HAWAIIAN ELECTRIC CO INC
Form 10-Q
August 09, 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 June 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 July 30, 2010
Hawaiian Electric Industries, Inc. (Without Par Value)	93,680,089 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 Industries, Inc. and Subsidiaries

Hawaiian Electric Company, Inc. and Subsidiaries

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Hawaiian Electric Industries, Inc. and Subsidiaries

Hawaiian Electric Company, Inc. and Subsidiaries

Form 10-Q Quarter ended June 30, 2010

GLOSSARY OF TERMS

Terms	Definitions
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income
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 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
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

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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 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
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, such as the Emergency Economic Stabilization Act of 2008 and the American Recovery and Reinvestment Act of 2009;

- 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 Iraq and 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 and its subsidiaries) 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, 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 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; 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 June 30 2010	2009	Six months ended June 30 2010	2009
Revenues				
Electric utility	$ 584,095	$ 450,417	$ 1,132,206	$ 912,214
Bank	71,632	75,499	142,546	157,531
Other	(63)	(15)	(48)	(47)
	655,664	**525,901**	**1,274,704**	**1,069,698**
Expenses				
Electric utility	542,660	418,254	1,048,162	848,982
Bank	45,857	69,993	95,000	134,904
Other	3,516	2,599	7,204	6,099
	592,033	**490,846**	**1,150,366**	**989,985**
Operating income (loss)				
Electric utility	41,435	32,163	84,044	63,232
Bank	25,775	5,506	47,546	22,627
Other	(3,579)	(2,614)	(7,252)	(6,146)
	63,631	**35,055**	**124,338**	**79,713**
Interest expense other than on deposit liabilities and other bank borrowings	(20,520)	(17,910)	(40,901)	(35,743)
Allowance for borrowed funds used during construction	790	1,727	1,569	3,349
Allowance for equity funds used during construction	1,847	4,120	3,620	7,725
Income before income taxes	**45,748**	**22,992**	**88,626**	**55,044**
Income taxes	16,013	7,040	31,292	18,224
Net income	**29,735**	**15,952**	**57,334**	**36,820**
Preferred stock dividends of subsidiaries	473	473	946	946
Net income for common stock	**$ 29,262**	**$ 15,479**	**$ 56,388**	**$ 35,874**
Basic earnings per common share	$ 0.31	$ 0.17	$ 0.61	$ 0.39
Diluted earnings per common share	$ 0.31	$ 0.17	$ 0.61	$ 0.39
Dividends per common share	$ 0.31	$ 0.31	$ 0.62	$ 0.62
Weighted-average number of common shares outstanding	93,159	91,384	92,867	90,996
Dilutive effect of share-based compensation	255	110	292	92
Adjusted weighted-average shares	93,414	91,494	93,159	91,088

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)	June 30, 2010	December 31, 2009
Assets		
Cash and cash equivalents	$ 278,324	$ 503,922
Accounts receivable and unbilled revenues, net	266,701	241,116
Available-for-sale investment and mortgage-related securities	623,965	432,881
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,573,131	3,670,493
Property, plant and equipment, net of accumulated depreciation of $1,996,286 and $1,945,482	3,106,812	3,088,611
Regulatory assets	424,614	426,862
Other	426,860	381,163
Goodwill, net	82,190	82,190
	$ 8,880,361	$ 8,925,002
Liabilities and stockholders equity		
Liabilities		
Accounts payable	$ 164,538	$ 159,044
Interest and dividends payable	30,829	27,950
Deposit liabilities	4,001,534	4,058,760
Short-term borrowings other than bank	55,012	41,989
Other bank borrowings	256,515	297,628
Long-term debt, net other than bank	1,364,879	1,364,815
Deferred income taxes	187,809	188,875
Regulatory liabilities	293,299	288,214
Contributions in aid of construction	326,050	321,544
Other	698,970	700,242
	7,379,435	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: 93,619,909 shares and 92,520,638 shares	1,289,471	1,265,157
Retained earnings	183,015	184,213
Accumulated other comprehensive loss, net of tax benefits	(5,853)	(7,722)
	1,466,633	1,441,648
	$ 8,880,361	$ 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		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					56,388				56,388
Net unrealized gains (losses) on securities:									
Net unrealized gains on securities arising during the period, net of taxes of $1,747							2,646		2,646
Unrealized losses on derivatives qualified as cash flow hedges:									
Unrealized holding loss arising during the period, net of tax benefits of $662							(1,039)		(1,039)
Retirement benefit plans:									
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,248							1,959		1,959
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,080							(1,697)		(1,697)
Comprehensive income					56,388		1,869		58,257
Issuance of common stock, net	1,099		24,314						24,314
Common stock dividends ($0.62 per share)					(57,586)				(57,586)
Balance, June 30, 2010	**93,620**	**$**	**1,289,471**	**$**	**183,015**	**$**	**(5,853)**	**$**	**1,466,633**
Balance, December 31, 2008	**90,516**	**$**	**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					35,874				35,874
Net unrealized gains (losses) on securities:									
Net unrealized gains on securities arising during the period, net of taxes of $14,237							21,561		21,561
Net unrealized losses related to factors other than credit during the period, net of tax benefits of $5,147							(7,794)		(7,794)
Less: reclassification adjustment for net realized losses included in net income, net of tax benefits of $2,202							3,335		3,335
Retirement benefit plans:									
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $3,718							5,827		5,827
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $3,333							(5,233)		(5,233)
Comprehensive income					35,874		17,696		53,570
Issuance of common stock, net	1,046		15,199						15,199
Common stock dividends ($0.62 per share)					(56,477)				(56,477)

Balance, June 30, 2009	**91,562**	**$**	**1,246,828**	**$**	**194,018**	**$**	**(39,100)**	**$**	**1,401,746**

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)

Six months ended June 30 **(in thousands)**	**2010**	**2009**
Cash flows from operating activities		
Net income	$ 57,334	$ 36,820
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	79,606	76,999
Other amortization	2,149	2,484
Provision for loan losses	6,349	21,800
Loans receivable originated and purchased, held for sale	(136,197)	(291,500)
Proceeds from sale of loans receivable, held for sale	167,583	322,692
Net gain on sale of investment and mortgage-related securities		(44)
Other-than-temporary impairment of available-for-sale mortgage-related securities		5,581
Changes in deferred income taxes	(2,381)	3,973
Changes in excess tax benefits from share-based payment arrangements	97	318
Allowance for equity funds used during construction	(3,620)	(7,725)
Decrease in cash overdraft	(302)	
Changes in assets and liabilities		
Decrease (increase) in accounts receivable and unbilled revenues, net	(25,012)	88,308
Decrease (increase) in fuel oil stock	(49,759)	22,383
Increase (decrease) in accounts, interest and dividends payable	8,373	(20,748)
Changes in prepaid and accrued income taxes and utility revenue taxes	(30,699)	(56,397)
Changes in other assets and liabilities	11,732	(24,633)
Net cash provided by operating activities	**85,253**	**180,311**
Cash flows from investing activities		
Available-for-sale investment and mortgage-related securities purchased	(379,896)	(190,095)
Principal repayments on available-for-sale investment and mortgage-related securities	203,783	248,109
Proceeds from sale of available-for-sale investment and mortgage-related securities		44
Net decrease in loans held for investment	61,017	305,381
Proceeds from sale of real estate acquired in settlement of loans	2,118	
Capital expenditures	(83,673)	(175,092)
Contributions in aid of construction	9,430	4,917
Other	(10)	86
Net cash provided by (used in) investing activities	**(187,231)**	**193,350**
Cash flows from financing activities		
Net decrease in deposit liabilities	(57,226)	(11,467)
Net increase in short-term borrowings with original maturities of three months or less	13,023	55,000
Net decrease in retail repurchase agreements	(41,112)	(24,592)
Proceeds from other bank borrowings		310,000
Repayments of other bank borrowings		(577,517)
Proceeds from issuance of long-term debt		3,168
Changes in excess tax benefits from share-based payment arrangements	(97)	(318)
Net proceeds from issuance of common stock	10,789	8,786
Common stock dividends	(46,246)	(51,127)
Preferred stock dividends of subsidiaries	(946)	(946)
Decrease in cash overdraft		(962)
Other	(1,805)	(1,190)
Net cash used in financing activities	**(123,620)**	**(291,165)**
Net increase (decrease) in cash and cash equivalents	(225,598)	82,496
Cash and cash equivalents, beginning of period	503,922	183,435

Cash and cash equivalents, end of period	**$**	**278,324**	**$**	**265,931**

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 Report on SEC Form 10-Q for the quarter ended March 31, 2010.

In the opinion of HEI s management, the accompanying unaudited consolidated financial statements contain all material adjustments required by GAAP to present fairly the Company s financial position as of June 30, 2010 and December 31, 2009, the results of its operations for the three and six months ended June 30, 2010 and 2009 and cash flows for the six months ended June 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 June 30, 2010				
Revenues from external customers	$ 584,048	$ 71,632	$ (16)	$ 655,664
Intersegment revenues (eliminations)	47		(47)	
Revenues	584,095	71,632	(63)	655,664
Profit (loss)*	28,354	25,747	(8,353)	45,748
Income taxes (benefit)	10,213	9,616	(3,816)	16,013
Net income (loss)	18,141	16,131	(4,537)	29,735
Preferred stock dividends of subsidiaries	499		(26)	473
Net income (loss) for common stock	17,642	16,131	(4,511)	29,262
Six months ended June 30, 2010				
Revenues from external customers	$ 1,132,123	$ 142,546	$ 35	$ 1,274,704
Intersegment revenues (eliminations)	83		(83)	
Revenues	1,132,206	142,546	(48)	1,274,704
Profit (loss)*	57,866	47,483	(16,723)	88,626
Income taxes (benefit)	21,174	17,616	(7,498)	31,292
Net income (loss)	36,692	29,867	(9,225)	57,334
Preferred stock dividends of subsidiaries	998		(52)	946
Net income (loss) for common stock	35,694	29,867	(9,173)	56,388
Assets (at June 30, 2010)	3,994,068	4,874,809	11,484	8,880,361
Three months ended June 30, 2009				
Revenues from external customers	$ 450,381	$ 75,499	$ 21	$ 525,901
Intersegment revenues (eliminations)	36		(36)	
Revenues	450,417	75,499	(15)	525,901
Profit (loss)*	24,666	5,482	(7,156)	22,992
Income taxes (benefit)	8,672	1,461	(3,093)	7,040
Net income (loss)	15,994	4,021	(4,063)	15,952
Preferred stock dividends of subsidiaries	499		(26)	473
Net income (loss) for common stock	15,495	4,021	(4,037)	15,479
Six months ended June 30, 2009				
Revenues from external customers	$ 912,142	$ 157,531	$ 25	$ 1,069,698
Intersegment revenues (eliminations)	72		(72)	
Revenues	912,214	157,531	(47)	1,069,698
Profit (loss)*	47,749	22,574	(15,279)	55,044
Income taxes (benefit)	17,124	7,671	(6,571)	18,224
Net income (loss)	30,625	14,903	(8,708)	36,820
Preferred stock dividends of subsidiaries	998		(52)	946
Net income (loss) for common stock	29,627	14,903	(8,656)	35,874
Assets (at December 31, 2009)	3,978,392	4,940,985	5,625	8,925,002

* Income (loss) before income taxes.

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 49.

4 • Bank subsidiary

Selected financial information

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

Consolidated Statements of Income Data (unaudited)

(in thousands)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Interest and dividend income				
Interest and fees on loans	$ 49,328	$ 55,363	$ 99,073	$ 113,455
Interest and dividends on investment and mortgage-related securities	3,646	7,143	6,963	14,819
	52,974	62,506	106,036	128,274
Interest expense				
Interest on deposit liabilities	3,852	9,902	8,275	21,467
Interest on other borrowings	1,418	2,241	2,844	5,505
	5,270	12,143	11,119	26,972
Net interest income	**47,704**	**50,363**	**94,917**	**101,302**
Provision for loan losses	990	13,500	6,349	21,800
Net interest income after provision for loan losses	**46,714**	**36,863**	**88,568**	**79,502**
Noninterest income				
Fee income on deposit liabilities	7,891	7,462	15,411	14,173
Fees from other financial services	6,649	6,443	13,063	12,362
Fee income on other financial products	1,735	1,628	3,260	2,672
Net losses on available-for-sale securities		(5,537)		(5,537)
Other income	2,383	2,997	4,776	5,587
	18,658	12,993	36,510	29,257
Noninterest expense				
Compensation and employee benefits	18,907	17,991	36,309	37,351
Occupancy	4,216	5,922	8,441	11,051
Data processing	4,564	3,481	8,902	6,668
Services	1,845	3,801	3,573	7,219
Equipment	1,640	2,540	3,349	5,330
Loss on early extinguishment of debt		60		101
Other expense	8,453	10,579	17,021	18,465
	39,625	44,374	77,595	86,185
Income before income taxes	**25,747**	**5,482**	**47,483**	**22,574**
Income taxes	9,616	1,461	17,616	7,671

Net income	**$**	**16,131**	**$**	**4,021**	**$**	**29,867**	**$**	**14,903**

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

Consolidated Balance Sheets Data (unaudited)

(in thousands)	June 30, 2010	December 31, 2009
Assets		
Cash and cash equivalents	$ 265,464	$ 425,896
Federal funds sold	794	1,479
Available-for-sale investment and mortgage-related securities	623,965	432,881
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,573,131	3,670,493
Other	231,501	230,282
Goodwill, net	82,190	82,190
	$ 4,874,809	$ 4,940,985
Liabilities and stockholder s equity		
Deposit liabilities noninterest-bearing	$ 824,004	$ 808,474
Deposit liabilities interest-bearing	3,177,530	3,250,286
Other borrowings	256,515	297,628
Other	109,458	92,129
	4,367,507	4,448,517
Common stock	330,218	329,439
Retained earnings	179,522	172,655
Accumulated other comprehensive loss, net of tax benefits	(2,438)	(9,626)
	507,302	492,468
	$ 4,874,809	$ 4,940,985

Other assets

(in thousands)	June 30, 2010	December 31, 2009
Bank-owned life insurance	$ 115,433	$ 113,433
Premises and equipment, net	56,671	54,428
Prepaid expenses	21,766	24,353
Accrued interest receivable	15,544	15,247
Mortgage-servicing rights	4,943	4,200
Real estate acquired in settlement of loans, net	3,764	3,959
Other	13,380	14,662
	$ 231,501	$ 230,282

Other liabilities

(in thousands)	June 30, 2010	December 31, 2009
Accrued expenses	$ 30,838	$ 17,270
Federal and state income taxes payable	28,596	19,141
Cashier s checks	25,788	26,877

Advance payments by borrowers		10,533		10,989
Other		13,703		17,852
	$	109,458	$	92,129

Other borrowings consisted of securities sold under agreements to repurchase and advances from the Federal Home Loan Bank (FHLB) of Seattle of $192 million and $65 million, respectively, as of June 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 June 30, 2010, ASB had 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:

	June 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	$ 307,328	$ 853	$ (3)	$ 308,178	$ 104,091	$ 109	$ (156)	$ 104,044
Mortgage-related securities FNMA, FHLMC and GNMA	291,424	11,379	(7)	302,796	319,642	7,967	(88)	327,521
Municipal bonds	12,972	19		12,991	1,300	16		1,316
	$ 611,724	$ 12,251	$ (10)	$ 623,965	$ 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 (%)**
June 30, 2010										
Investment securities federal agency obligations	$ 307,328	1.31	$ 10,000	0.30	$ 258,870	1.22	$ 38,458	2.15	$	
Mortgage-related securities FNMA, FHLMC and GNMA	291,424	3.81			4,177	2.29	120,318	3.79	166,929	3.87
Municipal bonds	12,972	3.14	500	1.92	800	2.50	11,116	3.24	556	3.00
	$ 611,724	2.54	$ 10,500	0.38	$ 263,847	1.24	$ 169,892	3.38	$ 167,485	3.87
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 three and six months ended June 30, 2009 of $5.5 million included impairment losses of $5.6 million, which consisted of $18.5 million of total other-than- temporary impairment losses, net of $12.9 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
June 30, 2010						
Investment securities federal agency obligations	$ (3)	$ 13,864	$	$	$ (3)	$ 13,864
Mortgage-related securities FNMA, FHLMC and GNMA	(7)	2,391			(7)	2,391
Municipal bonds						
	$ (10)	$ 16,255	$	$	$ (10)	$ 16,255
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 June 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, on 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 June 30, 2010 and 2009, ASB s assessment rate was 14 basis points of deposits, or $1.5 million.

