ended September 30, 2010 were 0.34% and 0.39%, respectively, compared to the weighted average cost of deposits for the three and nine months ended September 30, 2009 of 0.70% and 0.93%, respectively.

Other factors. Interest rate risk is a significant risk of ASB s operations and also represents a market risk factor affecting the fair value of ASB s investment securities. Increases and decreases in prevailing interest rates generally translate into decreases and increases in fair value of those instruments. In addition, changes in credit spreads also impact the fair values of those instruments.

Although higher long-term interest rates or other conditions in credit markets (such as the effects of the deteriorated subprime market) could reduce the market value of available-for-sale investment and mortgage-related securities and reduce stockholder s equity through a balance sheet charge to AOCI, this reduction in the market value of investments and mortgage-related securities would not result in a charge to net income in the absence of a sale of such securities (such as those that occurred in the fourth quarter of 2009 and in the 2008 balance sheet restructure) or an other-than-temporary impairment in the value of the securities. As of September 30, 2010 and December 31, 2009, the unrealized gains, net of taxes, on available-for-sale investments and mortgage-related securities (including securities pledged for repurchase agreements) in AOCI was $7 million and $5 million, respectively. See Quantitative and qualitative disclosures about market risk.

Results three and nine months ended September 30, 2010.Net interest income before provision for loan losses for the third quarter and first nine months of 2010 decreased by 4% and 6%, respectively, when compared to the same period in 2009 as lower funding costs were more than offset by the impact of lower average balances and yields on interest-earning assets.

Average deposit balances in 2010 decreased compared to the third quarter and first nine months of 2009 due to decreases in the average time certificate balance as ASB did not aggressively price its time certificate products, partly offset by increases in the average core deposit balance as ASB introduced new core deposit products. The shift in deposit mix from higher cost time certificates to lower cost savings and checking accounts, along with the repricing of deposits as a result of a downward movement in the general level of interest rates, has contributed to the decreased funding costs in 2010. Also, higher costing other borrowings decreased primarily due to the payoff of maturing amounts.

The decrease in funding costs was partly offset by lower yields on the investment and mortgage-related securities portfolio as ASB sold its higher yielding private-issue mortgage-related securities portfolio in the fourth quarter of 2009 to reduce ASB s overall credit risk and had challenges finding investments with adequate risk-adjusted returns for its excess liquidity, leading it to invest its excess liquidity in other investments (primarily deposit accounts) bearing low interest rates. ASB s average loan portfolio balances decreased due to decreases in the average 1-4 family residential loan portfolio as ASB sold most of its salable residential loan production during 2009 and the first nine months of 2010. The net interest margin of 4.31% for the third quarter of 2010 would have been approximately 9 basis points lower, or 4.22%, if not for the accelerated recognition of deferred fees primarily due to loan repayments which are typically high in this type of low interest rate environment. Average commercial, residential land and construction loan balances decreased due to paydowns in those portfolios. The average home equity line of credit portfolio balance increased due to a promotional campaign in the first half of 2010. In the second and third quarters of 2010, to utilize its excess liquidity, ASB purchased securities, primarily federal agency obligations that had generally shorter durations.

During the third- quarter of 2010, ASB recorded a provision for loan losses of $6.0 million due in part to the reclassification of certain commercial loans that are current as to principal and interest payments, but have identified weaknesses, and net charge-offs in 1-4 family residential loans, residential land loans and home equity

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lines of credit. During the third quarter of 2009, ASB recorded a provision for loan losses of $5.2 million due in part to higher nonperforming residential land loans and higher delinquencies in residential and consumer loans. During the first nine months of 2010, ASB recorded a provision for loan losses of $12.3 million primarily due to net charge-offs for 1-4 family and residential land loans. During the first nine months of 2009, ASB recorded a provision for loan losses of $27 million due to the classification and partial charge-off of a commercial credit, higher nonperforming residential land loans and higher residential and consumer loan delinquencies. Continued financial stress on ASB s customers may result in higher levels of delinquencies and losses.

