HAWAIIAN ELECTRIC CO INC
Form 10-Q
May 10, 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 March 31, 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 o 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 May 7, 2010
Hawaiian Electric Industries, Inc. (Without Par Value)	93,174,549 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

Form 10-Q Quarter ended March 31, 2010

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Hawaiian Electric Industries, Inc. and Subsidiaries

Hawaiian Electric Company, Inc. and Subsidiaries

Form 10-Q Quarter ended March 31, 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). Former subsidiaries include ASB Service Corporation (dissolved in January 2004), ASB Realty Corporation (dissolved in May 2005) and AdCommunications, Inc. (dissolved in May 2007).
ASHI	American Savings Holdings, Inc., formerly HEI Diversified, 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.). Former subsidiaries of HEI (other than former subsidiaries of HECO and ASB and former subsidiaries of HEI sold or dissolved prior to 2004) include Hycap Management, Inc. (dissolution completed in 2007); Hawaiian Electric Industries Capital Trust I (dissolved and terminated in 2004)*, HEI Preferred Funding, LP (dissolved and terminated in 2004)*, Malama Pacific Corp. (discontinued operations, dissolved in June 2004), and HEI Power Corp. (discontinued operations, dissolved in 2006) and its dissolved subsidiaries. (*unconsolidated subsidiaries as of January 1, 2004).
	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
D&O	Decision and order
DG	Distributed generation
DOD	Department of Defense federal
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
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. Former subsidiaries include HECO Capital Trust I (dissolved and terminated in 2004)* and HECO Capital Trust II (dissolved and terminated in 2004)*. (*unconsolidated subsidiaries as of January 1, 2004).
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.). Former subsidiaries (other than those sold or dissolved prior to 2004) are listed under Company.
HEIII	HEI Investments, Inc. (formerly HEI Investment Corp.) (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
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 newly formed, 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 Economic 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, Iran s nuclear activities and potential H1N1 and avian flu pandemics;

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

- changes in laws, regulations, market conditions and other factors that result in changes in assumptions used to calculate retirement benefits costs and funding requirements and the fair value of ASB used to test goodwill for impairment;

- the impact of potential legislative and regulatory changes increasing oversight of and reporting by banks in response to the recent financial crisis and federal bailout of financial institutions;

- 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;

- 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, and the potential elimination of the Office of Thrift Supervision (OTS) and the grandfathering provisions of the Gramm-Leach-Bliley Act of 1999 (Gramm Act) that have permitted HEI to own ASB);

- decisions by the PUC in rate cases (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 in other proceedings 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 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 banking 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 ability of ASB to execute its performance improvement project, including the reduction of expenses through the conversion to the Fiserv Inc. bank platform system;

- 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)

Three months ended March 31 (in thousands, except per share amounts)		2010		2009
Revenues				
Electric utility	$	548,111	$	461,797
Bank		70,914		82,032
Other		15		(32)
		619,040		543,797
Expenses				
Electric utility		505,502		430,728
Bank		49,143		64,911
Other		3,688		3,500
		558,333		499,139
Operating income (loss)				
Electric utility		42,609		31,069
Bank		21,771		17,121
Other		(3,673)		(3,532)
		60,707		44,658
Interest expense other than on deposit liabilities and other bank borrowings		(20,381)		(17,833)
Allowance for borrowed funds used during construction		779		1,622
Allowance for equity funds used during construction		1,773		3,605
Income before income taxes		42,878		32,052
Income taxes		15,279		11,184
Net income		27,599		20,868
Preferred stock dividends of subsidiaries		473		473
Net income for common stock	$	27,126	$	20,395
Basic earnings per common share	$	0.29	$	0.23
Diluted earnings per common share	$	0.29	$	0.22
Dividends per common share	$	0.31	$	0.31
Weighted-average number of common shares outstanding		92,572		90,604
Dilutive effect of share-based compensation		276		88
Adjusted weighted-average shares		92,848		90,692

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)		March 31, 2010		December 31, 2009
Assets				
Cash and equivalents	$	341,330	$	502,443
Federal funds sold		702		1,479
Accounts receivable and unbilled revenues, net		233,885		241,116
Available-for-sale investment and mortgage-related securities		584,485		432,881
Investment in stock of Federal Home Loan Bank of Seattle		97,764		97,764
Loans receivable, net		3,623,127		3,670,493
Property, plant and equipment, net of accumulated depreciation of $1,970,087 and $1,945,482		3,091,190		3,088,611
Regulatory assets		426,146		426,862
Other		412,121		381,163
Goodwill, net		82,190		82,190
	$	8,892,940	$	8,925,002
Liabilities and stockholders equity				
Liabilities				
Accounts payable	$	189,149	$	186,994
Deposit liabilities		4,008,391		4,058,760
Short-term borrowings other than bank		60,238		41,989
Other bank borrowings		294,154		297,628
Long-term debt, net other than bank		1,364,847		1,364,815
Deferred income taxes		189,512		188,875
Regulatory liabilities		297,332		288,214
Contributions in aid of construction		323,090		321,544
Other		678,491		700,242
		7,405,204		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: 93,095,818 shares and 92,520,638 shares		1,277,333		1,265,157
Retained earnings		182,646		184,213
Accumulated other comprehensive loss, net of tax benefits		(6,536)		(7,722)
		1,453,443		1,441,648
	$	8,892,940	$	8,925,002