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 six months of 2010, the utilities contributed $16.4 million and HEI contributed $0.4 million to their respective retirement benefit plans, compared to $15.7 million and $0.7 million, respectively, in the first six 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 June 30				Six months ended June 30			
	Pension benefits		Other benefits		Pension benefits		Other benefits	
(in thousands)	2010	2009	2010	2009	2010	2009	2010	2009
Service cost	$ 7,095	$ 6,388	$ 1,168	$ 1,171	$ 14,048	$ 12,729	$ 2,291	$ 2,227
Interest cost	16,093	15,514	2,652	2,838	32,133	31,052	5,336	5,685
Expected return on plan assets	(17,221)	(14,295)	(2,766)	(2,222)	(34,415)	(28,571)	(5,518)	(4,437)
Amortization of unrecognized transition obligation				784	1	1		1,569
Amortization of prior service cost (credit)	(97)	(95)	(52)	4	(194)	(188)	(104)	7
Recognized actuarial loss (gain)	1,791	3,964	(2)	107	3,507	7,933	(3)	223
Net periodic benefit cost	7,661	11,476	1,000	2,682	15,080	22,956	2,002	5,274
Impact of PUC D&Os	2,020	(4,107)	1,333	(407)	5,028	(8,198)	2,621	(732)
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 9,681	$ 7,369	$ 2,333	$ 2,275	$ 20,108	$ 14,758	$ 4,623	$ 4,542

The Company recorded retirement benefits expense of $19 million and $15 million in the first six months of 2010 and 2009, respectively, and charged the remaining amounts primarily to electric utility plant.

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

Defined contribution plan. On May 7, 2009, the ASB 401(k) Plan was spun-off from the existing Hawaiian Electric Industries Retirement Savings Plan (HEIRSP). The new Plan allows ASB employees the opportunity to defer a portion of their earnings on a pre-tax basis and receive a matching contribution (AmeriMatch) after one year with ASB. AmeriMatch equals 100% of the first 4% of the participant s eligible pay that is deferred to the plan and is fully vested. In addition, participants are eligible for an annual discretionary profit sharing contribution (AmeriShare) that is based on ASB s performance and achievement of its financial goals for the year. On May 15, 2009, ASB contributed $2.1 million to fund AmeriShare for the 2008 plan year. This AmeriShare contribution was allocated pro-rata to accounts of eligible participants based on a flat 4% percent of eligible pay. On March 17, 2010, ASB contributed $1.9 million to fund AmeriShare for the 2009 plan year. This contribution equated to 3.6% of eligible pay for eligible participants. For the first six months of 2010 and 2009, ASB s total expense for its employees participating in the HEIRSP and the new ASB 401(k) Plan combined was $1.9 million and $1.3 million, respectively. For the first six months of 2010 and 2009, ASB s cash contributions were $2.8 million and $3.0 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 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 June 30, 2010, 77,500 deferred shares were granted under the EIP.

Under the 1987 Stock Option and Incentive Plan, as amended (SOIP), grants and awards of 1.2 million shares of common stock (estimated based on assumptions, including LTIP awards at maximum levels and the use of the June 30, 2010 market price of shares as the price on the exercise/payment dates) were outstanding as of June 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, 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 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:

	Three months ended June 30		Six months ended June 30	
($ in millions)	**2010**	**2009**	**2010**	**2009**
Share-based compensation expense (1)	0.8		1.4	0.4
Income tax benefit	0.2		0.4	0.1

(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:

June 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	0.8	$ 17.96
2002	21.68	122,000	1.6	21.68
2003	20.49	123,500	2.4	20.49
	$ 17.96 21.68	309,500	1.8	$ 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 June 30, 2010, all NQSOs outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $1.7 million.

NQSO activity and statistics are summarized as follows:

	Three months ended June 30		**Six months ended June 30**	
($ in thousands, except prices)	**2010**	**2009**	**2010**	**2009**
Shares expired		1,000	2,000	1,000
Weighted-average exercise price		$ 17.61	$ 20.49	$ 17.61
Shares exercised	17,000		63,000	
Weighted-average exercise price	$ 20.34		$ 16.25	
Cash received from exercise	$ 346		$ 1,024	
Intrinsic value of shares exercised (1)	$ 76		$ 625	
Tax benefit realized for the deduction of exercises	$ 29		$ 243	

(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:

June 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	2.6	$	26.02
2005	26.18	312,000	3.2		26.18
	$26.02 26.18	462,000	3.0	$	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 June 30, 2010, all SARs outstanding were exercisable and had no intrinsic value.

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SARs activity and statistics are summarized as follows:

	Three months ended June 30		Six months ended June 30	
($ in thousands, except prices)	2010	2009	2010	2009
Shares forfeited				6,000
Weighted-average exercise price				$ 26.18
Shares expired	12,000	305,000	18,000	305,000
Weighted-average exercise price	$ 26.18	$ 26.10	$ 26.18	$ 26.10
Shares vested		228,000		228,000
Aggregate fair value of vested shares		$ 1,354		$ 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 six months ended June 30, 2009 a total of 3,143 dividend equivalent shares for SAR grants were distributed to SOIP participants. Section 409A, which amended the rules on deferred compensation, required the Company to change the way certain affected dividend equivalents are paid in order to avoid significant adverse tax consequences to the SOIP participants. Generally, dividend equivalents subject to Section 409A 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 June 30				Six months ended June 30			
	2010		2009		2010		2009	
	Shares	(1)	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, beginning of period	120,700	$ 25.48	138,500	$ 25.48	129,000	$ 25.50	160,500	$ 25.51
Granted								
Vested	(42,000)	26.30	(3,257)	24.60	(43,565)	26.29	(3,851)	24.52
Forfeited			(1,243)	25.49	(6,735)	25.75	(22,649)	25.74
Outstanding, end of period	78,700	$ 25.04	134,000	$ 25.50	78,700	$ 25.04	134,000	$ 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 second quarters of 2010 and 2009, total restricted stock vested had a fair value of $1.1 million and $80,000, respectively. For the six months ended June 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 $0.3 million and $58,000 for the first six months of 2010 and 2009, respectively.

As of June 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 1.5 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 June 30				Six months ended June 30			
	2010		2009		2010		2009	
	Shares	(1)	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, beginning of period	69,000	$ 16.99	70,500	$ 16.99	70,500	$ 16.99		$
Granted	77,500(3)	22.30			77,500	22.30	70,500(2)	16.99
Vested					(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 June 30, 2010, 77,500 deferred shares were outstanding under the EIP and 69,000 restricted stock units were outstanding under the SOIP.

For the six months ended June 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 June 30, 2010, there was $2.1 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 3.4 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 2 year averages (2011-2012).

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

	Three months ended June 30				Six months ended June 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								
Forfeited					(801)	14.85		
Outstanding, end of period	132,588	$ 20.42	36,198	$ 14.85	132,588	$ 20.42	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 June 30, 2010, there was $1.9 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 2.2 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 June 30				Six months ended June 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					(535)	16.99		
Outstanding, end of period	184,535	$ 18.69	24,131	$ 16.99	184,535	$ 18.69	24,131	$ 16.99

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

(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 June 30, 2010, there was $2.7 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 2.4 years.

7 • Interest rate swap agreements

In the second quarter of 2010, HEI utilized Forward Starting Swaps (FSS) to hedge against future interest rate fluctuations related to anticipated medium-term note issuances, thereby enabling HEI to better forecast its future interest expense. These agreements are designated as cash flow hedges and recorded on the balance sheet at fair value. 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.

In June 2010, HEI entered into multiple FSS with notional amounts totaling $125 million to hedge against interest rate fluctuations on debt securities anticipated to be issued by HEI in 2011. These FSS remove a portion of the interest rate variability on the $50 million and $100 million, respectively, of medium-term notes expected to be issued. The FSS terminate in January and June 2011 and entitle HEI to receive/(pay) the present value of the positive/(negative) difference between 3 month LIBOR and a fixed rate at termination applied to the notional amount over a five year period. The FSS are accounted for as cash flow hedges and have a negative fair value of $1.7 million as of June 30, 2010 (included in Other liabilities on the consolidated balance sheet). For the second quarter of 2010, the ineffective portion of the change in fair value was immaterial and the effective portion, or

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$1.0 million, net of tax benefits, was recorded in AOCI. A de minimis portion of the $1.0 million net loss in AOCI is expected to be reclassified to earnings during the next 12 months.

8 • Earnings per share (EPS)

For the three and six months ended June 30, 2010, under the two-class method of computing basic and diluted EPS, distributed earnings were $0.31 and $0.62 per share, respectively, and undistributed losses were nil and $0.01 per share, respectively, for both unvested restricted stock awards and unrestricted common stock. For the three and six months ended June 30, 2009, under the two-class method of computing basic and diluted EPS, distributed earnings were $0.31 and $0.62 per share, respectively, and undistributed losses were $0.14 and $0.23 per share, respectively, for both unvested restricted stock awards and unrestricted common stock.

As of June 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.

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 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.

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

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

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

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:

	June 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	$ 278,324	$ 278,324	$ 503,922	$ 503,922
Available-for-sale investment and mortgage-related securities	623,965	623,965	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	3,573,131	3,726,365	3,670,493	3,760,954
Financial liabilities				
Deposit liabilities	4,001,534	4,006,701	4,058,760	4,063,888
Short-term borrowings other than bank	55,012	55,012	41,989	41,989
Other bank borrowings	256,515	272,905	297,628	307,154
Long-term debt, net other than bank	1,364,879	1,361,253	1,364,815	1,336,250

Forward Starting Swaps	1,701	1,701		
Off-balance sheet items				
HECO-obligated preferred securities of trust subsidiary	50,000	50,500	50,000	48,480

As of June 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 $0.4 million and $0.2 million, respectively. As of June 30, 2010 and December 31, 2009, loans serviced by ASB for others had notional amounts of $657.2 million and $577.5 million and the estimated fair value of the servicing rights for such loans was $7.2 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

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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 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:

		Fair value measurements using	
(in thousands)	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
June 30, 2010			
Available-for-sale securities			
Mortgage-related securities-FNMA, FHLMC and GNMA	$	$ 302,796	$
Investment securities-federal agency obligation		308,178	
Municipal bonds		12,991	
	$	$ 623,965	$
Forward Starting Swaps	$	$ (1,701)	$
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 quarter of 2010, HECO s asset retirement obligation was adjusted (see Note 8, Fair value measurements of HECO Notes to Consolidated Financial Statements).

11 • Cash flows

Supplemental disclosures of cash flow information. For the six months ended June 30, 2010 and 2009, the Company paid interest (net of amounts capitalized and including bank interest) to non-affiliates amounting to $46 million and $52 million, respectively.

For the six months ended June 30, 2010 and 2009, the Company paid income taxes amounting to $44 million and $12 million, respectively. The increase in income taxes paid was primarily due to higher operating income in 2010 and additional tax deductions provided by bonus depreciation in 2009, which were not available in 2010.

Supplemental disclosures of noncash activities. Noncash increases in common stock for director and officer compensatory plans of the Company were $2.3 million and $1.2 million for the six months ended June 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 $11 million and $5 million for the first six 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.

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12 • Recent accounting pronouncements and interpretations

Variable interest entities. In June 2009, the Financial Accounting Standards Board 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.

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 June 30 2010	Three months ended June 30 2009	Six months ended June 30 2010	Six months ended June 30 2009
Operating revenues	**$ 582,094**	**$ 447,836**	**$ 1,128,806**	**$ 907,121**
Operating expenses				
Fuel oil	215,322	131,885	427,074	277,174
Purchased power	139,513	115,189	256,295	229,673
Other operation	60,254	63,181	119,498	125,578
Maintenance	32,223	29,431	59,276	55,594
Depreciation	38,649	36,425	77,291	72,849
Taxes, other than income taxes	54,170	41,975	105,961	87,710
Income taxes	11,113	8,727	22,154	17,271
	551,244	426,813	1,067,549	865,849
Operating income	**30,850**	**21,023**	**61,257**	**41,272**
Other income				
Allowance for equity funds used during construction	1,847	4,120	3,620	7,725
Other, net	372	2,468	1,613	4,836
	2,219	6,588	5,233	12,561
Interest and other charges				
Interest on long-term debt	14,383	11,945	28,766	23,857
Amortization of net bond premium and expense	726	682	1,393	1,357
Other interest charges	609	717	1,208	1,343
Allowance for borrowed funds used during construction	(790)	(1,727)	(1,569)	(3,349)
	14,928	11,617	29,798	23,208
Net income	**18,141**	**15,994**	**36,692**	**30,625**
Preferred stock dividends of subsidiaries	229	229	458	458
Net income attributable to HECO	**17,912**	**15,765**	**36,234**	**30,167**
Preferred stock dividends of HECO	270	270	540	540
Net income for common stock	**$ 17,642**	**$ 15,495**	**$ 35,694**	**$ 29,627**

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)	June 30, 2010	December 31, 2009
Assets		
Utility plant, at cost		
Land	$ 51,393	$ 52,530
Plant and equipment	4,800,278	4,696,257
Less accumulated depreciation	(1,900,466)	(1,848,416)
Construction in progress	98,231	132,980
Net utility plant	3,049,436	3,033,351
Current assets		
Cash and cash equivalents	10,683	73,578
Customer accounts receivable, net	142,028	133,286
Accrued unbilled revenues, net	90,773	84,276
Other accounts receivable, net	18,538	8,449
Fuel oil stock, at average cost	128,420	78,661
Materials and supplies, at average cost	36,780	35,908
Prepayments and other	16,000	16,201
Total current assets	443,222	430,359
Other long-term assets		
Regulatory assets	424,614	426,862
Unamortized debt expense	14,841	14,288
Other	61,955	73,532
Total other long-term assets	501,410	514,682
	$ 3,994,068	$ 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	385,652	385,659
Retained earnings	835,843	827,036
Accumulated other comprehensive income, net of income taxes	1,898	1,782
Common stock equity	1,315,324	1,306,408
Cumulative preferred stock not subject to mandatory redemption	34,293	34,293
Long-term debt, net	1,057,879	1,057,815
Total capitalization	2,407,496	2,398,516
Current liabilities		
Short-term borrowings nonaffiliates	14,100	
Accounts payable	138,539	132,711
Interest and preferred dividends payable	21,669	21,223
Taxes accrued	124,740	156,092
Other	49,268	48,192
Total current liabilities	348,316	358,218
Deferred credits and other liabilities		
Deferred income taxes	176,219	180,603
Regulatory liabilities	293,299	288,214
Unamortized tax credits	58,016	56,870
Retirement benefits liability	293,720	296,623
Other	90,952	77,804
Total deferred credits and other liabilities	912,206	900,114
Contributions in aid of construction	326,050	321,544
	$ 3,994,068	$ 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				35,694		35,694
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,155					1,813	1,813
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,080					(1,697)	(1,697)
Comprehensive income				35,694	116	35,810
Common stock dividends				(26,887)		(26,887)
Common stock issue expenses			(7)			(7)
Balance, June 30, 2010	**13,787**	**$ 91,931**	**$ 385,652**	**$ 835,843**	**$ 1,898**	**$ 1,315,324**
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				29,627		29,627
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $3,408					5,350	5,350
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $3,333					(5,233)	(5,233)
Comprehensive income				29,627	117	29,744
Common stock issue expenses			(4)			(4)
Common stock dividends				(21,135)		(21,135)
Balance, June 30, 2009	**12,806**	**$ 85,387**	**$ 299,210**	**$ 811,082**	**$ 1,768**	**$ 1,197,447**

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)

Six months ended June 30 (in thousands)	2010	2009
Cash flows from operating activities		
Net income	$ 36,692	$ 30,625
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	77,291	72,849
Other amortization	3,101	5,502
Changes in deferred income taxes	(4,522)	7,264
Changes in tax credits, net	1,685	(1,321)
Allowance for equity funds used during construction	(3,620)	(7,725)
Decrease in cash overdraft	(302)	
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	(18,258)	58,382
Decrease (increase) in accrued unbilled revenues	(6,497)	28,039
Decrease (increase) in fuel oil stock	(49,759)	22,383
Increase in materials and supplies	(872)	(540)
Increase in regulatory assets	(2,252)	(10,564)
Increase (decrease) in accounts payable	5,828	(12,881)
Changes in prepaid and accrued income and utility revenue taxes	(31,864)	(61,259)
Changes in other assets and liabilities	14,669	(3,542)
Net cash provided by operating activities	**21,320**	**127,212**
Cash flows from investing activities		
Capital expenditures	(78,511)	(174,473)
Contributions in aid of construction	9,430	4,917
Net cash used in investing activities	**(69,081)**	**(169,556)**
Cash flows from financing activities		
Common stock dividends	(26,887)	(21,135)
Preferred stock dividends of HECO and subsidiaries	(998)	(998)
Proceeds from issuance of long-term debt		3,168
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	14,100	59,054
Decrease in cash overdraft		(962)
Other	(1,349)	(8)
Net cash provided by (used in) financing activities	**(15,134)**	**39,119**
Net decrease in cash and cash equivalents	(62,895)	(3,225)
Cash and cash equivalents, beginning of period	73,578	6,901
Cash and cash equivalents, end of period	**$ 10,683**	**$ 3,676**

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 Report on SEC Form 10-Q for the quarter ended March 31, 2010.