	Nine months ended September 30		Year ended December 31
(in thousands)	**2010**	**2009**	**2009**
Allowance for loan losses, January 1	$ 41,679	$ 35,798	$ 35,798
Provision for loan losses	12,310	27,000	32,000
Less: net charge-offs	15,674	16,900	26,119
Allowance for loan losses, end of period	$ 38,315	$ 45,898	$ 41,679
Ratio of allowance for loan losses, end of period, to end of period loans outstanding	1.09%	1.21%	1.12%
Ratio of net charge-offs during the period to average loans outstanding (annualized)	0.58%	0.56%	0.66%
Nonaccrual loans	$ 55,561	$ 62,095	$ 65,323

Third quarter of 2010 noninterest income increased by $6.4 million, or 54%, when compared to the third quarter of 2009, primarily due to a $9.9 million other-than-temporary impairment charge on its mortgage-related securities portfolio in the third quarter of 2009. Fee income on deposit liabilities for the third quarter of 2010 was $2.1 million lower than the same period in 2009 as new overdraft fee rules, which became effective in the third quarter of 2010, decreased overdraft fees by approximately $1.8 million.

First nine months of 2010 noninterest income increased by $13.7 million, or 33%, when compared to the first nine months of 2009, primarily due to other-than-temporary impairment charges on its mortgage-related securities portfolio in 2009, partially offset by a lower gain on sale of loans in 2010. The gain on sale of loans for 2009 included the sale of a commercial loan.

	Three months ended September 30		Nine months ended September 30	
(in thousands)	**2010**	**2009**	**2010**	**2009**
Fee income on deposit liabilities	$ 6,109	$ 8,211	$ 21,520	$ 22,384
Fees from other financial services	6,781	6,385	19,844	18,747
Fee income on other financial products	1,697	1,613	4,957	4,285
Net gains (losses) on available-for-sale securities		(9,863)		(15,400)
Other income				
Gain on sale of loans	2,490	4,302	4,610	7,834
Bank-owned life insurance	1,019	1,022	3,013	3,000
Other	260	254	922	331
Total noninterest income	$ 18,356	$ 11,924	$ 54,866	$ 41,181

Noninterest expense for the third quarter of 2010 decreased by $3.3 million, or 8%, when compared to the third quarter of 2009. Lower data processing, occupancy and services expenses were the result of ASB s process improvement project, which reduced the ASB s cost structure through improved processes and procedures, and improved the efficiency of ASB.

Noninterest expense for the first nine months of 2010 decreased by $11.9 million, or 9%, when compared to the first nine months of 2009. Lower compensation, occupancy, equipment and services expenses were the result of ASB s process improvement project. The increase in data processing expense was primarily due to costs incurred to convert ASB s systems to Fiserv Inc. s bank platform system. The FDIC insurance premium in the first nine months of 2009 included a special assessment of $2.3 million.

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(in thousands)	Three months ended September 30 2010	2009	Nine months ended September 30 2010	2009
Compensation and benefits	$ 18,168	$ 17,721	$ 54,477	$ 55,072
Occupancy	4,176	4,905	12,617	15,956
Data processing	2,019	3,684	10,921	10,352
Services	1,544	2,437	5,117	9,656
Equipment	1,600	1,782	4,949	7,112
Other				
FDIC insurance premium	1,500	1,639	4,758	7,140
Marketing	385	548	1,709	1,763
Office supplies, printing and postage	990	937	2,984	2,828
Communication	599	597	1,608	1,881
Other	5,324	5,341	14,760	14,016
Total noninterest expense	$ 36,305	$ 39,591	$ 113,900	$ 125,776

Legislation and regulation. ASB is subject to extensive regulation, principally by the Office of Thrift Supervision (OTS), whose regulatory functions are to be transferred to the Office of the Comptroller of the Currency (OCC) as described below, and the FDIC. Depending on ASB s 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 discussion below under Liquidity and capital resources. Also see Federal Deposit Insurance Corporation restoration plan and Deposit insurance coverage in Note 4 of HEI s Notes to Consolidated Financial Statements.