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity (unaudited)

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other comprehensive loss	Total
Balance, December 31, 2009	**92,521**	**$ 1,265,157**	**$ 184,213**	**$ (7,722)**	**$ 1,441,648**
Comprehensive income:					
Net income for common stock			27,126		27,126
Net unrealized gains on securities arising during the period, net of taxes of $696				1,053	1,053
Retirement benefit plans:					
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $609				958	958
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $526				(825)	(825)
Comprehensive income			27,126	1,186	28,312
Issuance of common stock, net	575	12,176			12,176
Common stock dividends ($0.31 per share)			(28,693)		(28,693)
Balance, March 31, 2010	**93,096**	**$ 1,277,333**	**$ 182,646**	**$ (6,536)**	**$ 1,453,443**
Balance, December 31, 2008	**90,516**	**$ 1,231,629**	**$ 210,840**	**$ (53,015)**	**$ 1,389,454**
Comprehensive income:					
Net income for common stock			20,395		20,395
Net unrealized gains on securities arising during the period, net of taxes of $5,711				8,649	8,649
Retirement benefit plans:					
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,862				2,918	2,918
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,668				(2,619)	(2,619)
Comprehensive income			20,395	8,948	29,343
Issuance of common stock, net	924	13,419			13,419
Common stock dividends ($0.31 per share)			(28,113)		(28,113)
Balance, March 31, 2009	**91,440**	**$ 1,245,048**	**$ 203,122**	**$ (44,067)**	**$ 1,404,103**

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)

Three months ended March 31 **(in thousands)**	**2010**	**2009**
Cash flows from operating activities		
Net income	$ 27,599	$ 20,868
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	39,798	38,494
Other amortization	1,565	594
Provision for loan losses	5,359	8,300
Loans receivable originated and purchased, held for sale	(78,685)	(171,390)
Proceeds from sale of loans receivable, held for sale	82,814	192,367
Changes in deferred income taxes	(129)	(2,530)
Changes in excess tax benefits from share-based payment arrangements	(43)	(21)
Allowance for equity funds used during construction	(1,773)	(3,605)
Increase in cash overdraft	681	
Changes in assets and liabilities		
Decrease in accounts receivable and unbilled revenues, net	7,231	101,743
Decrease (increase) in fuel oil stock	(26,506)	15,028
Increase (decrease) in accounts payable	2,155	(24,873)
Changes in prepaid and accrued income taxes and utility revenue taxes	(48,689)	(48,253)
Changes in other assets and liabilities	(1,508)	(11,045)
Net cash provided by operating activities	**9,869**	**115,677**
Cash flows from investing activities		
Available-for-sale investment and mortgage-related securities purchased	(170,385)	(109,364)
Principal repayments on available-for-sale investment and mortgage-related securities	48,338	180,918
Net decrease in loans held for investment	38,072	163,721
Proceed from sale of real estate acquired in settlement of loans	1,279	
Capital expenditures	(34,816)	(80,510)
Contributions in aid of construction	3,729	2,362
Other		86
Net cash provided by (used in) investing activities	**(113,783)**	**157,213**
Cash flows from financing activities		
Net decrease in deposit liabilities	(50,369)	(26,051)
Net increase in short-term borrowings with original maturities of three months or less	18,249	
Net decrease in retail repurchase agreements	(3,461)	(2,366)
Proceeds from other bank borrowings		310,000
Repayments of other bank borrowings		(552,517)
Proceeds from issuance of long-term debt		3,148
Changes in excess tax benefits from share-based payment arrangements	43	21
Net proceeds from issuance of common stock	5,557	7,365
Common stock dividends	(23,048)	(22,765)
Preferred stock dividends of subsidiaries	(473)	(473)
Decrease in cash overdraft		(5,865)
Other	(4,474)	(5,463)
Net cash used in financing activities	**(57,976)**	**(294,966)**
Net decrease in cash and equivalents and federal funds sold	(161,890)	(22,076)
Cash and equivalents and federal funds sold, beginning of period	503,922	183,435
Cash and equivalents and federal funds sold, end of period	**$ 342,032**	**$ 161,359**

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.

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 March 31, 2010 and December 31, 2009 and the results of its operations and cash flows for the three months ended March 31, 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 Accounting Standards Update (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 subsidiaries on the consolidated balance sheet from stockholders equity to mezzanine equity and the removal of preferred stock of subsidiaries 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 operating income, net income, earnings per share and cash flows.