In the opinion of HECO s management, the accompanying unaudited consolidated financial statements contain all material adjustments required by GAAP to present fairly the financial position of HECO and its subsidiaries as of June 30, 2010 and December 31, 2009 and the results of their operations for the three and six months ended June 30, 2010 and 2009 and their cash flows for the six months ended June 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.

In April 2010, management evaluated the impact of ASU 2009-04, Accounting for Redeemable Equity Instruments, and the provisions of the utilities $34 million of preferred stock that allowed preferred shareholders to potentially control the board if preferred dividends were not paid for four quarters, which could lead to the redemption of the preferred shares. This evaluation resulted in the movement of preferred stock of HECO and its subsidiaries on the consolidated balance sheet from stockholders equity to mezzanine equity and the removal of preferred stock from the consolidated statement of changes in stockholders equity for all prior periods presented, which changes were immaterial to the financial statements. There were no changes to previously reported consolidated operating income, net income and cash flows.

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 June 30, 2010 and December 31, 2009 each consisted of $51.5 million of 2004 Debentures;

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$50.0 million of 2004 Trust Preferred Securities; and $1.5 million of trust common securities. Trust III s income statements for the six months ended June 30, 2010 and 2009 each consisted of $1.7 million of interest income received from the 2004 Debentures; $1.6 million of distributions to holders of the Trust Preferred Securities; and $0.1 million of common dividends on the trust common securities to HECO. So long as the 2004 Trust Preferred Securities are outstanding, HECO is not entitled to receive any funds from Trust III other than pro-rata distributions, subject to certain subordination provisions, on the trust common securities. In the event of a default by HECO in the performance of its obligations under the 2004 Debentures or under its Guarantees, or in the event HECO, HELCO or MECO elect to defer payment of interest on any of their respective 2004 Debentures, then HECO will be subject to a number of restrictions, including a prohibition on the payment of dividends on its common stock.

Power purchase agreements (PPAs). As of June 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 six months ended June 30, 2010 totaled $256 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $69 million, $99 million, $28 million and $23 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 six months ended June 30, 2010 and 2009, HECO and its subsidiaries included approximately $100 million and $83 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 six months of 2010, HECO and its subsidiaries contributed $16.4 million to their retirement benefit plans, compared to $15.7 million in the first six 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 June 30				Six months ended June 30			
	Pension benefits		Other benefits		Pension benefits		Other benefits	
(in thousands)	2010	2009	2010	2009	2010	2009	2010	2009
Service cost	$ 6,772	$ 6,107	$ 1,131	$ 1,137	$ 13,382	$ 12,167	$ 2,219	$ 2,164
Interest cost	14,658	14,034	2,571	2,755	29,237	28,084	5,167	5,520
Expected return on plan assets	(15,353)	(12,693)	(2,728)	(2,183)	(30,677)	(25,366)	(5,443)	(4,361)
Amortization of unrecognized transition obligation			(2)	782			(4)	1,565
Amortization of prior service credit	(187)	(185)	(56)		(374)	(368)	(111)	
Recognized actuarial loss	1,767	3,673	1	103	3,452	7,344	4	217
Net periodic benefit cost	7,657	10,936	917	2,594	15,020	21,861	1,832	5,105
Impact of PUC D&Os	2,020	(4,107)	1,333	(407)	5,028	(8,198)	2,621	(732)
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 9,677	$ 6,829	$ 2,250	$ 2,187	$ 20,048	$ 13,663	$ 4,453	$ 4,373

HECO and its subsidiaries recorded retirement benefits expense of $19 million and $14 million for the first six months of 2010 and 2009, respectively. The electric utilities charged a portion of the net periodic benefit cost to plant.

5 • Commitments and contingencies

Fuel contracts and power purchase agreements. On December 2, 2009, HECO and Chevron Products Company, a division of Chevron USA, Inc. (Chevron) executed an amendment to their existing contract for the purchase/sale of low sulfur fuel oil. The amendment modified the pricing formula, which could result in higher prices. The amended agreement terminates on April 30, 2013. On January 28, 2010, the PUC approved the amendment on an interim basis, and allowed HECO to include the costs incurred under the amendment in its energy cost adjustment clause (ECAC), to the extent such costs are not recovered through HECO s base rates. The costs recovered as a result of the interim decision are not subject to retroactive disallowance, provided HECO complies with the remaining procedural schedule, which includes additional discovery by the Consumer Advocate, and there is no evidence of intentional misrepresentation or omission of facts by HECO or Chevron, or any other form of malfeasance.

On May 5, 2010, HECO and Tesoro Hawaii Corporation (Tesoro) executed a second amendment to their existing LSFO supply contract (LSFO contract), subject to PUC approval. The amendment modified the pricing formula, which could result in higher prices. It also reduced the minimum fuel volumes HECO is obligated to buy under the LSFO contract and reduced the maximum volumes Tesoro is obligated to sell HECO under the LSFO contract. The term of the amended agreement runs through April 30, 2013 and may automatically renew for annual terms thereafter unless earlier terminated by either party. On June 7, 2010, HECO submitted an application for PUC approval of the second amendment, such that the changes in fuel prices under the amendment would be included in HECO s ECAC, and included a request that the PUC approve the applicability of the amended pricing retroactive to January 1, 2010.

The energy charge for energy purchased from Kalaeloa under HECO s PPA with Kalaeloa is based, in part, on the price Kalaeloa pays Tesoro for fuel oil under a Facility Fuel Supply Contract (fuel contract) between them. Kalaeloa and Tesoro have negotiated a proposed amendment to the pricing formula in their fuel contract. The amendment could result in higher fuel prices for Kalaeloa. Kalaeloa has requested HECO s consent to the amendment. If, after review, HECO consents, HECO will seek PUC approval to include the costs incurred under the PPA as a result of the fuel contract amendment in HECO s ECAC.

Hawaii Clean Energy Initiative. In January 2008, the State of Hawaii (State or Hawaii) and the U.S. Department of Energy (DOE) signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative (HCEI) with the stated purpose of establishing a long-term partnership between the State and the DOE that will result in a fundamental and sustained transformation in the way in which energy is produced and energy resources are planned and used in the State.

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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 with the purpose of decreasing the State s dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation.

The parties recognize that the move toward a more renewable and distributed and intermittent power system will pose increased operating challenges to the utilities and that there is a need to assure that Hawaii preserves a stable electric grid to minimize disruption in service quality and reliability. They further recognize that Hawaii needs a system of utility regulation to transform the utilities from traditional sales-based companies to energy services companies while preserving financially sound utilities.

Many of the actions and programs included in the Energy Agreement require approval of the PUC in proceedings that need to be initiated by the PUC or the utilities.

Among the major provisions of the Energy Agreement and related actions most directly affecting HECO and its subsidiaries are the following:

Renewable energy and energy efficiency goals. The Energy Agreement provides for the parties to pursue an overall goal of providing 70% of Hawaii s electricity and ground transportation energy needs from clean energy sources, including renewable energy and energy efficiency, by 2030. The ground transportation energy needs included in this goal include a contemplated move in Hawaii to electrification of transportation and the use of electric utility capacity in off peak hours to recharge vehicles and batteries. To help achieve this goal, changes to the Hawaii Renewable Portfolio Standards (RPS) law were enacted in 2009 to require electric utilities to meet an RPS of 10%, 15%, 25% and 40% by December 31, 2010, 2015, 2020 and 2030, respectively. The PUC must evaluate the standards every five years, beginning in 2013, to determine whether the standards remain effective and achievable or should be revised. Under current RPS law, energy savings resulting from energy efficiency programs will not count toward the RPS from January 1, 2015.

In December 2008, the PUC approved a penalty of $20 for every megawatthour (MWh) that an electric utility is deficient under Hawaii s RPS law. However, this penalty may be reduced, in the PUC s discretion, due to events or circumstances that are outside an electric utility s reasonable control, to the extent the event or circumstance could not be reasonably foreseen and ameliorated. The utilities will be prohibited from recovering any RPS penalties through rates.

To help achieve the 70% clean energy goal, an Energy Efficiency Portfolio Standard (EEPS) was enacted as part of Act 155, Session Laws of Hawaii 2009, which provided that the PUC establish (1) the standards designed to achieve a reduction of 4,300 gigawatthours of electricity use statewide by 2030, which may be revised; (2) interim goals for electricity use reduction to be achieved by 2015, 2020 and 2025; and (3) incentives and penalties to encourage achievement of these goals, if needed. In March 2010, the PUC opened a new docket to examine establishing an EEPS for Hawaii.

Clean Energy Infrastructure Surcharge (CEIS)/ Renewable Energy Infrastructure Program (REIP) Surcharge. The Energy Agreement provides for the establishment of a CEIS to (1) expedite cost recovery (including expenses, depreciation and an allowed return on investment) for infrastructure that supports greater use of renewable energy or grid efficiency within the utility systems (such as advanced metering, energy storage, interconnections and interfaces); and (2) be used to recover costs stranded by clean energy initiatives. A REIP Surcharge, which replaces the CEIS, was approved by the PUC in December 2009. The utilities need to file for project approval and cost inclusion in the surcharge on a project-by-project basis. The costs of an approved REIP project will continue to be included in the surcharge until the remaining costs of the project are included in the revenue requirements of the utility in a general rate case, and the PUC approves recovery through base rates.

In May 2010, the PUC approved HECO s request to recover, via the REIP Surcharge, $2.4 million of payments for certain interconnection infrastructure for a wind farm project. The PUC also directed HECO to file proposed

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written standards on HECO s ability to offer to use the REIP Surcharge and the terms of such offer in its negotiations with renewable project developers. HECO filed such proposed standards in July 2010.

Renewable energy projects. HECO and its subsidiaries continue to negotiate with developers of currently 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. Utilizing resources such as the U.S. Department of Energy national laboratories, the parties have committed to work together to evaluate, assess and address the operational challenges for integrating such a large increment of wind into its grid system on Oahu. 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.

The State has agreed to seek, with HECO and/or developers reasonable assistance, federal grant or loan assistance to pay for the undersea cable system. If federal funding is unavailable, the State will employ its best effort to fund the undersea cable system through taxpayer and ratepayer sources. HECO is not obligated to fund any of the cost of the undersea cable system, however, if HECO funds any part of the cost to develop the cable system and assumes any ownership of the cable system, all reasonably incurred capital costs and expenses are intended to be recoverable through the REIP.

Feed-in tariff (FIT). The Energy Agreement includes support for the development of a FIT system with standardized purchase prices for renewable energy. On October 24, 2008, the PUC opened an investigative proceeding to examine the implementation of FITs. The utilities and Consumer Advocate were named as initial parties to the proceeding and 18 other parties were granted intervenor or participant status.

In September 2009, the PUC issued a decision and order (D&O) that sets forth general principles for the FIT, approved the FIT as a mechanism for the procurement of renewable resources and directed the parties to file a stipulated procedural schedule that governs tasks for implementing a FIT, including development of queuing and interconnection procedures, reliability standards and FIT rates. The D&O contemplates that, for the initial FIT, there will be rates for photovoltaic (PV), concentrated solar power, onshore wind, and in-line hydropower projects. Eligible project sizes vary depending on which island the project is being sited on. On Oahu the FIT will differentiate between smaller projects up to 20 kilowatts (kW) in size (Tier 1), projects greater than 20 kW and up to 500 kW (Tier 2), and projects greater than 500 kW and up to 5 MW (Tier 3). On Maui and the island of Hawaii, Tier 1 FIT will be for projects up to 20 kW, Tier 2 FIT will be for projects greater than 20 kW and up to 250 kW, and Tier 3 FIT will be for projects greater than 250 kW and up to 2 MW. There will also be a baseline FIT rate to encourage other renewable energy technologies. FIT rates will be based on the project cost and reasonable profit of a typical project. The rates will be differentiated by technology or resource, project size, and interconnection costs; and will be levelized. The FIT program will be re-examined two years after it first becomes effective and every three years thereafter.

Filings of proposed FIT rates and contracts, queuing and interconnection procedures and reliability standards were made to the PUC in the first four months of 2010. The reliability standards filing identified the need to further evaluate technical renewable integration issues on the HELCO and MECO systems in order to implement FIT. The timing of implementing FIT on each island will depend on the PUC s consideration of these matters.

Net energy metering (NEM). Hawaii s NEM law requires the utilities to offer net metering of energy to eligible customer generators (i.e., a customer generator may receive credit for kilowatthours (KWHs) generated and exported to the grid up to the amount of KWHs used), subject to PUC-approved caps on the maximum capacity of customer generators and percentage of electric system penetration. Eligibility is limited to several renewable energy technologies with a generator size limit of 100 kW.

The Energy Agreement provided that system-wide caps on NEM should be removed after implementation of the FITs. Instead, all DG interconnections, including net metered systems, should be limited on a per-circuit basis to no more than 15% of peak circuit demand, to encourage the development of more cost effective distributed resources while still maintaining safe, reliable service.

In December 2008, HELCO, MECO and the Consumer Advocate filed stipulations to increase their NEM system caps from 1% to 3% of system peak demand (among other changes) and the PUC approved the proposed caps. The PUC directed the utilities and Consumer Advocate to file a proposed plan to address the provisions regarding NEM in the Energy Agreement, which plans were filed in August 2009. In January 2010, a stipulated agreement between the utilities and the Consumer Advocate was filed with the PUC that proposed the removal of the present system-wide cap with the adoption of revised interconnection standards to ensure ongoing reliability and safety, as well as the establishment of Reliability Standards. The proposal, which is pending PUC approval, included adoption of a 15% per-circuit distribution generation trigger for conducting further circuit-level impact studies; and removal of individual NEM program caps in favor of more overall system-wide assessments. In March 2010, MECO notified the PUC of its plans to raise the NEM system caps from 3% to 4% of system peak demand and filed revised tariff sheets effective in April 2010. Also, in April 2010, HELCO filed a similar notification regarding increasing its system caps to 4% of system peak demand, along with revised tariff sheets.

Decoupling rates from sales. In recognition of the need to recover the infrastructure and other investments required to support significantly increased levels of renewable energy and to eliminate the potential conflict between encouraging energy efficiency and conservation and lower sales revenues, the parties to the Energy Agreement agreed that it is appropriate to adopt a regulatory rate-making model under which the utilities revenues would be decoupled from KWH sales (similar to what has occurred in California).

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

The purpose of the RBA is to completely remove the linkage between sales and revenues, in order to encourage utility support for energy efficiency and distributed renewable resources. The RBA captures the difference between the target revenue requirement, consisting of both the revenue approved in the utility s last rate case and any RAM revenues, and actual billed revenues being collected, and adjusts rates (through an adjustment clause) to make up the difference.

The RAM is designed to re-determine annual utility authorized base revenue levels through the use of updated actual financial data and cost indices, thus providing for conservatively calculated changes in the utility s costs to provide service.

The earnings sharing mechanism in the RAM allows the utility s customers to benefit when utility earnings are above the utility s authorized return on equity.

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. Other parties commented on, but did not object to, the joint proposed final D&O. A final D&O is pending.

ECAC. The Energy Agreement confirms that the existing ECAC will continue, subject to periodic review by the PUC. As part of that review, the parties agree that the PUC will examine whether there are renewable energy projects from which the utilities should have, but did not, purchase energy or whether alternate fuel purchase strategies were appropriately used or not used.

Purchased power surcharge. Pursuant to the Energy Agreement, with PUC approval, a separate surcharge would be established to allow the utilities to pass through all reasonably incurred purchased power costs. In December 2008, HECO filed updates to its 2009 test year rate case, which proposed the establishment of a purchased power adjustment clause to recover non-energy purchased power costs approved by the PUC, which

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are currently recovered through base rates, with the purchased power adjustment clause to be adjusted monthly and reconciled quarterly. In their 2010 test year rate cases, MECO and HELCO each proposed the same purchased power adjustment clause as HECO.

Other initiatives. The Energy Agreement includes a number of other undertakings intended to accomplish the purposes and goals of the HCEI, subject to PUC approval, including: (a) supporting the development and use of renewable biofuels; (b) promoting greater use of solar energy; (c) 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; (d) improving and expanding load management and demand response programs that allow the utilities to control customer loads to improve grid reliability and cost management; (e) 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; (f) supporting prudent and cost effective investments in smart grid technologies, which become even more important as wind and solar generation is added to the grid; (g) delinking prices paid under all new renewable energy contracts from oil prices; and (h) exploring the possibility of establishing lifeline rates designed to provide a cap on rates for those who are unable to pay the full cost of electricity (which the utilities have proposed in their Lifeline Rate Program for qualified, low-income customers submitted for PUC approval in April 2009).

Interim increases. As of June 30, 2010, HECO and its subsidiaries had recognized $367 million of revenues with respect to interim orders ($362 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 the PUC disallows 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).

CIP CT-1 and transmission line. HECO has built a 110 MW simple cycle combustion turbine (CT) generating unit at CIP and has 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 CIP CT-1 and related transmission improvements.