In January 2010, the FDIC released for comment a proposal to modify its risk-based deposit insurance system to account for risks posed by the compensation systems of insured banks and their holding companies. Management cannot predict at this time whether the proposed rule will be adopted as proposed or in some modified form or, if adopted, what impact it may have on ASB s FDIC insurance rate.

Dodd-Frank Wall Street Reform and Consumer Protection Act. Regulation of the financial services industry, including regulation of HEI and ASB, will undergo substantial changes as a result of the enactment of the Dodd-Frank Act. The Dodd-Frank Act increases regulation and oversight of the financial services industry and imposes restrictions on the ability of firms within the industry to conduct business consistent with historical practices. Most importantly for HEI and ASB, the Dodd-Frank Act will abolish their historical federal financial institution regulator, the OTS, effective one year from the enactment date (subject to extension by not more than an additional six months). Supervision and regulation over HEI, as a thrift holding company, will move to the Federal Reserve, and supervision and regulation over ASB, as a federally chartered savings bank, will move to the OCC. While the laws and regulations applicable to HEI and ASB will not generally change the Home Owners Loan Act and regulations issued thereunder will still apply the applicable laws and regulations will be interpreted, and new and amended regulations will be adopted, by the Federal Reserve and the OCC, respectively. HEI will for the first time be subject to minimum consolidated capital requirements, and ASB may be required to be supervised through ASHI, its intermediate holding company. The Dodd-Frank Act requires regulators, at a minimum, to apply to bank and thrift holding companies leverage and risk-based capital standards that are at least as strict as those in effect at the insured depository institution level on the date the Act became effective, although there will be a phase-in period for meeting these standards. In addition, HEI will continue to be required to serve as a source of strength to ASB in the event of its financial distress. The Dodd-Frank Act also imposes new restrictions on the ability of a savings bank to pay dividends should it fail to remain a qualified thrift lender.

More stringent affiliate transaction rules will apply to ASB in the securities lending, repurchase agreement and derivatives areas. Standards are raised with respect to the ability of ASB to merge with or acquire another institution. While the Dodd-Frank Act requires the minimum reserve ratio for the Deposit Insurance Fund to be increased from 1.15% to 1.35% by 2020, this change may not impact ASB because in establishing assessments the FDIC is required to offset the effect of this increase for depository institutions with total consolidated assets of less than $10 billion. ASB may be affected by the provision of the Dodd-Frank Act that repeals, effective in July

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2011, the prohibition on payments of interest by banks or savings associations on demand deposit accounts for businesses.

The Dodd-Frank Act establishes a Consumer Financial Protection Bureau (Bureau) to be housed in the Federal Reserve to take sole responsibility (subject to limited oversight by the new Financial Stability Oversight Council) for rulemaking under the principal federal consumer financial protection laws, such as the Truth in Lending Act, Real Estate Settlement Procedures Act, Equal Credit Opportunity Act, Truth in Savings Act, Fair Debt Collection Practices Act and several other consumer protection laws, but enforcement of these laws and rules will be by the OCC in the case of ASB because it has less than $10 billion in assets. The Bureau will have broad power in that it will have authority to prohibit practices it finds to be unfair, deceptive or abusive, and it may also issue rules requiring specified disclosures, including the use of new model forms it may adopt. ASB may also be subject to new state regulation because of a provision in the Dodd-Frank Act that acknowledges that a federal savings bank may be subject to state regulation and only allows federal law to preempt state law on a case by case basis in the consumer financial protection area when (1) the state law would have a discriminatory effect on the bank compared to that on a bank chartered in that state; (2) the state law prevents or significantly interferes with a bank s exercise of its power; or (3) the state law is preempted by another federal law.