As of June 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 during construction (AFUDC)). HECO is seeking to recover actual project costs in excess of the $163 million estimate included in HECO s 2009 test year rate case in its 2011 test year rate case. Management believes no adjustment to project costs is required as of June 30, 2010. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred.

East Oahu Transmission Project (EOTP). HECO had planned a project to construct a partially underground 138 kV line in order to close the gap between the southern and northern transmission corridors on Oahu and provide a third 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.

HECO continued to believe that the proposed reliability project was needed and, in 2003, filed an application with the PUC requesting approval to commit funds for a revised 46 kV system and a modified route, none of which is in conservation district lands.

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In October 2007, the PUC issued a final D&O approving HECO s request to expend funds for the EOTP (then estimated at $56 million - $42 million for Phase 1 and $14 million for Phase 2), but stating 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.

As a result of higher than estimated construction costs, an increase in the cost of materials and the overall delay in the project, Phase 1 is currently estimated to cost $57 million (including planning costs incurred prior to the 2002 denial of the permit of $12 million and AFUDC). The first phase was placed in service on June 29, 2010. For the second phase, after reviewing the updated cost and other technologies, in April 2010, HECO proposed an alternative design, subject to PUC approval, that should result in faster implementation and a lower cost (when compared to the updated cost for Phase 2, as originally planned). The alternative involves the use of smart grid technology to accomplish approximately the same operational benefits as the original design and it has been awarded partial funding through the Smart Grid Investment Grant Program of the American Recovery and Reinvestment Act of 2009 (ARRA). The alternative is estimated to cost approximately $10 million (total cost of $15 million less ARRA funding of $5 million) and is projected to be completed in 2012.

As of June 30, 2010, the accumulated costs recorded for the EOTP amounted to $59 million ($57 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) $23 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 June 30, 2010. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

HELCO generating units. In 1991, HELCO began planning to meet increased demand for electricity forecast for 1994. 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 January 1994, the PUC approved expenditures for CT-4. In 1995, the PUC allowed HELCO to pursue construction of and commit expenditures for CT-5 and ST-7, but noted that such costs are not to be included in rate base until the project is installed and is used and useful for utility purposes.

In March 2007, HELCO and the Consumer Advocate reached a settlement of the issues in the 2006 rate case proceeding, under which settlement HELCO agreed to write off approximately $12 million of the costs relating to CT-4 and CT-5, resulting in an after-tax charge to net income of $7 million. In April 2007, the PUC issued an interim D&O granting HELCO a 7.58% increase in rates, which D&O reflected the agreement to write off $12 million of the CT-4 and CT-5 costs.

On June 22, 2009, ST-7 was placed into service. As of June 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 HELCO s 2010 test year rate case.

Management believes that no further adjustment to project costs is required at June 30, 2010. However, if it becomes probable that the PUC will disallow for rate-making purposes additional CT-4 and CT-5 costs in its final D&O in HELCO s 2006 rate case or disallow any ST-7 costs in HELCO s 2010 rate case, HELCO will be required to record an additional write-off.

Customer Information System (CIS) Project. In August 2004, HECO, HELCO and MECO filed a joint application with the PUC for approval of the accounting treatment and recovery of certain costs related to acquiring and implementing a new CIS that would have substantially greater capabilities and features than the existing system, enabling the utilities to enhance their operations. In May 2005, the PUC approved the utilities request to (i) expend the then-estimated amount of $20.4 million for the 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.

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Following a competitive bidding process, HECO signed a contract with Peace Software US Inc. (Peace) in March 2006 to have Peace develop, deliver and implement the new CIS (implementation contract), with a transition to the new CIS originally scheduled to occur in February 2008. The transition did not occur as scheduled. In June 2008, HECO notified Peace that HECO considered Peace to be in material breach of the implementation contract. In August 2009, Peace provided HECO a notice of termination of the implementation contract and filed a lawsuit against HECO in the Hawaii United States District Court alleging, among other things, that HECO breached the contract by not paying amounts due. In June 2010, the parties executed a confidential release and settlement agreement resolving all claims in the litigation, and based on the agreement, the District Court entered an order dismissing with prejudice all claims in the litigation.

In June 2010, HECO contracted with a new CIS software vendor, SAP America, Inc. (SAP), following a competitive bidding process. The CIS Project will continue with HECO s selection of a system integrator expected to be made before the end of the third quarter of 2010.

Following resolution of the litigation and contracting with SAP as noted above, and related adjustments*,* as of June 30, 2010, the accumulated deferred and capital costs recorded for the CIS amounted to $15 million. Management believes no adjustment to project costs is required as of June 30, 2010. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

*HCEI projects***.** While much of the renewable energy infrastructure contemplated by the Energy Agreement will be developed by others (e.g., wind plant developments on Molokai and Lanai would be owned by a third-party developer, and the undersea cable system to bring the power generated by the wind plants to Oahu is currently planned to be owned by the State), the utilities may be making substantial investments in related infrastructure. In the Energy Agreement, the State agreed to support, facilitate and help expedite renewable projects, including expediting permitting processes.

In July 2009, HECO filed an application for the recovery of Big Wind Implementation Studies costs through the REIP Surcharge, which asked the PUC to approve the deferral and recovery of costs for studies and analyses needed to integrate large amounts of wind-generated renewable energy potentially located on the islands of Molokai and Lanai to the Oahu electric grid. On December 11, 2009, the PUC issued a D&O that allows HECO to defer costs for the Big Wind Implementation Studies for later review for prudence and reasonableness, but refrained from making any decision as to the specific recovery mechanism or the terms of any recovery mechanism (e.g., amortization period or carrying treatment).

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, HECO and its subsidiaries may be required to incur material levels of 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.

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

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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 area. The U.S. Environmental Protection Agency (EPA) became involved in the investigation in June 2000. Some 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. The Participating Parties will implement remedial design elements as they are approved by the DOH. A HECO investigation of its operations in the Iwilei Unit in 2003 and subsequent maintenance and inspections have confirmed that its facilities are not releasing petroleum.

Through June 30, 2010, HECO has accrued a total of $3.3 million for the estimated HECO share of costs for continuing investigative work, remedial activities and monitoring for the Iwilei unit. As of June 30, 2010, the remaining accrual (amounts expensed less amounts expended) for the Iwilei unit was $1.4 million. Because (1) the full scope of work remains to be determined, (2) the final cost allocation method among the PRPs has not yet been established and (3) management cannot estimate the costs to be incurred (if any) for the sites other than the Iwilei unit (such as its Honolulu power plant located in the Downtown unit of the Honolulu Harbor site), the cost estimate may be subject to significant change and additional material costs may be incurred.

Regional Haze Rule amendments. In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule that require emission controls known as best available retrofit technology (BART) for industrial facilities emitting air pollutants that reduce visibility in National Parks by causing or contributing to regional haze.

In May 2010, the EPA notified HELCO that it has determined that emissions from the Hill Power Plant decrease the visibility at Hawaii Volcanoes National Park and Haleakala National Park and requested a BART analysis by October 27, 2010. The EPA also advised that it plans to evaluate HELCO s Puna Power Plant and Shipman Power Plant emissions.

Also in May 2010, the EPA notified MECO that it has determined that emissions from the Kahului Generation Station cause or contribute to haze at Haleakala National Park and requested a regional haze analysis by September 21, 2010.

If any of HELCO or MECO s generating units are ultimately required to meet BART emission limits, the resulting capital and operation and maintenance costs could be significant.

Hazardous Air Pollutant (HAP) Control Steam Electric Generating Units. The EPA is required to issue Maximum Achievable Control Technology (MACT) standards for coal-fired and oil-fired electric generating unit (EGU) HAP emissions by November 16, 2011.

Depending on the MACT standards issued (and the outcome of a potential challenge that the EPA inappropriately included oil-fired EGUs initially), costs to comply with the standards could be significant.

Hazardous Air Pollutant (HAP) Control Industrial, Commercial and Institutional Boilers. In June 2010, the EPA issued rules governing HAP from industrial, commercial and institutional boilers at area sources of HAP. The rules apply to steam generating units operated by the utilities that do not qualify as EGUs. For such units, the rules require control of carbon monoxide emissions above a certain standard, installation of continuous emission monitoring systems, and institution of work practices designed to increase efficiency and thereby reduce HAP emissions. Management is evaluating the impacts of the rules, including capital expenditures and other compliance costs, which costs could be significant.

HAP Control Reciprocating Internal Combustion Engines (RICE). On March 3, 2010, the Federal Register published the EPA s final MACT standards that regulate HAPs from certain existing diesel compression ignition

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engines (Compression Ignition RICE), with final compliance by May 3, 2013. The EPA announced that it will also issue final MACT standards for certain gasoline and propane spark ignition engines (Spark Ignition RICE) by August 10, 2010. The Compression Ignition RICE MACT regulations require installation of pollution control devices on approximately 80 RICE at the utilities facilities. Approximately 20 of the utilities Compression Ignition RICE are required to implement only specified maintenance practices. Management is evaluating the impacts of the final Compression Ignition RICE rule, including capital expenditures and other compliance costs, which costs could be significant, and is also assessing the potential impacts of the proposed Spark Ignition RICE requirements.

Clean Water Act. Section 316(b) of the federal Clean Water Act requires that the EPA ensure that existing power plant cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. Because it is unclear what form the EPA s cooling water intake structure regulations will take, management is unable to predict which compliance options, some of which could entail significant capital expenditures, will be applicable to its facilities. When issued, the applicable final cooling water intake requirements will be incorporated into the National Pollutant Discharge Elimination System permits governing HECO s Kahe, Waiau and Honolulu Power Plants.

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 of Hawaii and 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. It also establishes a task force, comprised of representatives of state government, business, the University of Hawaii and environmental groups, which is charged with preparing a work plan and regulatory approach for implementing the maximum practically and technically feasible and cost-effective reductions in greenhouse gas emissions to achieve 1990 statewide GHG emission levels. The electric utilities are participating in the Task Force, 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 the work plan, which was submitted to the Hawaii Legislature in December 2009. The Task Force also unanimously recommended that the work plan include the HCEI as a means to meet the Act 234 GHG emission reduction goals, though costs and funding mechanisms would need further exploration and consideration. (For a discussion of the HCEI, see Hawaii Clean Energy Initiative above.) 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. The 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.

Since 2007, when the U.S. Supreme Court ruled in Massachusetts v. EPA, that the EPA has the authority to regulate GHG emissions from motor vehicles under the CAA, the EPA has accelerated rulemaking addressing GHG emissions from both mobile and stationary sources. In April 2009, the EPA proposed making 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. On September 22, 2009, the EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule, which requires that sources above certain threshold levels monitor and report GHG emissions beginning in 2010.

In addition, the Prevention of Significant Deterioration (PSD) permit program of the CAA applies to any pollutant that is subject to regulation under the CAA. The PSD program applies to designated air pollutants from new or modified stationary sources, such as utility electrical generation units. Currently, the PSD program does not apply to

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GHGs. However, 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 it is the date the federal GHG emission standards for motor vehicles (Tailpipe Rule) takes effect (i.e., it is the date the automobile industry is first required to demonstrate compliance with the Tailpipe Rule).

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 under 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. HECO seeks to identify and support viable technology for electricity production that will increase energy efficiency and reduce or eliminate GHG emissions, including taking actions in the Energy Agreement under the HCEI. Since the specific reductions the electric utilities would have to meet under GHG reduction legislation and rule-making remain unclear, 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 global warming cannot be determined with any certainty, global warming 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 and financial condition 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 mainland, interconnected systems. Although a major natural disaster could have severe financial implications, such risks have existed since the Company s inception. The Company makes a concerted effort to consider such physical risks in the design, construction and operation of its facilities, and 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. In January 2007, HECO and MECO agreed to form a venture with BlueEarth Biofuels LLC (BlueEarth) to develop a biodiesel production facility on MECO property on the island of Maui. BlueEarth Maui Biodiesel LLC (BlueEarth Maui), a joint venture to pursue biodiesel development, was formed in early 2008 between BlueEarth and Uluwehiokama Biofuels Corp. (UBC), a non-regulated subsidiary of HECO. In February 2008, an Operating Agreement and an Investment Agreement were executed between BlueEarth and UBC, under

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which UBC invested $400,000 in BlueEarth Maui in exchange for a minority ownership interest. MECO began negotiating with BlueEarth Maui for a fuel purchase contract for biodiesel to be used in existing diesel-fired units at MECO s Maalaea plant. However, negotiations for the biodiesel supply contract stalled based on an inability to reach agreement on various financial and risk allocation issues. In October 2008, BlueEarth filed a civil action in federal district court in Texas 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. In April 2009, the venue of the action was transferred to Hawaii. A trial date has been scheduled for April 2011. Work on the project was suspended because the litigation was filed. Although HECO remains committed to supporting development of renewable fuels production, because of the filing of the litigation and other factors, HECO and MECO now consider the project terminated and UBC s investment in the venture was written off in 2009.

Apollo Energy Corporation/Tawhiri Power LLC. HELCO purchases energy generated at the Kamao a wind farm pursuant to the Restated and Amended PPA for As-Available Energy (the RAC) dated October 13, 2004 between HELCO and Apollo Energy Corporation (Apollo), later assigned to Apollo s affiliate, Tawhiri Power LLC (Tawhiri). The maximum allowed output of the wind farm is 20.5 MW.

In June 2010, HELCO and Tawhiri participated in an arbitration relating to disputes surrounding HELCO s ownership and possessory interest in the switching station and reimbursement of certain interconnection costs. On July 20, 2010, the arbitration panel issued an interim award finding a breach of the RAC by Tawhiri with respect to its failure to transfer to HELCO title to the switching station and the rights to the land upon which the switching station was constructed. The panel ordered Tawhiri to execute HELCO s form of Bill of Sale to transfer ownership of the switching station and for the parties to work together to obtain for HELCO a lease from the landowner for the land occupied by the switching station. The panel is reserving ruling on the issue whether the breaches are material, and on claims for construction costs and attorneys fees until the final award and order is issued. The parties also have disputes regarding reconciliation of transmission line losses, which have not yet proceeded to arbitration.

Asset retirement obligation. In July 2009, HECO hired an industrial hygienist to conduct an inspection at HECO s Honolulu power plant to determine the extent of asbestos and lead-based paint at a non-operating, sealed and vacant portion of the plant. The inspection indicated that retired Generating Units Nos. 5 and 7 at the plant were now deteriorating, and the industrial hygienist recommended removing the asbestos-containing materials and lead-based paint. Based on prior assessments, HECO believed the timing of the removal of asbestos and lead-based paint was not 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. In accordance with accounting principles for asset retirement and environmental obligations, HECO recorded an asset retirement obligation in September 2009. In the second quarter of 2010, HECO s asset retirement obligation was increased by $11 million to $35 million due to an increase in estimated removal and abatement costs.

Collective bargaining agreements. As of June 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.

Limited insurance. HECO and its subsidiaries purchase insurance to protect themselves against loss or damage to their properties against claims made by third-parties and employees. However, the protection provided by such insurance is limited in significant respects and, in some instances, there is no coverage. HECO, HELCO and MECO s overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have a replacement value roughly estimated at $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

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costs and revenues lost from business interruption, their results of operations, financial condition and liquidity could be materially adversely impacted. Also, certain insurance has substantial deductibles , limits on the maximum amounts that may be recovered and exclusions or limitations of coverage for claims related to certain perils. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business, each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, HECO, HELCO and MECO could incur losses in amounts that would have a material adverse effect on their results of operations, financial condition and liquidity.

6 • Cash flows

Supplemental disclosures of cash flow information. For the six months ended June 30, 2010 and 2009, HECO and its subsidiaries paid interest amounting to $28 million and $21 million, respectively.

For the six months ended June 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 additional tax deductions provided by bonus depreciation in 2009, which were not available in 2010.

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 $3.6 million and $7.7 million for the six months ended June 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.

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 and 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 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.

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

	June 30, 2010		December 31, 2009	
(in thousands)	Carrying amount	Estimated fair value	Carrying amount	Estimated fair value
Financial assets				
Cash and cash equivalents	$ 10,683	$ 10,683	$ 73,578	$ 73,578
Financial liabilities				
Short-term borrowings from nonaffiliates	14,100	14,100		
Long-term debt, net, including amounts due within one year	1,057,879	1,043,903	1,057,815	1,018,900
Off-balance sheet item				
HECO-obligated preferred securities of trust subsidiary	50,000	50,500	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. 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.