The Dodd-Frank Act also adopts a number of provisions that will impact the mortgage industry, including the imposition of new specific duties on the part of mortgage originators (such as ASB) to act in the best interests of consumers and to take steps to ensure that consumers will have the capability to repay loans they may obtain, as well as provisions imposing new disclosure requirements and requiring appraisal reforms. Regulations are required to be adopted under these provisions of the Dodd-Frank Act within 18 months after the date that is to be specified by the Secretary of the Treasury for the transfer of consumer protection power to the Bureau. ASB cannot predict at this time what effect these new rules may ultimately have on its mortgage origination practices, its ability to originate mortgage loans or the costs it will incur in complying with these requirements.

The Dodd-Frank Act will affect financial regulation more generally as well, although many of these regulatory changes may not impact ASB or the Company directly, either because they are limited in application to larger entities or because they relate to activities in which ASB is not substantially engaged. For example, the Dodd-Frank Act establishes a Financial Stability Oversight Council that would, among other things, designate certain nonbank financial companies that it considers to be of systemic risk to be supervised by the Federal Reserve, as well as monitor the financial markets for trends affecting systemic risk and coordinate the regulatory activities of the federal bank regulators. It also would establish a mechanism for the FDIC to resolve systemically important companies that may fail. The ability of companies to engage in derivatives transactions and hedge for their own account likely will be impacted by provisions in the Dodd-Frank Act that require such transactions to be moved to exchanges and for capital and margin to be held against them, as well as by the so-called Volcker rule, which will limit the ability of financial institutions to invest for their own account once the rule becomes effective (but with exceptions important to ASB, such as for purchases of U.S. government or agency obligations).

HEI will also be affected by provisions of the Dodd-Frank Act relating to corporate governance and executive compensation, including provisions requiring shareholder say on pay votes, mandating additional disclosures concerning executive compensation and compensation consultants and advisors, further restricting proxy voting by brokers in the absence of instructions and permitting the SEC to adopt rules in its discretion requiring public companies under specified conditions to include shareholder nominees in management s proxy solicitation materials.

Many of the provisions of the Dodd-Frank Act will not become effective until a year or more after its enactment, when implementing regulations are issued and effective. Thus, management cannot predict the ultimate impact of the Dodd-Frank Act on the Company or ASB at this time. Nor can management predict the impact or substance of other future federal or state legislation or regulation, or the application thereof.

New overdraft rules. On November 12, 2009, the Board of Governors of the Federal Reserve System announced that it amended Regulation E (which implements the Electronic Fund Transfer Act) to limit the ability of a financial institution to assess an overdraft fee for paying automated teller machine or one-time debit card transactions that overdraw a consumer s account, unless the consumer affirmatively consents, or opts in, to the

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institution s payment of overdrafts for those transactions. These new rules apply on July 1, 2010 for new accounts and August 15, 2010 for existing accounts. In 2009, these types of overdraft fees totaled approximately $15 million pretax. The amendment had a negative impact on ASB s noninterest income of approximately $1.8 million pretax for the third quarter of 2010.

FHLB of Seattle stock. As of September 30, 2010, ASB s investment in stock of the FHLB of Seattle of $97.8 million was carried at cost because it can only be redeemed at par. There is a minimum required investment based on measurements of ASB s capital, assets and/or borrowing levels. The FHLB of Seattle reported net income of $8.2 million for the second quarter of 2010 compared to a net loss of $34.3 million for the same period in 2009. The FHLB of Seattle reported retained earnings of $67.2 million and was in compliance with all of its regulatory capital requirements. However, the FHLB of Seattle remains classified as undercapitalized by its regulator, the Federal Housing Finance Agency, and may not redeem or repurchase capital stock or pay dividends on its stock. ASB does not believe that the Federal Housing Finance Agency s classification of the FHLB of Seattle will affect the FHLB of Seattle s ability to meet ASB s liquidity and funding needs. ASB did not receive cash dividends on its $97.8 million of FHLB of Seattle stock in 2009 or the first nine months of 2010.

Periodically and as conditions warrant, ASB reviews its investment in the stock of FHLB of Seattle for impairment.

Commitments and contingencies. See Note 4 of HEI s Notes to Consolidated Financial Statements.

Recent accounting pronouncements and interpretations. See Note 12 of HEI s Notes to Consolidated Financial Statements.

FINANCIAL CONDITION

Liquidity and capital resources.

(in millions)	September 30, 2010	December 31, 2009	% change
Total assets	$ 4,804	$ 4,941	(3)
Available-for-sale investment and mortgage-related securities	570	433	32
Loans receivable, net	3,467	3,670	(6)
Deposit liabilities	3,959	4,059	(2)
Other bank borrowings	247	298	(17)

As of September 30, 2010, ASB was one of Hawaii s largest financial institutions based on assets of $4.8 billion and deposits of $4.0 billion.

In July 2010, Moody s affirmed ASB s counterparty credit rating of A3 and changed ASB s outlook to stable from negative based on ASB s better than expected asset quality and earnings performance in the last several periods. In April 2007, S&P raised ASB s long-term/short-term

counterparty credit ratings to BBB/A-2 from BBB-/A-3 and in July 2010 maintained the rating following its annual review of ASB.

As of September 30, 2010, ASB s unused FHLB borrowing capacity was approximately $1.4 billion. As of September 30, 2010, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.2 billion. Management believes ASB s current sources of funds will enable it to meet these obligations while maintaining liquidity at satisfactory levels.

As of September 30, 2010 and December 31, 2009, ASB had $61.2 million and $65.2 million of nonperforming loans, respectively.

As of September 30, 2010 and December 31, 2009, ASB had $4.5 million and $4.0 million, respectively, of real estate acquired in settlement of loans.

For the first nine months of 2010, net cash provided by ASB s operating activities was $89 million. Net cash provided during the same period by ASB s investing activities was $34 million, primarily due to repayments of investment and mortgage-related securities of $351 million, a net decrease in loans receivable of $171 million and proceeds from the sale of real estate acquired in settlement of loans of $3 million, offset by purchases of investment and mortgage-related securities of $485 million and additions to premises and equipment of $6 million. Net cash used in financing activities during this period was $199 million, primarily due to net decreases in deposit

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liabilities and retail repurchase agreements of $100 million and $51 million, respectively, a decrease in mortgage escrow deposits of $5 million and the payment of $43 million in common stock dividends.

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 September 30, 2010, ASB was well-capitalized (minimum ratio requirements noted in parentheses) with a leverage ratio of 9.3% (5.0%), a Tier-1 risk-based capital ratio of 13.1% (6.0%) and a total risk-based capital ratio of 14.2% (10.0%). OTS approval is required before ASB can make a capital distribution to HEI.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The Company considers interest-rate risk (a non-trading market risk) to be a very significant market risk for ASB as it could potentially have a significant effect on the Company s financial condition and results of operations. For additional quantitative and qualitative information about the Company s market risks, see pages 63 to 65, HEI s Quantitative and Qualitative Disclosures About Market Risk, which is incorporated into Part II, Item 7A of HEI s 2009 Form 10-K by reference to HEI Exhibit 13 to HEI s Current Report on Form 8-K dated February 19, 2010 and page 3, HECO sQuantitative and Qualitative Disclosures About Market Risk, which is incorporated into Part II, Item 7A of HECO s 2009 Form 10-K by reference to Exhibit 99 to HECO s Current Report on Form 8-K dated February 19, 2010.

ASB s interest-rate risk sensitivity measures as of September 30, 2010 and December 31, 2009 constitute forward-looking statements and were as follows:

	September 30, 2010			December 31, 2009		
Change in interest rates (basis points)	Change in NII Gradual change	NPV ratio Instantaneous change	NPV ratio sensitivity * Instantaneous change	Change in NII Gradual change	NPV ratio Instantaneous change	NPV ratio sensitivity * Instantaneous change
+300	0.6%	11.65	(144)	(0.3)%	10.92%	(245)
+200	0.1	12.40	(69)	(0.3)	11.86	(151)
+100		12.93	(16)	(0.2)	12.72	(65)
Base		13.09			13.37	
-100	(0.7)	12.85	(24)	(0.9)	13.53	16
-200	**	**	**	**	**	**
-300	**	**	**	**	**	**

* Change from base case in basis points (bp).