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

(in thousands)	Three months ended June 30 2010	2009	Six months ended June 30 2010	2009
Operating income from regulated and nonregulated activities before income taxes (per HEI consolidated statements of income)	$ 41,435	$ 32,163	$ 84,044	$ 63,232
Deduct:				
Income taxes on regulated activities	(11,113)	(8,727)	(22,154)	(17,271)
Revenues from nonregulated activities	(2,001)	(2,581)	(3,400)	(5,093)
Add: Expenses from nonregulated activities	2,529	168	2,767	404
Operating income from regulated activities after income taxes (per HECO consolidated statements of income)	$ 30,850	$ 21,023	$ 61,257	$ 41,272

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11 • Subsequent event

HECO 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 methodology as proposed by HECO in its 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 annual interim rate increases of $77.5 million granted by the PUC in HECO s 2007 test year rate case and $73.8 million granted by the PUC in HECO s 2009 test year rate case, which are subject to final decisions from the PUC, and are subject to refund with interest if and to the extent that the final decisions provide 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 improvements and higher operation and maintenance costs required to maintain and improve system reliability.

MECO 2007 test year rate case. In February 2007, MECO filed a request for a general rate increase. In December 2007, MECO and the Consumer Advocate reached a settlement of all the revenue requirement issues in this rate case, and the PUC issued an interim D&O based on the settlement agreement granting MECO an increase of $13.2 million in annual revenues, or 3.7%, based on a 10.7% return on average common equity and an 8.67% return on a $383 million rate base. On July 30, 2010, the PUC issued a final D&O in the rate case confirming the December 2007 interim D&O rate increase.

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.

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 temporary approval of new depreciation rates and methodology proposed by MECO in its separate depreciation proceeding.

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.

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12 • 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.

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Three months ended June 30, 2010

(in thousands)	**HECO**	**HELCO**	**MECO**	**RHI**	**UBC**	**Reclassifications and eliminations**	**HECO Consolidated**
Operating revenues	$ 407,566	91,443	83,085				$ 582,094
Operating expenses							
Fuel oil	150,121	23,153	42,048				215,322
Purchased power	104,693	27,763	7,057				139,513
Other operation	44,220	8,232	7,802				60,254
Maintenance	18,566	7,915	5,742				32,223
Depreciation	21,912	9,127	7,610				38,649
Taxes, other than income taxes	37,834	8,509	7,827				54,170
Income taxes	8,847	1,395	871				11,113
	386,193	86,094	78,957				551,244
Operating income	21,373	5,349	4,128				30,850
Other income							
Allowance for equity funds used during construction	1,599	106	142				1,847
Equity in earnings of subsidiaries	3,426					(3,426)	
Other, net	890	140	(629)	(2)	(5)	(22)	372
	5,915	246	(487)	(2)	(5)	(3,448)	2,219
Interest and other charges							
Interest on long-term debt	9,131	2,984	2,268				14,383
Amortization of net bond premium and expense	484	118	124				726
Other interest charges	441	95	95			(22)	609
	(680)	(53)	(57)				(790)

Allowance for borrowed funds used during construction							
	9,376	3,144	2,430			(22)	14,928
Net income (loss)	17,912	2,451	1,211	(2)	(5)	(3,426)	18,141
Preferred stock dividend of subsidiaries		133	96				229
Net income (loss) attributable to HECO	17,912	2,318	1,115	(2)	(5)	(3,426)	17,912
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 17,642	2,318	1,115	(2)	(5)	(3,426)	$ 17,642

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Three months ended June 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Operating revenues	$ 300,395	79,674	67,767				$ 447,836
Operating expenses							
Fuel oil	86,808	15,762	29,315				131,885
Purchased power	84,329	26,731	4,129				115,189
Other operation	44,644	8,718	9,819				63,181
Maintenance	17,448	5,696	6,287				29,431
Depreciation	20,798	8,250	7,377				36,425
Taxes, other than income taxes	28,273	7,410	6,292				41,975
Income taxes	5,690	2,290	747				8,727
	287,990	74,857	63,966				426,813
Operating income	12,405	4,817	3,801				21,023
Other income							
Allowance for equity funds used during construction	3,176	767	177				4,120
Equity in earnings of subsidiaries	5,249					(5,249)	
Other, net	2,169	370	116	(1)	(6)	(180)	2,468
	10,594	1,137	293	(1)	(6)	(5,429)	6,588
Interest and other charges							
Interest on long-term debt	7,668	2,009	2,268				11,945
Amortization of net bond premium and expense	402	159	121				682
Other interest charges	536	242	119			(180)	717
Allowance for borrowed funds used during construction	(1,372)	(282)	(73)				(1,727)
	7,234	2,128	2,435			(180)	11,617
Net income (loss)	15,765	3,826	1,659	(1)	(6)	(5,249)	15,994
Preferred stock dividend of subsidiaries		133	96				229
Net income (loss) attributable to HECO	15,765	3,693	1,563	(1)	(6)	(5,249)	15,765
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 15,495	3,693	1,563	(1)	(6)	(5,249)	$ 15,495

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Six months ended June 30, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Operating revenues	$ 783,670	180,475	164,661				$ 1,128,806
Operating expenses							
Fuel oil	296,463	46,632	83,979				427,074
Purchased power	190,554	53,465	12,276				256,295
Other operation	85,846	17,249	16,403				119,498
Maintenance	35,640	11,310	12,326				59,276
Depreciation	43,825	18,253	15,213				77,291
Taxes, other than income taxes	73,557	16,837	15,567				105,961
Income taxes	16,752	4,042	1,360				22,154
	742,637	167,788	157,124				1,067,549
Operating income	41,033	12,687	7,537				61,257
Other income							
Allowance for equity funds used during construction	3,158	201	261				3,620
Equity in earnings of subsidiaries	8,719					(8,719)	
Other, net	2,004	255	(584)	(4)	(10)	(48)	1,613
	13,881	456	(323)	(4)	(10)	(8,767)	5,233
Interest and other charges							
Interest on long-term debt	18,261	5,969	4,536				28,766
Amortization of net bond premium and expense	917	235	241				1,393
Other interest charges	866	196	194			(48)	1,208
Allowance for borrowed funds used during construction	(1,364)	(102)	(103)				(1,569)
	18,680	6,298	4,868			(48)	29,798
Net income (loss)	36,234	6,845	2,346	(4)	(10)	(8,719)	36,692
Preferred stock dividend of subsidiaries		267	191				458
Net income (loss) attributable to HECO	36,234	6,578	2,155	(4)	(10)	(8,719)	36,234
Preferred stock dividends of HECO	540						540
Net income (loss) for common stock	$ 35,694	6,578	2,155	(4)	(10)	(8,719)	$ 35,694

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Six months ended June 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Operating revenues	$ 605,856	164,305	136,960				$ 907,121
Operating expenses							
Fuel oil	185,739	31,526	59,909				277,174
Purchased power	160,174	60,138	9,361				229,673
Other operation	87,720	18,712	19,146				125,578
Maintenance	34,106	11,634	9,854				55,594
Depreciation	41,595	16,501	14,753				72,849
Taxes, other than income taxes	58,956	15,656	13,098				87,710
Income taxes	11,919	3,140	2,212				17,271
	580,209	157,307	128,333				865,849
Operating income	25,647	6,998	8,627				41,272
Other income							
Allowance for equity funds used during construction	5,878	1,509	338				7,725
Equity in earnings of subsidiaries	9,209					(9,209)	
Other, net	4,047	939	197	(8)	(13)	(326)	4,836
	19,134	2,448	535	(8)	(13)	(9,535)	12,561
Interest and other charges							
Interest on long-term debt	15,336	3,985	4,536				23,857
Amortization of net bond premium and expense	805	310	242				1,357
Other interest charges	1,013	449	207			(326)	1,343
Allowance for borrowed funds used during construction	(2,540)	(670)	(139)				(3,349)
	14,614	4,074	4,846			(326)	23,208
Net income (loss)	30,167	5,372	4,316	(8)	(13)	(9,209)	30,625
Preferred stock dividend of subsidiaries		267	191				458
Net income (loss) attributable to HECO	30,167	5,105	4,125	(8)	(13)	(9,209)	30,167
Preferred stock dividends of HECO	540						540
Net income (loss) for common stock	$ 29,627	5,105	4,125	(8)	(13)	(9,209)	$ 29,627

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

June 30, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Assets							
Utility plant, at cost							
Land	$ 43,270	5,108	3,015				$ 51,393
Plant and equipment	2,926,236	999,803	874,239				4,800,278
Less accumulated depreciation	(1,106,484)	(392,764)	(401,218)				(1,900,466)
Construction in progress	74,421	13,705	10,105				98,231
Net utility plant	1,937,443	625,852	486,141				3,049,436
Investment in wholly owned subsidiaries, at equity	462,264					(462,264)	
Current assets							
Cash and cash equivalents	4,556	4,117	1,908	92	10		10,683
Advances to affiliates	14,850		9,000			(23,850)	
Customer accounts receivable, net	96,944	23,611	21,473				142,028
Accrued unbilled revenues, net	64,906	13,332	12,535				90,773
Other accounts receivable, net	17,614	4,326	2,184			(5,586)	18,538
Fuel oil stock, at average cost	95,688	16,274	16,458				128,420
Materials & supplies, at average cost	19,480	4,536	12,764				36,780
Prepayments and other	9,454	3,835	2,711				16,000
Total current assets	323,492	70,031	79,033	92	10	(29,436)	443,222
Other long-term assets							
Regulatory assets	312,723	57,857	54,034				424,614
Unamortized debt expense	9,789	2,834	2,218				14,841
Other	38,096	7,992	15,867				61,955
Total other long-term assets	360,608	68,683	72,119				501,410
	$ 3,083,807	764,566	637,293	92	10	(491,700)	$ 3,994,068
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,315,324	240,957	221,210	90	7	(462,264)	$ 1,315,324
Cumulative preferred stock not subject to mandatory redemption	22,293	7,000	5,000				34,293
Long-term debt, net	672,235	211,263	174,381				1,057,879
Total capitalization	2,009,852	459,220	400,591	90	7	(462,264)	2,407,496
Current liabilities							
Short-term borrowings-nonaffiliates	14,100						14,100
Short-term borrowings-affiliate	9,000	14,850				(23,850)	
Accounts payable	104,279	21,313	12,947				138,539
Interest and preferred dividends payable	14,256	4,501	2,918			(6)	21,669
Taxes accrued	79,393	26,286	19,061				124,740
Other	30,030	10,317	14,496	2	3	(5,580)	49,268
Total current liabilities	251,058	77,267	49,422	2	3	(29,436)	348,316

Deferred credits and other liabilities							
Deferred income taxes	137,476	25,790	12,953				176,219
Regulatory liabilities	200,021	54,416	38,862				293,299
Unamortized tax credits	32,737	13,060	12,219				58,016
Retirement benefits liability	219,682	34,859	39,179				293,720
Other	49,011	30,104	11,837				90,952
Total deferred credits and other liabilities	638,927	158,229	115,050				912,206
Contributions in aid of construction	183,970	69,850	72,230				326,050
	$ 3,083,807	764,566	637,293	92	10	(491,700)	$ 3,994,068

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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)

Six months ended June 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		35,694	6,578	2,155	(4)	(10)	(8,719)		35,694
Retirement benefit plans:									
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes		1,813	385	320			(705)		1,813
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits		(1,697)	(376)	(308)			684		(1,697)
Comprehensive income (loss)		35,810	6,587	2,167	(4)	(10)	(8,740)		35,810
Common stock dividends		(26,887)	(6,203)	(2,276)			8,479		(26,887)
Common stock issue expenses		(7)	(3)				3		(7)
Balance, June 30, 2010	$	1,315,324	240,957	221,210	90	7	(462,264)	$	1,315,324

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Common Stock Equity (unaudited)

Six months ended June 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		29,627	5,105	4,125	(8)	(13)	(9,209)		29,627
Retirement benefit plans:									
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes		5,350	813	654			(1,467)		5,350
Less: reclassification adjustment for impact of D&Os		(5,233)	(804)	(641)			1,445		(5,233)

of the PUC included in regulatory assets, net of tax benefits									
Comprehensive income (loss)		29,744	5,114	4,138	(8)	(13)	(9,231)		29,744
Capital stock expense		(4)	(1)	(1)			2		(4)
Common stock dividends		(21,135)		(3,639)			3,639		(21,135)
Issuance of common stock						25	(25)		
Balance, June 30, 2009	$	1,197,447	226,518	215,880	97	153	(442,648)	$	1,197,447

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Six months ended June 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)	$ 36,234	6,845	2,346	(4)	(10)	(8,719)	$ 36,692
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(8,769)					8,719	(50)
Common stock dividends received from subsidiaries	8,529					(8,479)	50
Depreciation of property, plant and equipment	43,825	18,253	15,213				77,291
Other amortization	2,411	1,716	(1,026)				3,101
Deferred income taxes	(3,745)	(199)	(578)				(4,522)
Tax credits, net	1,609	238	(162)				1,685
Allowance for equity funds used during construction	(3,158)	(201)	(261)				(3,620)
Decrease in cash overdraft			(302)				(302)
Changes in assets and liabilities:							
Increase in accounts receivable	(18,653)	(1,141)	(2,921)			4,457	(18,258)
Decrease (increase) in accrued unbilled revenues	(6,884)	316	71				(6,497)
Increase in fuel oil stock	(45,841)	(3,634)	(284)				(49,759)
Decrease (increase) in materials and supplies	(1,102)	(530)	760				(872)
Increase in regulatory assets	(1,331)	(695)	(226)				(2,252)
Increase in accounts payable	1,206	3,944	678				5,828
Changes in prepaid and accrued income and utility revenue taxes	(21,463)	(4,904)	(5,497)				(31,864)
Changes in other assets and liabilities	12,356	2,891	3,880	(2)	1	(4,457)	14,669
Net cash provided by (used in) operating activities	(4,776)	22,899	11,691	(6)	(9)	(8,479)	21,320
Cash flows from investing activities:							
Capital expenditures	(56,495)	(10,996)	(11,020)				(78,511)
Contributions in aid of construction	5,871	2,206	1,353				9,430
Advances from (to) affiliates	5,250		2,000			(7,250)	
Net cash used in investing activities	(45,374)	(8,790)	(7,667)			(7,250)	(69,081)
Cash flows from financing activities:							
Common stock dividends	(26,887)	(6,203)	(2,276)			8,479	(26,887)
Preferred stock dividends of HECO and subsidiaries	(540)	(267)	(191)				(998)
Net increase (decrease) in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	12,100	(5,250)				7,250	14,100

Other	(948)	(278)	(123)				(1,349)
Net cash used in financing activities	(16,275)	(11,998)	(2,590)			15,729	(15,134)
Net increase (decrease) in cash and cash equivalents	(66,425)	2,111	1,434	(6)	(9)		(62,895)
Cash and cash equivalents, beginning of period	70,981	2,006	474	98	19		73,578
Cash and cash equivalents, end of period	$ 4,556	4,117	1,908	92	10		$ 10,683

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Six months ended June 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Cash flows from operating activities							
Net income (loss)	$ 30,167	5,372	4,316	(8)	(13)	(9,209)	$ 30,625
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(9,259)					9,209	(50)
Common stock dividends received from subsidiaries	3,689					(3,639)	50
Depreciation of property, plant and equipment	41,595	16,501	14,753				72,849
Other amortization	1,528	1,696	2,278				5,502
Changes in deferred income taxes	5,000	2,754	(490)				7,264
Changes in tax credits, net	(724)	(303)	(294)				(1,321)
Allowance for equity funds used during construction	(5,878)	(1,509)	(338)				(7,725)
Changes in assets and liabilities:							
Decrease in accounts receivable	37,514	9,050	8,089			3,729	58,382
Decrease in accrued unbilled revenues	20,347	4,899	2,793				28,039
Decrease in fuel oil stock	16,643	2,846	2,894				22,383
Decrease (increase) in materials and supplies	(1,066)	(213)	739				(540)
Increase in regulatory assets	(6,787)	(1,420)	(2,357)				(10,564)
Increase (decrease) in accounts payable	(4,048)	(10,352)	1,519				(12,881)
Changes in prepaid and accrued income and utility revenue taxes	(42,552)	(9,376)	(9,331)				(61,259)
Changes in other assets and liabilities	6,387	(3,980)	(2,203)	(14)	(3)	(3,729)	(3,542)
Net cash provided by (used in) operating activities	92,556	15,965	22,368	(22)	(16)	(3,639)	127,212
Cash flows from investing activities							
Capital expenditures	(122,500)	(39,002)	(12,971)				(174,473)
Contributions in aid of construction	2,851	1,382	684				4,917
Advances from (to) affiliates	(17,250)		(7,000)			24,250	
Investment in consolidated subsidiary	(25)					25	
Net cash used in investing activities	(136,924)	(37,620)	(19,287)			24,275	(169,556)
Cash flows from financing activities							
Common stock dividends	(21,135)		(3,639)			3,639	(21,135)

Preferred stock dividends of HECO and subsidiaries	(540)	(267)	(191)				(998)
Proceeds from issuance of long-term debt		3,168					3,168
Proceeds from issuance of common stock					25	(25)	
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	66,054	17,250				(24,250)	59,054
Increase (decrease) in cash overdraft	(1,046)		84				(962)
Other	(6)	(1)	(1)				(8)
Net cash provided by (used in) financing activities	43,327	20,150	(3,747)		25	(20,636)	39,119
Net increase (decrease) in cash and cash equivalents	(1,041)	(1,505)	(666)	(22)	9		(3,225)
Cash and cash equivalents, beginning of period	2,264	3,148	1,349	123	17		6,901
Cash and cash equivalents, end of period	$ 1,223	1,643	683	101	26		$ 3,676

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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 annual (as of and for the year ended December 31, 2009) and the quarterly (as of and for the three months ended March 31, 2010 and as of and for the three and six months ended June 30, 2010) consolidated financial statements of HEI and HECO and accompanying notes included in the Forms 10-Q for the first and second quarters of 2010.