** For September 30, 2010 and December 31, 2009, the -200 and -300 bp scenarios were not performed because they would have resulted in negative Treasury interest rates.

ASB s net interest income (NII) sensitivity as of September 30, 2010 was slightly asset sensitive for rising rates compared to December 31, 2009 due to faster prepayment expectations and changes in balance sheet mix.

ASB s base net present value (NPV) ratio as of September 30, 2010 decreased compared to December 31, 2009 primarily due to the decline in the level of interest rates and changes in balance sheet mix.

ASB s NPV ratio sensitivity measure as of September 30, 2010 decreased compared to December 31, 2009 in the rising interest rate scenarios primarily due to the flattening of the yield curve and shift in assets to shorter duration loans and investments.

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 (see pages 63-65 of HEI Exhibit 13 to HEI s Current Report on Form 8-K dated February 19, 2010 for a more detailed description of key modeling assumptions used in the NII sensitivity analysis). 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

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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 ASB s balance sheet, and management s responses to the changes in interest rates.

Item 4. Controls and Procedures

HEI:

Changes in Internal Control over Financial Reporting

During the third quarter of 2010, there were no changes in internal control over financial reporting identified in connection with management s evaluation of the effectiveness of the Company s internal control over financial reporting as of September 30, 2010 that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Constance H. Lau, HEI Chief Executive Officer, and James A. Ajello, HEI Chief Financial Officer, have evaluated the disclosure controls and procedures of HEI as of September 30, 2010. Based on their evaluations, as of September 30, 2010, they have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective in ensuring that information required to be disclosed by HEI in reports HEI files or submits under the Securities Exchange Act of 1934:

(1) is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and

(2) is accumulated and communicated to HEI management, including HEI s principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

HECO:

Changes in Internal Control over Financial Reporting

During the third quarter of 2010, there was no change in internal control over financial reporting identified in connection with management s evaluation of the effectiveness of HECO and its subsidiaries internal control over financial reporting as of September 30, 2010 that has materially affected, or is reasonably likely to materially affect, HECO and its subsidiaries internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Richard M. Rosenblum, HECO Chief Executive Officer, and Tayne S. Y. Sekimura, HECO Chief Financial Officer, have evaluated the disclosure controls and procedures of HECO as of September 30, 2010. Based on their evaluations, as of September 30, 2010, they have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective in ensuring that information required to be disclosed by HECO in reports HECO files or submits under the Securities Exchange Act of 1934:

(1) is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and

(2) is accumulated and communicated to HECO management, including HECO s principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

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PART II - OTHER INFORMATION

Item 1. Legal Proceedings

The descriptions of legal proceedings (including judicial proceedings and proceedings before the PUC and environmental and other administrative agencies) in HEI s Form 10-K (see Part I. Item 3. Legal Proceedings and proceedings referred to therein) and this 10-Q (see Management s Discussion and Analysis of Financial Condition and Results of Operations and HECO s Notes to Consolidated Financial Statements) are incorporated by reference in this Item 1. With regard to any pending legal proceeding, alternative dispute resolution, such as mediation or settlement, may be pursued where appropriate, with such efforts typically maintained in confidence unless and until a resolution is achieved. Certain HEI subsidiaries (including HECO and its subsidiaries and ASB) may also be involved in ordinary routine PUC proceedings, environmental proceedings and litigation incidental to their respective businesses.

Item 1A. Risk Factors

For information about Risk Factors, see pages 30 to 39 of HEI s 2009 Form 10-K, and Management s Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures about Market Risk, HEI s Consolidated Financial Statements and HECO s Consolidated Financial Statements herein. Also, see Forward-Looking Statements on pages v and vi of HEI s 2009 Form 10-K, as updated on pages iv and v herein.