HEI Consolidated

RESULTS OF OPERATIONS

(in thousands, except per share amounts)	Three months ended June 30 2010	2009	% change	Primary reason(s) for significant change*
Revenues	$ 655,664	$ 525,901	25	Increase for the electric utility segment, partly offset by a decrease for the bank segment
Operating income	63,631	35,055	82	Increase for the electric utility and the bank segments
Net income for common stock	29,262	15,479	89	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	$ 0.31	$ 0.17	82	Higher net income, partly offset by higher weighted average shares outstanding
Weighted-average number of common shares outstanding	93,159	91,384	2	Issuances of shares under the HEI Dividend Reinvestment and Stock Purchase Plan and Company employee plans

(in thousands, except per share amounts)	Six months ended June 30 2010	2009	% change	Primary reason(s) for significant change*
Revenues	$ 1,274,704	$ 1,069,698	19	Increase for the electric utility segment, partly offset by a decrease for the bank segment
Operating income	124,338	79,713	56	Increase for the electric utility and the bank segments
Net income for common stock	56,388	35,874	57	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	$ 0.61	$ 0.39	56	Higher net income, partly offset by higher weighted average shares outstanding

Weighted-average number of common shares outstanding	92,867	90,996	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 second quarters of 2010 and 2009 were 35% and 31%, respectively. The Company s effective tax rates (federal and state) for the first six months of 2010 and 2009 were 35% and 33%, respectively.

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Dividends. The payout ratios for 2009 and the first six months of 2010 were 137% and 102%, 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 Financial Forecasts; Hawaii Tourism Authority (HTA); Honolulu Board of REALTORS®; and national and local newspapers).

Nationally, the signs of economic recovery continue although economists expect the recovery will remain slow. The U.S. economy has grown for four quarters in a row, with the advance estimate of second quarter 2010 gross domestic product (GDP) growing at a seasonally adjusted rate of 2.4%. This is a decline from the revised first quarter growth of 3.7%. The July 2010 Blue Chip consensus estimate is for growth of 2.7% and 2.8% in the third and fourth quarters respectively. Although the consensus forecast is for growth in the remainder of the year, the estimates have declined from the April 2010 Blue Chip consensus as there are indications that growth will moderate. There is talk of a potential double-dip recession, but according to the Blue Chip consensus, the odds of a quarter of contraction in real GDP before the end of 2011 are one in five.

Japan s economy, while continuing to grow, is also exhibiting signs that the growth is slowing. In June 2010, Japan s unemployment rate rose to 5.3%, a seven month high. Also, household spending increased by 0.5% in June 2010 from June 2009 following a decline of 0.7% in May 2010 from May 2009.

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 seeing signs of recovery in 2010 and beyond, but the outlook remains for the recovery to be slow and gradual.

The outlook for two of Hawaii s major industries, visitors and construction, is mixed. Visitor arrival numbers in 2010, continue to show the positive growth that began at the end of 2009. However, construction jobs losses and declining permit values have continued in the first five months of 2010, although at a slower pace than the significant declines of 2009. These industries are key to Hawaii s economic recovery.

Visitor arrivals were up 5.7% through the first half of 2010 as compared to the same period in 2009. UHERO projects 2010 arrivals will be up 4.0% from 2009 levels following decreases of 4.4% and 10.5% in 2009 and 2008 respectively. Visitor expenditures were up 7.8% for the first half of 2010 compared to same period in 2009. DBEDT projects 2010 visitor expenditures will be 4.9% higher than 2009 following double digit percent decreases in 2009 and 2008.

The impact of the recession on Hawaii s construction industry continues. For the first five months of 2010, the value of total private building permits in Hawaii declined by 13.3% from the same period in 2009. Permit values for new residential construction and additions and alterations declined, but commercial and industrial permit values increased during this period. Construction jobs were also down 8.9% during this period.

UHERO projects that private construction is nearing the bottom and should start to see some benefit from Federal and State spending programs.

Conditions in the housing market appear to be moving towards a recovery. The Oahu housing market in the first half of 2010 has seen increased closed sales and median sales prices as well as a decrease in days on the market compared to the same period in 2009. On Maui, Kauai and the Big Island, first half 2010 sales are up over 2009, while median prices are down. 30-year mortgage rates are at an all time low and the inventory of homes available on Oahu is at the lowest point since before the recession began, both of which are positive indicators of continued strength in the housing market.

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 was 6.3% in June 2010, down from the high of 7.0% reached in 2009 and the lowest rate since February 2009. Hawaii s unemployment rate remains below the U.S. average of 9.5% and is expected to average 6.8% in 2010. Unemployment on the Neighbor Islands will continue to be much higher than on Oahu. Total jobs declined by 4.4% in 2009 and were down 1.4% in the first five months of 2010 compared to the same period last year. The slow rate of recovery means it will take many years to replace

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the jobs that have been lost over the past two years. DBEDT projects total wage and salary jobs will decline by 0.9% in 2010, followed by a 0.8% increase in 2011. In addition to job losses, furloughs for county employees in all four counties were implemented for the fiscal year beginning July 1, 2010 while state employee furloughs continue.

Real personal income (which includes unemployment compensation) in Hawaii is expected to be 0.4% lower in 2010 according to UHERO s estimate and slightly higher, by 0.2%, as projected by DBEDT. This is on top of a 0.1% decline in 2009.

The price of a barrel of crude oil has declined recently in light of U.S. and global economic uncertainty (closing at $76.62 per barrel on July 15, 2010 compared to $86.15 on April 30, 2010), although prices remain much higher than the low of $34.03 per barrel on February 12, 2009.

Interest rates remained low during the first six months of 2010 and are expected to remain low for the remainder of the year. The low level of interest rates continued to put downward pressure on yields on loans and investments, but also contributed to lower deposit and borrowing costs.

The Hawaii economy is showing signs of recovery, which will continue to depend significantly on the U.S. and international economies, particularly Japan. Assuming the U.S. and international conditions continue to improve, Hawaii s economy is expected to experience a gradual recovery in 2010 continuing through to 2013.

Retirement benefits. For the first six months of 2010, the Company s and HECO and its subsidiaries defined benefit retirement plans assets generated a loss, including investment management fees, of 1.6%. The market value of the defined benefit retirement plans assets of the Company as of June 30, 2010 was $846 million compared to $874 million at December 31, 2009, a decrease of approximately $28 million. The market value of the defined benefit retirement plans assets of HECO and its subsidiaries as of June 30, 2010 was $767 million compared to $792 million at December 31, 2009, a decrease of approximately $25 million.

The Company and HECO and its subsidiaries estimate that the cash funding for the 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.

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.

Other segment.

(in thousands)	Three months ended June 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ (63)	$ (15)	NM	
Operating loss	(3,579)	(2,614)	NM	Higher compensation, proxy and financing costs, partly offset by lower retirement benefit expenses
Net loss	(4,511)	(4,037)	NM	See explanation for operating loss

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(in thousands)		Six months ended June 30 2010		2009	% change	Primary reason(s) for significant change
Revenues	$	(48)	$	(47)	NM	
Operating loss		(7,252)		(6,146)	NM	Higher compensation and financing costs, partly offset by lower retirement benefit expenses
Net loss		(9,173)		(8,656)	NM	See explanation for operating loss

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 primarily providing windfarm operational and maintenance services to an affiliated electric utility that will cease such services when the windfarm is dismantled in 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)		June 30, 2010			December 31, 2009	
Short-term borrowings other than bank	$	55	2%	$	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		1,467	50		1,442	50
	$	2,921	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 June 30, 2010. HEI periodically utilizes long-term debt, historically its 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.

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 (2010 Facility). This 2010 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.

Any draws on the 2010 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. 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

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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 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 (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HEI). In addition to customary defaults, HEI s failure to maintain its financial ratio, as defined in its agreement, or meet other requirements 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 June 30, 2010, as calculated under the agreement) and Consolidated Net Worth of at least $975 million (Net Worth of $1.5 billion as of June 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)	Six months ended June 30, 2010 Average balance	Balance June 30, 2010	Balance December 31, 2009
Short-term borrowings(1)			
HEI commercial paper	$ 41	$ 41	$ 42
HEI line of credit draws			
	$ 41	$ 41	$ 42
Line of credit facility (expiring May 7, 2013)(1)		$ 125	$ 100
Undrawn capacity under HEI s line of credit facility (2)		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.
(2) At July 30, 2010, HEI s credit facility expiring May 7, 2013 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 August 2, 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.

HEI s overall S&P corporate credit rating is BBB/Negative/A-3. HEI s issuer rating by Moody s is Baa2 and Moody s outlook for HEI is stable.

The rating agencies use a combination of qualitative measures (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HEI securities. In 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

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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 $21 million through the issuance of approximately 0.9 million shares under these plans during the first six months of 2010. HEI also makes registered public offerings of its common stock from time to time.

For the first six months of 2010, net cash provided by operating activities of consolidated HEI was $85 million. Net cash used by investing activities for the same period was $187 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 $124 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 first six months of 2010, HECO and ASB paid dividends to HEI of $27 million and $13 million, respectively.

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

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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, 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).

The Company was not required to make any contributions to the qualified pension plans for 2009 to meet minimum funding requirements pursuant to ERISA, including changes promulgated by the Pension Protection Act of 2006, but the Company made voluntary contributions in 2009. Contributions to the retirement benefit plans totaled $25 million in 2009 (comprised of $24 million made by the utilities, $1 million by HEI and nil by ASB) and are expected to total $32 million in 2010 ($31 million by the utilities, $1 million by HEI and nil by ASB). In addition, the Company paid directly $1 million of benefits in 2009 and expects to pay $2 million of benefits in 2010. Depending on the performance of the assets held in the plans trusts and numerous other factors, additional contributions may be required in the future to meet the minimum funding requirements of ERISA or to pay benefits to plan participants. The Company believes it will have adequate access to capital resources to support any necessary funding requirements.

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 June 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 584,095	$ 450,417	30	Higher fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers ($127 million) and HECO test year 2009 interim rate increase ($18 million), partially offset by lower KWH sales ($5 million) and lower DSM costs recovered through a surcharge ($10 million)
Expenses				
Fuel oil	215,322	131,885	63	Higher fuel oil costs partly offset by increased fuel efficiency and less KWHs generated
Purchased power	139,513	115,189	21	Higher fuel costs
Other operation	60,254	63,181	(5)	See Results three months ended June 30, 2010 below
Maintenance	32,223	29,431	9	See Results three months ended June 30, 2010 below
Depreciation	38,649	36,425	6	Additions to plant in service in 2009
Taxes, other than income taxes	54,170	41,975	29	Increase in revenues
Other	2,529	168	1,405	Write-down of investment in combined heat and power system (see Most recent rate requests below)
Operating income	41,435	32,163	29	HECO test year 2009 interim rate increase, partly offset by higher expenses
Net income for common stock	17,642	15,495	14	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)	2,374	2,400	(1)	
Cooling degree days (Oahu)	1,210	1,244	(3)	
Average fuel oil cost per barrel	$ 86.38	$ 50.69	70	

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(dollars in thousands, except per barrel amounts)	Six months ended June 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 1,132,206	$ 912,214	24	Higher fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers ($198 million), HECO test year 2009 interim rate increase ($33 million), and higher KWH sales ($6 million), partially offset by lower DSM costs recovered through a surcharge ($18 million)
Expenses				
Fuel oil	427,074	277,174	54	Higher fuel oil costs and more KWHs generated, partly offset by increased fuel efficiency
Purchased power	256,295	229,673	12	Higher fuel costs, partly offset by less KWHs purchased
Other operation	119,498	125,578	(5)	See Results six months ended June 30, 2010 below
Maintenance	59,276	55,594	7	See Results six months ended June 30, 2010 below
Depreciation	77,291	72,849	6	Additions to plant in service in 2009
Taxes, other than income taxes	105,961	87,710	21	Increase in revenues
Other	2,767	404	585	Write-down of investment in combined heat and power system (see Most recent rate requests below)
Operating income	84,044	63,232	33	Higher sales and HECO test year 2009 interim rate increase, partly offset by higher expenses
Net income for common stock	35,694	29,627	20	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)	4,647	4,631		
Cooling degree days (Oahu)	2,067	2,003	3	
Average fuel oil cost per barrel	$ 84.13	$ 55.19	52	

Note: The electric utilities had an effective tax rate for the second quarters of 2010 and 2009 of 36% and 35%, respectively. The electric utilities had an effective tax rate for the first six months of 2010 and 2009 of 37% and 36%, respectively.

See Economic conditions in the HEI Consolidated section above.

Results three months ended June 30, 2010.Operating income for the second quarter of 2010 increased 29% from the same period in 2009 due primarily to the HECO test year 2009 interim rate increase ($18 million, including $3 million related to additional rate relief implemented on February 20, 2010 related to CIP CT-1) and improved fuel efficiency, primarily due to ST-7.

Other operation expenses decreased by $2.9 million in the second quarter of 2010 compared to the same period in 2009 primarily due to $9.4 million lower DSM expenses (see Demand-side management programs below) that are generally passed on to customers through surcharges, partly offset by $4.2 million higher employee benefit costs and $1.7 million higher production operating expenses, including expenses related to environmental compliance and CIP CT-1. Maintenance expense increased $2.8 million primarily due to higher production maintenance.

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Results six months ended June 30, 2010.Operating income for the first six months of 2010 increased 33% from the same period in 2009 due primarily to the HECO test year 2009 interim rate increase ($33 million), improved fuel efficiency, primarily due to ST-7, and lower other operation expenses, partly offset by higher maintenance expenses. For the year 2010, management expects KWH sales to continue to be generally flat compared to 2009.

Other operation expenses decreased by $6.1 million in the first six months of 2010 compared to the same period in 2009 primarily due to lower DSM expenses (see Demand-side management programs below) that are generally passed on to customers through surcharges ($17 million), partially offset by $9.9 million higher administrative and general expenses including $7.9 million higher employee benefit costs. Maintenance expense increased $3.7 million primarily due to the greater scope and number of generating unit overhauls.

O&M expenses for the year 2010 are expected to be 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 and such increased costs are likely to continue.

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, and additional ones have been committed to in the Energy Agreement.

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 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 and its testing of the unit has confirmed that biodiesel is a viable fuel for the unit. HECO is 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 July 2009, HECO and MECO submitted separate applications with the PUC to approve biodiesel supply contracts for their respective biodiesel demonstration projects, and to include the biodiesel fuel costs and related costs in their respective ECAC. In June 2010, the PUC approved HECO and MECO s biodiesel fuel supply contracts, 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, in connection with proposed demonstration projects to test the use of biofuels. 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

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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 an all-fuels RFP in the fourth quarter of 2010 to solicit proposals for fuel, including fuel for CIP CT-1 that is not supplied through a contract for local fuels upon 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. The utilities are evaluating potential modifications to the program application, including the possibility of deferring implementation of the program at HELCO and MECO until further grid integration studies are completed.

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. An Award Group of bidders was selected in October 2009. 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 December 11, 2009, the PUC issued a D&O that allows HECO to defer costs for the Big Wind Implementation Studies for later review for prudence and reasonableness. See Hawaii Clean Energy Initiative HCEI projects in Note 5 of HECO s Notes to Consolidated Financial Statements.

In July 2010, the utilities requested PUC approval of a three-year Electric Vehicle (EV) Charging Rate Pilot Project, which would offer lower electric rates during off-peak hours, effective October 1, 2010. The project is to encourage the use of EVs in Hawaii as highway-capable EVs become commercially available in the next year.

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.

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

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utility retains its traditional obligation to offer to purchase capacity and energy from a Qualifying Facility (QF) at avoided cost upon reasonable terms and conditions approved by the PUC.

The utilities have requested and received approval for waivers from the competitive framework to negotiate modifications to existing PPAs that generate electricity from renewable resources. They also are negotiating or have negotiated agreements with renewable energy projects that were grandfathered from the competitive bidding process, including Kahuku Wind Power, Honua Power and Sea Solar Power International. See Renewable energy strategy above for a discussion of certain current and potential PPAs with non-utility generators using renewable sources.

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

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.

The January 2006 D&O also required the utilities to file tariffs and establish standby rates based on unbundled costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services). See DG tariff proceeding below.

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 February 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.

DG tariff proceeding. In December 2006, the PUC opened a proceeding to investigate the utilities proposed DG interconnection tariff modifications and standby rate tariffs. In April and May 2008, the PUC approved interconnection tariffs and a settlement agreement on the standby service tariff, respectively.

In the fourth quarter of 2008, the PUC approved revised interconnection tariff sheets and closed the DG tariff proceeding.

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

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facility. The remaining issues continue to be evaluated in the proceeding. Final statements of position are due in November 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 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%, 11.5% and 10.7% were found to be reasonable by the PUC in the most recent final rate decisions issued in May 2008, February 2001 and July 2010 in HECO, HELCO and MECO rate cases based on 2005, 2000 and 2007 test years, respectively. The ROACEs used by the PUC for purposes of the most recent interim rate increases issued in August 2009, April 2007 and July 2010 in HECO, HELCO and MECO rate cases based on 2009, 2006 and 2010 test years were 10.5%, 10.7% and 10.5%, respectively.

For the 12 months ended June 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 7.86%, 7.42% and 3.88%, respectively. The utilities actual

ROACEs were lower than their 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 8.66% for HECO, 9.14% for HELCO and 8.67% for MECO (final D&Os noted above). The RORs used by the PUC for purposes of the most recent interim increases were 8.45% for HECO, 8.33% for HELCO and 8.43% for MECO (interim D&Os noted above). For the 12 months ended June 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 6.98%, 6.52% and 4.81%, 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 MECO s 2007 test year rate case final D&O, the PUC approved MECO s pension and OPEB tracking mechanisms. For a description of the utilities pension and OPEB tracking mechanisms, see Balance

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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 2007 and 2009 and HELCO s 2006 test year rate cases and the interim increases granted in those rate cases, 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.

For a description of the status of rate-making changes that the parties have agreed to pursue under the Energy Agreement, see below and Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements.

HECO.

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 methodology as proposed by HECO in its separate depreciation proceeding. See Note 11 of HECO s Notes to Consolidated Financial Statements.

HELCO.

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.

On July 29, 2010, the Consumer Advocate filed its direct testimony, which recommended a revenue increase of $2.3 million, based on a ROACE of 9.5% and a ROR of 8.03% on a $471 million rate base. The difference between HELCO s and the Consumer Advocates proposed increases is due to the Consumer Advocate s lower recommended ROACE and ROR, and other proposed adjustments in test year expenses.

Evidentiary hearings are scheduled for October 2010. Management cannot predict the timing, or the ultimate outcome, of an interim or final D&O in this rate case.

MECO.

2007 test year rate case. In February 2007, MECO filed a request for a general rate increase of $19.0 million, based on a 2007 test year. In September 2007, MECO proposed an updated lower increase in annual revenues of $18.3 million, or 5.1% over the electric rates then in effect, based on an 11.25% ROACE and 8.98% ROR on a $386 million rate base. MECO s request included a proposed new tiered rate structure to reward residential customers who practice energy conservation with lower electric rates for lower monthly usage. The proposed rate increase would pay for improvements to increase reliability, including two new generating units, and transmission and distribution infrastructure improvements.

In December 2007, MECO and the Consumer Advocate reached a settlement of all the revenue requirement issues in this rate case, and the PUC issued an interim D&O based on the settlement agreement granting MECO an increase of $13.2 million in annual revenues, or 3.7%, based on a 10.7% ROACE and an 8.67% ROR on a $383 million rate base.

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On July 30, 2010, the PUC issued a final D&O in the rate case confirming the December 2007 interim D&O rate increase.

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.

MECO s filing proposes an inclining rate block structure for residential customers (similar to the structure MECO proposed in its 2007 test year rate case) and an optional residential and commercial time-of-use service rate to enable customers to manage their energy usage.

On May 5, 2010, the Consumer Advocate filed its direct testimony which recommended a revenue increase of $7.0 million, based on a 9.50% ROACE and a 7.86% ROR on a $384 million rate base.

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 temporary approval of new depreciation rates and methodology proposed by MECO in its separate depreciation proceeding.

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 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.

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

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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 (2007, 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&O for the MECO 2007 test year rate case, the PUC found MECO s ECAC to comply with Act 162 and that it should be implemented as agreed by the parties in the rate case proceeding. In their settlement letter, the parties had agreed that no further changes are required to MECO s ECAC in order to comply with the requirements of Act 162.

Revisions to depreciation rates. HELCO and MECO s 2010 test year and HECO s 2011 test year general rate increase applications are based on proposed revised depreciation rates for which PUC approval was requested in applications filed in November 2009 (HELCO), September 2009 (MECO), and March 2010 (HECO). If a decision on their depreciation rates change has not been rendered by the time an interim D&O is to be issued in their proceedings, the applications request that the interim rate relief be based on their existing depreciation rates, and that upon issuance of the D&O on their proposed depreciation rates change, the PUC approve an adjustment (i.e., depreciation step down) that would effectively implement the difference between the revenue increase based on their existing depreciation rates and their new lower depreciation rates approved. In July 2010, the PUC approved MECO and the Consumer Advocate s joint proposal for temporary approval of MECO s proposed depreciation rates effective from the effective date of the interim rates approved by the PUC in MECO s 2010 rate case.

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.

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

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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 April 2008, HECO filed an application for approval of a Dynamic Pricing Pilot (DPP) Program and for recovery of the incremental costs of the program through the DSM Adjustment component of the IRP Cost Recovery Provision. Dynamic pricing is a type of demand response 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. The proposed pilot program would run for approximately one year and test the effect of a demand response program on a sample of residential customers. In June 2009, the PUC, in its Order Directing HECO to Modify its Dynamic Pricing Pilot Program, directed HECO to modify the DPP Program to address the concerns and recommendations (e.g., increasing sample size and testing price sensitivity) of the Consumer Advocate, or alternatively, HECO and the Consumer Advocate may file a stipulated proposed DPP Program.

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 proposed IRPs have been planning strategies, rather than fixed courses of action, and the resources ultimately added to their systems may differ from those included in their 20-year plans. Under the PUC s IRP framework, the utilities were required to submit annual evaluations of their plans (including a revised five-year program implementation schedule) and to submit new plans on a three-year cycle, subject to changes approved by the PUC. Prior to implementing DSM programs, separate PUC approval proceedings must be completed.

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 (since February 2001), HECO (since September 2005) and MECO (since December 2007) now recover IRP costs (which are included in O&M) through base rates. Previously, HECO, HELCO and MECO recovered these costs through a surcharge. Also, see Note 5 in HECO s Notes to Consolidated Financial Statements and 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. Requests by the parties to the Energy Agreement to move to the CESP process were filed with the PUC on November 6, 2008, and the PUC acted on those requests by ordering the utilities and the Consumer Advocate to develop a joint proposal for a framework for the CESP process. HECO and the Consumer Advocate filed a proposed CESP framework with the PUC on April 28, 2009. The proposed CESP framework revises the previous IRP framework and proposes a planning process to develop

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generation and transmission resource plan options for multiple 20-year planning scenarios. From these scenarios, the framework proposes the development of a 5-year Action Plan based on a range of resource needs identified through the various scenarios analyzed. Furthermore, the framework proposes that the CESP include the identification of Renewable Energy Zones, or geographic areas of the islands of rich renewable energy resources in which infrastructure improvements should be focused. The framework also proposes that the CESP include the identification of any geographic areas of the distribution system in which DG or DSM resources are of higher value. The parties committed to supporting reasonable and prudent investment in the ongoing maintenance and upgrade of the existing generation, transmission and distribution systems, unless the CESP process determines otherwise. In May 2009, the PUC opened an investigative proceeding to examine the proposed CESP framework. The PUC held hearings in February 2010 and briefs are scheduled to be filed in the third quarter of 2010.

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. In the fourth quarter of 2008, however, 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.

Adequacy of supply.

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 issued an order initiating 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 138 kilovolts (kV) transmission system, one of which resulted in a short-circuit over all three phases of the Kahe-Waiau 138 kV line, setting in motion a series of events that resulted in the necessary loss of customer load, loss of generation and the eventual island-wide shut down of HECO s 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 the restoration of power as quickly as possible under the circumstances, while also ensuring the safety and protection of HECO s employees and customers and preventing any further or permanent damage to the electric system from attempts to bring the system back too quickly. POWER made a

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number of recommendations, largely technical in nature, for HECO to consider that may reduce the likelihood of the recurrence of a similar power outage or minimize the duration of an outage should one occur in the future.

In January 2010, the Consumer Advocate submitted its Statement of Position that HECO could not have anticipated or prevented the outage through reasonable measures, given the design and configuration of the equipment and systems in place at the time, and that HECO 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.

In April 2010, HECO filed its Final Statement of Position in the docket reiterating its belief that the activities and performance of HECO prior to and during the outage were reasonable, prudent and in the public interest.

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.

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 April 29, 2010, the state House and Senate voted to override the Governor s veto of a bill that increases the tax on petroleum products shipped to Hawaii from $0.05 to $1.05 per barrel. The bill, which now becomes law, is expected to generate funds to help reduce the state s budget deficit and finance food and renewable energy programs. The higher tax, which is expected to be passed on to consumers, will increase the price of gasoline and electricity.

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. Pursuant to the contract with Sensus, either party may terminate the contract if the PUC does not approve the application.

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 a request to defer certain costs of extended pilot testing and an update on developments in the Smart Grid, CIS and cyber-security areas and a proposal to suspend the remaining procedural steps scheduled in the docket pending HECO s report of the results of the extended pilot test.

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 June 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.

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.

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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)	June 30, 2010		December 31, 2009	
Short-term borrowings	$ 14	1%	$	%
Long-term debt, net	1,058	44	1,058	44
Preferred stock	34	1	34	1
Common stock equity	1,315	54	1,306	55
	$ 2,421	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 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 (HECO Facility). 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 (and such approval was requested in July 2010). The HECO 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 HECO s subsidiaries and for HECO s capital expenditures, working capital and general corporate purposes.

Any draws on the HECO 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. 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 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 (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

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Capitalization Ratio to exceed 65% (ratio of 48% for HELCO and 44% for MECO as of June 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 54% as of June 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:

(in millions)	Six months ended June 30, 2010 Average balance	Balance June 30, 2010	Balance December 31, 2009
Short-term borrowings(1)			
Commercial paper	$ 5	$ 14	$
Line of credit draws			
Borrowings from HEI			
Line of credit facilities			
Undrawn capacity under line of credit facility expiring May 6, 2011(2)	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) HECO had no borrowings from HEI as of December 31, 2009 or during the six months ended June 30, 2010.

(2) At July 30, 2010, HECO s credit facility expiring on May 6, 2011 was undrawn.

At June 30, 2010, HECO had $9 million of short-term borrowings from MECO and HELCO had $15 million of short-term borrowings from HECO.

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 to sell special purpose revenue bonds for the benefit of the utilities in the future.

As of August 2, 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

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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.

HECO s overall S&P corporate credit rating is BBB/Negative/A-3. HECO s issuer rating by Moody s is Baa1 and Moody s outlook for HECO is stable.

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:

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.

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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 used $21 million in net cash during the first six months of 2010. Investing activities during the same period used net cash of $69 million for capital expenditures, net of contributions in aid of construction. Financing activities for the same period used net cash of $15 million, primarily due the payment of $28 million of common and preferred dividends, partly offset by a $14 million net increase in short-term borrowings.

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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Bank

RESULTS OF OPERATIONS

(in thousands)	Three months ended June 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 71,632	$ 75,499	(5)	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 half 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
Operating income	25,775	5,506	368	Lower provision for loan losses, higher noninterest income and lower noninterest expenses, partially offset by lower net interest income
Net income	16,131	4,021	301	Higher operating income

(in thousands)	Six months ended June 30 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 142,546	$ 157,531	(10)	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 half 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
Operating income	47,546	22,627	110	Lower provision for loan losses, higher noninterest income and lower noninterest expenses, partially offset by lower net interest income
Net income	29,867	14,903	100	Higher operating income

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 six months ended June 30, 2010 and 2009.

	Three months ended June 30					
	2010			2009		
($ in thousands)	**Average Balance**	**Interest**	**Average Rate (%)**	**Average Balance**	**Interest**	**Average Rate (%)**
Assets:						
Other investments (1)	$ 313,319	$ 137	0.17	$ 228,623	$ 55	0.09
Investment and mortgage-related securities	574,932	3,509	2.44	643,152	7,088	4.41
Loans receivable (2)	3,641,540	49,328	5.42	3,979,321	55,363	5.57
Total interest-earning assets	4,529,791	52,974	4.68	4,851,096	62,506	5.16
Allowance for loan losses	(41,485)			(43,617)		
Non-interest-earning assets	407,839			330,398		
Total assets	$ 4,896,145			$ 5,137,877		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,412,104	916	0.15	$ 2,200,413	1,798	0.33
Time certificates	791,248	2,936	1.49	1,236,328	8,104	2.63
Total interest-bearing deposits	3,203,352	3,852	0.48	3,436,741	9,902	1.16
Other borrowings	273,526	1,418	2.05	404,521	2,241	2.20
Total interest-bearing liabilities	3,476,878	5,270	0.61	3,841,262	12,143	1.27
Non-interest bearing liabilities:						
Deposits	818,568			737,219		
Other	96,523			88,192		
Stockholder s equity	504,176			471,204		
Total Liabilities and Stockholder s Equity	$ 4,896,145			$ 5,137,877		
Net interest income		$ 47,704			$ 50,363	
Net interest margin (%) (3)			4.22			4.16

	Six months ended June 30					
	2010			2009		
($ in thousands)	**Average Balance**	**Interest**	**Average Rate (%)**	**Average Balance**	**Interest**	**Average Rate (%)**
Assets:						
Other investments (1)	$ 353,730	$ 320	0.18	$ 168,206	$ 55	0.06
Investment and mortgage-related securities	515,277	6,643	2.58	659,449	14,764	4.48
Loans receivable (2)	3,660,355	99,073	5.43	4,077,634	113,455	5.58
Total interest-earning assets	4,529,362	106,036	4.69	4,905,289	128,274	5.24
Allowance for loan losses	(41,178)			(39,961)		
Non-interest-earning assets	410,398			344,741		
Total assets	$ 4,898,582			$ 5,210,069		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,390,957	1,956	0.17	$ 2,160,417	4,145	0.39
Time certificates	819,729	6,319	1.55	1,281,392	17,322	2.73

Total interest-bearing deposits	3,210,686	8,275	0.52	3,441,809	21,467	1.26
Other borrowings	284,138	2,844	1.99	482,411	5,505	2.27
Total interest-bearing liabilities	3,494,824	11,119	0.64	3,924,220	26,972	1.38
Non-interest bearing liabilities:						
Deposits	807,696			725,922		
Other	94,694			86,783		
Stockholder s equity	501,368			473,144		
Total Liabilities and Stockholder s Equity	$ 4,898,582			$ 5,210,069		
Net interest income		$ 94,917			$ 101,302	
Net interest margin (%) (3)			4.20			4.13

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

(2) Includes loan fees of $1.2 million and $1.9 million for the three months ended June 30, 2010 and 2009, respectively, $2.6 million and $3.8 million for the six months ended June 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:

	June 30, 2010		December 31, 2009	
(dollars in thousands)	**Balance**	**% of total**	**Balance**	**% of total**
Real estate loans:				
Residential 1-4 family	$ 2,208,049	61.2	$ 2,319,738	62.5
Commercial real estate	277,299	7.7	255,458	6.9
Home equity line of credit	387,424	10.7	328,164	8.8
Residential land	84,314	2.4	96,515	2.6
Commercial construction	43,510	1.2	68,107	1.8
Residential construction	8,333	0.2	16,598	0.5
Total real estate loans, net	3,008,929	83.4	3,084,580	83.1
Commercial	527,464	14.6	542,686	14.6
Consumer	73,811	2.0	84,906	2.3
	3,610,204	100.0	3,712,172	100.0
Less: Allowance for loan losses	37,073		41,679	
Total loans, net	$ 3,573,131		$ 3,670,493	

The decrease in the total loan portfolio during the first six months of 2010 was primarily due to ASB s strategic decision to sell most of the salable residential loans it originated during the six month period ($115 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)	June 30, 2010	December 31, 2009
Real estate loans:		
Residential 1-4 family	$ 35,281	$ 31,686
Commercial real estate	717	344
Home equity line of credit	2,758	2,755
Residential land	19,038	25,162
Commercial construction		
Residential construction		325
Total real estate loans, net	57,794	60,272
Commercial	6,479	4,171
Consumer	709	715
Total nonperforming loans	64,982	65,158
Real estate owned:		
Residential 1-4 family	1,425	1,806
Residential land	2,339	2,153
Total real estate owned loans	3,764	3,959
Total nonperforming assets	$ 68,746	$ 69,117
Nonperforming assets to total loans and REO	1.90%	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:

	June 30, 2010		December 31, 2009	
(dollars in thousands)	Balance	% of total	Balance	% of total
Real estate loans:				
Residential 1-4 family	$ 4,744	61.2	$ 5,522	62.5
Commercial real estate	1,406	7.7	861	6.9
Home equity line of credit	3,722	10.7	4,679	8.8
Residential land	3,712	2.4	4,252	2.6
Commercial construction	1,962	1.2	3,068	1.8
Residential construction	8	0.2	19	0.5
Total real estate loans, net	15,554	83.4	18,401	83.1
Commercial	17,213	14.6	19,498	14.6
Consumer	3,026	2.0	2,590	2.3
	35,793	100.0	40,489	100.0
Unallocated	1,280		1,190	
Total allowance for loan losses	$ 37,073		$ 41,679	

Investment and mortgage-related securities. As of June 30, 2010, the bank s investment portfolio consisted of 49% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National

Mortgage Association (GNMA), 49% federal agency obligations and 2% 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.