Item 5. Other Information

A. Ratio of earnings to fixed charges.

	Nine months ended September 30		Years ended December 31				
	2010	2009	2009	2008	2007	2006	2005
HEI and Subsidiaries							
Excluding interest on ASB deposits	2.93	2.49	2.29	2.06	1.78	2.08	2.31
Including interest on ASB deposits	2.66	2.05	1.95	1.71	1.52	1.73	1.98
HECO and Subsidiaries	2.86	2.92	2.99	3.48	2.43	3.14	3.23

See HEI Exhibit 12.1 and HECO Exhibit 12.2.

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Item 6. Exhibits

HEI Exhibit 12.1	Hawaiian Electric Industries, Inc. and Subsidiaries Computation of ratio of earnings to fixed charges, nine months ended September 30, 2010 and 2009 and years ended December 31, 2009, 2008, 2007, 2006 and 2005
HEI Exhibit 31.1	Certification Pursuant to Rule 13a-14 promulgated under the Securities Exchange Act of 1934 of Constance H. Lau (HEI Chief Executive Officer)
HEI Exhibit 31.2	Certification Pursuant to Rule 13a-14 promulgated under the Securities Exchange Act of 1934 of James A. Ajello (HEI Chief Financial Officer)
HEI Exhibit 32.1	Written Statement of Constance H. Lau (HEI Chief Executive Officer) Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted by Section 906 of the Sarbanes-Oxley Act of 2002
HEI Exhibit 32.2	Written Statement of James A. Ajello (HEI Chief Financial Officer) Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted by Section 906 of the Sarbanes-Oxley Act of 2002
HEI Exhibit 101.INS	XBRL Instance Document
HEI Exhibit 101.SCH	XBRL Taxonomy Extension Schema Document
HEI Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
HEI Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
HEI Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase Document
HEI Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
HECO Exhibit 12.2	Hawaiian Electric Company, Inc. and Subsidiaries Computation of ratio of earnings to fixed charges, nine months ended September 30, 2010 and 2009 and years ended December 31, 2009, 2008, 2007, 2006 and 2005
HECO	

Exhibit 31.3	Certification Pursuant to Rule 13a-14 promulgated under the Securities Exchange Act of 1934 of Richard M. Rosenblum (HECO Chief Executive Officer)
HECO Exhibit 31.4	Certification Pursuant to Rule 13a-14 promulgated under the Securities Exchange Act of 1934 of Tayne S. Y. Sekimura (HECO Chief Financial Officer)
HECO Exhibit 32.3	Written Statement of Richard M. Rosenblum (HECO Chief Executive Officer) Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted by Section 906 of the Sarbanes-Oxley Act of 2002
HECO Exhibit 32.4	Written Statement of Tayne S. Y. Sekimura (HECO Chief Financial Officer) Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted by Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized. The signature of the undersigned companies shall be deemed to relate only to matters having reference to such companies and any subsidiaries thereof.

HAWAIIAN ELECTRIC INDUSTRIES, INC.
(Registrant)

By	/s/ Constance H. Lau Constance H. Lau President and Chief Executive Officer (Principal Executive Officer of HEI)
By	/s/ James A. Ajello James A. Ajello Senior Financial Vice President, Treasurer and Chief Financial Officer (Principal Financial Officer of HEI)
By	/s/ David M. Kostecki David M. Kostecki Vice President-Finance, Controller and Chief Accounting Officer (Principal Accounting Officer of HEI)

Date: November 3, 2010

HAWAIIAN ELECTRIC COMPANY, INC.
(Registrant)

By	/s/ Richard M. Rosenblum Richard M. Rosenblum President and Chief Executive Officer (Principal Executive Officer of HECO)
By	/s/ Tayne S. Y. Sekimura Tayne S. Y. Sekimura Senior Vice President and Chief Financial Officer (Principal Financial Officer of HECO)
By	/s/ Patsy H. Nanbu Patsy H. Nanbu Controller (Principal Accounting Officer of HECO)

Date: November 3, 2010