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 June 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.

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 June 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 months ended June 30, 2010.Net interest income before provision for loan losses for the second quarter of 2010 decreased by $2.7 million, or 5%, when compared to the same quarter in 2009 as lower funding costs were more than offset by lower balances and yields on loans and investment and mortgage-related securities. Net interest margin increased from 4.16% in the second quarter of 2009 to 4.22% in the second quarter of 2010 due to the decrease in funding costs as ASB reduced its level of higher costing term certificates and other borrowings and attracted lower costing core deposits. The decrease in funding costs was partially offset by lower yields on the investment and mortgage-related securities portfolio as ASB sold its private-issue mortgage-related securities portfolio in the fourth quarter of 2009. The decrease in the average loan portfolio balance was due to a decrease in the average 1-4 family residential loan portfolio of $328 million as ASB sold most of its salable residential loan production during 2009 and the first half of 2010. In the second quarter of 2010, ASB started to retain a portion of its residential loan production. Average commercial, residential land and construction loan balances decreased by $40 million, $32 million and $22 million, respectively, due to paydowns in the portfolio. The average home equity line of credit portfolio increased by $65 million. The decrease in the average investment and mortgage-related securities portfolio was due to the sale of the private-issue mortgage-related securities portfolio in the fourth quarter of 2009. In the second quarter of 2010, to utilize its excess liquidity, ASB purchased securities, primarily federal agency obligations that had generally shorter durations. Average deposit balances decreased by $152 million compared to the second quarter of 2009. Average term certificate balances decreased by $445 million as ASB did not aggressively price its term certificate products because of the difficulty identifying investments that could be made with any excess liquidity. The average core deposit balance grew by $293 million, compared to the second quarter of 2009, as ASB introduced new deposit products and attracted core deposits to partially offset the outflow of term certificates. The shift in deposit mix from higher cost term 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. Average other borrowings decreased by $131 million primarily due to the payoff of maturing other borrowings.

During the second quarter of 2010, ASB recorded a provision for losses of $1.0 million compared to a provision for loan losses of $5.4 million in the first quarter of 2010 and $13.5 million in the second quarter of 2009. In the second quarter of 2010, ASB released loan loss reserves totaling $2.4 million on a commercial loan that was sold during the quarter and a commercial real estate construction loan that was successfully completed and fully leased and reclassified to an income property commercial real estate loan from a higher risk construction loan classification. The provision for losses in the second quarter of 2009 was impacted by the partial charge-off of a

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commercial loan, higher nonperforming residential lot loans and higher delinquencies in residential and consumer loans. Continued financial stress on ASB s customers may result in higher levels of delinquencies and losses.

Second quarter of 2010 noninterest income increased by $5.7 million, or 44%, when compared to the second quarter of 2009, primarily due to a $5.6 million other-than-temporary impairment charge on three mortgage-related securities in the second quarter of 2009.

Three months ended June 30 **(in thousands)**		**2010**		**2009**
Fee income on deposit liabilities	$	7,891	$	7,462
Fees from other financial services		6,649		6,443
Fee income on other financial products		1,735		1,628
Net gains (losses) on available-for-sale securities				(5,537)
Other income				
Gain on sale of loans		1,078		2,024
Bank-owned life insurance		988		991
Other		317		(18)
Total noninterest income	$	18,658	$	12,993

Noninterest expense for the second quarter of 2010 decreased by $4.7 million, or 11%, when compared to the second quarter of 2009. Lower occupancy, equipment and services expenses were the result of ASB s process improvement project, which reduced the bank s cost structure through improved processes and procedures, and improved the efficiency of the bank. 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 for the second quarter of 2009 included a special assessment of $2.3 million.

Three months ended June 30 **(in thousands)**		**2010**		**2009**
Compensation and benefits	$	18,907	$	17,991
Occupancy		4,216		5,922
Data processing		4,564		3,481
Services		1,845		3,801
Equipment		1,640		2,540
Other				
FDIC insurance premium		1,599		4,029
Marketing		370		544
Office supplies, printing and postage		1,127		888
Communication		512		578
Other		4,845		4,600
Total noninterest expense	$	39,625	$	44,374

Results six months ended June 30, 2010.Net interest income before provision for loan losses for the first six months of 2010 decreased by $6.4 million, or 6%, when compared to the same period in 2009 as lower funding costs were more than offset by lower balances and yields on loans and investment and mortgage-related securities. Net interest margin increased from 4.13% in the first six months of 2009 to 4.20% in the first six months of 2010 due to the decrease in funding costs as ASB reduced its level of higher costing term certificates and other borrowings and attracted lower costing core deposits. The decrease in funding costs was partially offset by lower yields on the investment and mortgage-related securities portfolio as ASB sold its private-issue mortgage-related securities portfolio in the fourth quarter of 2009 to reduce the overall credit risk of the bank 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. The decrease in the average loan portfolio balance was due to a decrease in the average 1-4 family residential loan portfolio of $392 million as ASB sold most of its salable residential loan production during 2009 and the first six month of 2010. In the second quarter of 2010, ASB started to retain a portion of its residential loan production. Average commercial, residential land and construction loan balances decreased by $43 million, $31 million and $21 million, respectively, due to paydowns in the portfolio. The average home equity lines of credit portfolio increased by $60 million. The decrease

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in the average investment and mortgage-related securities portfolios was primarily due to the sale of the private-issue mortgage-related securities portfolio in the fourth quarter of 2009. Average deposit balances decreased by $149 million compared to the first half of 2009. The average term certificate balance decreased by $462 million due to the outflow of term certificates throughout 2009 and the first six months of 2010 as ASB determined not to aggressively price its term certificate products because of the difficulty identifying investments that could be made with any excess liquidity. Average core deposit balances increased by $312 million as ASB introduced new deposit products and attracted core deposits to partially offset the outflow of term certificates. The shift in deposit mix from higher cost 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 decreased funding costs. Average other borrowings decreased by $198 million primarily due to the payoff of maturing other borrowings.

During the first six months of 2010, ASB recorded a provision for loan losses of $6.3 million primarily due to net charge-offs for 1-4 family and residential lot loans. In the second quarter of 2010, ASB released loan loss reserves totaling $2.4 million as described above (see Results three months ended June 30, 2010). During the first six months of 2009, ASB recorded a provision for loan losses of $21.8 million due to an increase in nonperforming residential lot loans and residential mortgages and the reclassification of one commercial loan. Continued financial stress on ASB s customers may result in higher levels of delinquencies and losses.

(in thousands)	Six months ended June 30 2010	2009	Year ended December 31 2009
Allowance for loan losses, January 1	$ 41,679	$ 35,798	$ 35,798
Provision for loan losses	6,349	21,800	32,000
Less: net charge-offs	10,955	15,076	26,119
Allowance for loan losses, end of period	$ 37,073	$ 42,522	$ 41,679
Ratio of allowance for loan losses, end of period, to end of period loans outstanding	1.03%	1.09%	1.12%
Ratio of net charge-offs during the period to average loans outstanding (annualized)	0.60%	0.74%	0.66%
Nonaccrual loans	$ 59,872	$ 60,773	$ 65,323

First six months of 2010 noninterest income increased by $7.3 million, or 25%, when compared to the first six months of 2009, primarily due to an other-than-temporary impairment charge on three mortgage-related securities in the second quarter of 2009 and higher deposit liability fees in 2010, partially offset by lower gain on sale of loans in 2010.

Six months ended June 30 (in thousands)	2010	2009
Fee income on deposit liabilities	$ 15,411	$ 14,173
Fees from other financial services	13,063	12,362
Fee income on other financial products	3,260	2,672
Net gains (losses) on available-for-sale securities		(5,537)
Other income		
Gain on sale of loans	2,120	3,532
Bank-owned life insurance	1,994	1,978
Other	662	77
Total noninterest income	$ 36,510	$ 29,257

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Noninterest expense for the first six months of 2010 decreased by $8.6 million, or 10%, when compared to the first six months of 2009. Lower compensation, occupancy, equipment and services expenses were the result of ASB s process improvement project, which reduced the bank s cost structure through improved processes and procedures, and improved the efficiency of the bank. 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 for the six months ended June 30, 2009 included a special assessment of $2.3 million.

Six months ended June 30 **(in thousands)**		**2010**		**2009**
Compensation and benefits	$	36,309	$	37,351
Occupancy		8,441		11,051
Data processing		8,902		6,668
Services		3,573		7,219
Equipment		3,349		5,330
Other				
FDIC insurance premium		3,258		5,501
Marketing		1,324		1,215
Office supplies, printing and postage		1,994		1,891
Communication		1,009		1,284
Other		9,436		8,675
Total noninterest expense	$	77,595	$	86,185

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 its level of regulatory capital and other considerations, these regulations could restrict the ability of ASB to compete with other institutions and to pay dividends to its shareholders. See the 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 Act also imposes new restrictions on the ability of a savings bank to pay dividends should it fail to remain a qualified thrift lender.

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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 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

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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 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 will have a negative impact on ASB s noninterest income, but the amount cannot be determined at this time.

FHLB of Seattle stock. As of June 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 $6.1 million for first quarter of 2010 compared to a net loss of $16.2 million for the same period in 2009. The FHLB of Seattle reported retained earnings of $59 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 six 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)	June 30, 2010	December 31, 2009	% change
Total assets	$ 4,875	$ 4,941	(1)
Available-for-sale investment and mortgage-related securities	624	433	44
Loans receivable, net	3,573	3,670	(3)
Deposit liabilities	4,002	4,059	(1)
Other bank borrowings	257	298	(14)

As of June 30, 2010, ASB was one of Hawaii s largest financial institutions based on assets of $4.9 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 June 30, 2010, ASB s unused FHLB borrowing capacity was approximately $1.5 billion. As of June 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 June 30, 2010 and December 31, 2009, ASB had $65.0 million and $65.2 million of nonperforming loans, respectively.

As of June 30, 2010 and December 31, 2009, ASB had $3.8 million and $4.0 million, respectively, of real estate acquired in settlement of loans.

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For the first six months of 2010, net cash provided by ASB s operating activities was $79 million. Net cash used during the same period by ASB s investing activities was $118 million, primarily due to purchases of investment and mortgage-related securities of $380 million and additions to premises and equipment of $5 million, offset by repayments of investment and mortgage-related securities of $204 million, a net decrease in loans receivable of $61 million and proceeds from the sale of real estate acquired in settlement of loans of $2 million. Net cash used in financing activities during this period was $122 million, primarily due to net decreases in deposit liabilities and retail repurchase agreements of $57 million and $41 million, respectively, and the payment of $23 million in common stock dividends.

ASB believes that a satisfactory regulatory capital position provides a basis for public confidence, affords protection to depositors, helps to ensure continued access to capital markets on favorable terms and provides a foundation for growth. FDIC regulations restrict the ability of financial institutions that are not well-capitalized to compete on the same terms as well-capitalized institutions, such as by offering interest rates on deposits that are significantly higher than the rates offered by competing institutions. As of June 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 13.0% (6.0%) and a total risk-based capital ratio of 14.1% (10.0%). OTS approval is required before ASB can make a capital distribution to HEI.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Credit risk for ASB is the risk that borrowers or issuers of securities will not be able to repay their obligations to the bank. Credit risk associated with ASB s lending portfolios is controlled through its underwriting standards, loan rating of commercial and commercial real estate loans, on-going monitoring by loan officers, credit review and quality control functions in these lending areas and adequate allowance for loan losses. Credit risk associated with the securities portfolio is mitigated through investment portfolio limits, experienced staff working with analytical tools, monthly fair value analysis and on-going monitoring and reporting such as investment watch reports and loss sensitivity analysis. Credit risk for ASB has risen as a result of the pronounced slowdown in the national and Hawaii economies and real estate markets. See Average balance sheet and net interest margin and Results six months ended June 30, 2010 above.

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 s Quantitative 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.

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

	June 30, 2010			December 31, 2009		
	Change in NII	NPV ratio	NPV ratio sensitivity *	Change in NII	NPV ratio	NPV ratio sensitivity *
Change in interest rates (basis points)	Gradual change	Instantaneous change		Gradual change	Instantaneous change	
+300	(0.2)%	12.18	(186)	(0.3)%	10.92%	(245)
+200	(0.3)	13.07	(97)	(0.3)	11.86	(151)
+100	(0.2)	13.75	(29)	(0.2)	12.72	(65)
Base		14.04			13.37	
-100	(0.7)	13.76	(28)	(0.9)	13.53	16
-200	**	**	**	**	**	**
-300	**	**	**	**	**	**

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

** For June 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) sensitivities as of June 30, 2010 and December 31, 2009 were very similar.

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

ASB s NPV ratio sensitivity measure as of June 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 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.

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Item 4. Controls and Procedures

HEI:

Changes in Internal Control over Financial Reporting

In May 2010, ASB converted several of its systems to Fiserv s bank platform system, including modules for branch automation, online banking, deposits, loans, electronic funds transfer, general ledger, accounts payable and fixed asset accounting. The implementation of these modules resulted in material changes to the Company s internal controls over financial reporting (as defined in Rules 13(a)-15(f) and 15(d)-15(f) under the Exchange Act). Therefore, ASB modified the design and documentation of internal control processes and procedures relating to the new system to replace existing internal controls over financial reporting, as appropriate. The system changes were undertaken to consolidate disparate automated and manual processes using a single, integrated approach and reduce service bureau expenses, and were not undertaken in response to any actual or perceived deficiencies in ASB s internal control over financial reporting.

During the second quarter of 2010, there were no other 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 June 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 June 30, 2010. Based on their evaluations, as of June 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 second 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 June 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 June 30, 2010. Based on their evaluations, as of June 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 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) For the six months ended June 30, 2010, HEI issued an aggregate of 28,000 shares of unregistered common stock pursuant to the HEI 1990 Nonemployee Director Stock Plan, as amended and restated effective May 6, 2008 (the HEI Nonemployee Director Plan). Under the HEI Nonemployee Director Plan, each HEI nonemployee director receives, in addition to an annual cash retainer, an annual stock grant of 1,800 shares of HEI common stock (2,000 shares for the first time grant to a new HEI director) and each nonemployee subsidiary director who is not also an HEI nonemployee director receives an annual stock grant of 1,000 shares of HEI common stock (1,000 shares for the first time grant to a new subsidiary director). The HEI Nonemployee Director Plan is currently the only plan for nonemployee directors and provides for annual stock grants and annual cash retainers for nonemployee directors of HEI and its subsidiaries.

HEI did not register the shares issued under the director stock plan since their issuance did not involve a sale as defined under Section 2(3) of the Securities Act of 1933, as amended. Participation by nonemployee directors of HEI and subsidiaries in the director stock plans is mandatory and thus does not involve an investment decision.

Item 5. Other Information

A. Ratio of earnings to fixed charges.

	Six months ended June 30		Years ended December 31				
	2010	2009	2009	2008	2007	2006	2005
HEI and Subsidiaries							
Excluding interest on ASB deposits	2.81	2.12	2.29	2.06	1.78	2.08	2.31
Including interest on ASB deposits	2.55	1.76	1.95	1.71	1.52	1.73	1.98
HECO and Subsidiaries	2.69	2.54	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, six months ended June 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, six months ended June 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)		**HAWAIIAN ELECTRIC COMPANY, INC.** (Registrant)	
By	/s/ Constance H. Lau Constance H. Lau President and Chief Executive Officer (Principal Executive Officer of HEI)	By	/s/ Richard M. Rosenblum Richard M. Rosenblum President and Chief Executive Officer (Principal Executive Officer of HECO)
By	/s/ James A. Ajello James A. Ajello Senior Financial Vice President, Treasurer and Chief Financial Officer (Principal Financial Officer of HEI)	By	/s/ Tayne S. Y. Sekimura Tayne S. Y. Sekimura Senior Vice President and Chief Financial Officer (Principal Financial Officer of HECO)
By	/s/ David M. Kostecki David M. Kostecki Vice President-Finance, Controller and Chief Accounting Officer (Principal Accounting Officer of HEI)	By	/s/ Patsy H. Nanbu Patsy H. Nanbu Controller (Principal Accounting Officer of HECO)
Date: August 9, 2010		Date: August 9, 2010	