2 • Segment financial information

(in thousands)	Electric Utility	Bank	Other	Total
Three months ended March 31, 2010				
Revenues from external customers	$ 548,075	$ 70,914	$ 51	$ 619,040
Intersegment revenues (eliminations)	36		(36)	
Revenues	548,111	70,914	15	619,040
Profit (loss)*	29,512	21,736	(8,370)	42,878
Income taxes (benefit)	10,961	8,000	(3,682)	15,279
Net income (loss)	18,551	13,736	(4,688)	27,599

Preferred stock dividends of subsidiaries	499		(26)	473
Net income (loss) for common stock	18,052	13,736	(4,662)	27,126
Assets (at March 31, 2010)	3,957,323	4,926,101	9,516	8,892,940
Three months ended March 31, 2009				
Revenues from external customers	$ 461,761	$ 82,032	$ 4	$ 543,797
Intersegment revenues (eliminations)	36		(36)	
Revenues	461,797	82,032	(32)	543,797
Profit (loss)*	23,083	17,092	(8,123)	32,052
Income taxes (benefit)	8,452	6,210	(3,478)	11,184
Net income (loss)	14,631	10,882	(4,645)	20,868
Preferred stock dividends of subsidiaries	499		(26)	473
Net income (loss) for common stock	14,132	10,882	(4,619)	20,395
Assets (at March 31, 2009)	3,793,747	5,159,756	6,453	8,959,956

* 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.

3 • Electric utility subsidiary

For HECO s consolidated financial information, including its commitments and contingencies, see pages 20 through 49.

4 • Bank subsidiary

Selected financial information

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

Consolidated Statements of Income Data (unaudited)

Three months ended March 31 (in thousands)	2010	2009
Interest and dividend income		
Interest and fees on loans	$ 49,745	$ 58,092
Interest and dividends on investment and mortgage-related securities	3,317	7,676
	53,062	65,768
Interest expense		
Interest on deposit liabilities	4,423	11,565
Interest on other borrowings	1,426	3,264
	5,849	14,829
Net interest income	47,213	50,939
Provision for loan losses	5,359	8,300
Net interest income after provision for loan losses	41,854	42,639
Noninterest income		
Fee income on deposit liabilities	7,520	6,711
Fees from other financial services	6,414	5,919
Fee income on other financial products	1,525	1,044
Other income	2,393	2,590
	17,852	16,264
Noninterest expense		
Compensation and employee benefits	17,402	19,360
Occupancy	4,225	5,129
Data processing	4,338	3,187
Services	1,728	3,418
Equipment	1,709	2,790
Other expense	8,568	7,927
	37,970	41,811
Income before income taxes	21,736	17,092
Income taxes	8,000	6,210
Net income	$ 13,736	$ 10,882

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

Consolidated Balance Sheets Data (unaudited)

(in thousands)	March 31, 2010	December 31, 2009
Assets		
Cash and equivalents	$ 308,291	$ 425,896
Federal funds sold	702	1,479
Available-for-sale investment and mortgage-related securities	584,485	432,881
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,623,127	3,670,493
Other	229,542	230,282
Goodwill, net	82,190	82,190
	$ 4,926,101	$ 4,940,985
Liabilities and stockholder s equity		
Deposit liabilities noninterest-bearing	$ 801,846	$ 808,474
Deposit liabilities interest-bearing	3,206,545	3,250,286
Other borrowings	294,154	297,628
Other	122,721	92,129
	4,425,266	4,448,517
Common stock	329,469	329,439
Retained earnings	175,391	172,655
Accumulated other comprehensive loss, net of tax benefits	(4,025)	(9,626)
	500,835	492,468
	$ 4,926,101	$ 4,940,985

Other assets

(in thousands)	March 31, 2010	December 31, 2009
Bank-owned life insurance	$ 114,465	$ 113,433
Premises and equipment, net	53,320	54,428
Prepaid expenses	23,752	24,353
Accrued interest receivable	14,831	15,247
Mortgage-servicing rights	4,521	4,200
Real estate acquired in settlement of loans, net	4,164	3,959
Other	14,489	14,662
	$ 229,542	$ 230,282

Other liabilities

(in thousands)	March 31, 2010	December 31, 2009

Accrued expenses	$	44,871	$	17,270
Federal and state income taxes payable		30,528		19,141
Cashier s checks		24,735		26,877
Advance payments by borrowers		6,515		10,989
Other		16,072		17,852
	$	122,721	$	92,129

Other borrowings consisted of securities sold under agreements to repurchase and advances from the Federal Home Loan Bank (FHLB) of Seattle of $229 million and $65 million, respectively, as of March 31, 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 March 31, 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:

	March 31, 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	$ 276,427	$ 267	$ (164)	$ 276,530	$ 104,091	$ 109	$ (156)	$ 104,044
Mortgage-related securities FNMA, FHLMC and GNMA	297,160	9,471		306,631	319,642	7,967	(88)	327,521
Municipal bonds	1,300	24		1,324	1,300	16		1,316
	$ 574,887	$ 9,762	$ (164)	$ 584,485	$ 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 (%)**
March 31, 2010										
Investment securities federal agency obligations	$ 276,427	1.23	$		$ 244,578	1.11	$ 21,849	2.13	$ 10,000	2.11
Mortgage-related securities FNMA, FHLMC and GNMA	297,160	3.78			4,832	2.34	129,615	3.79	162,713	3.81
Municipal bonds	1,300	2.27	500	1.92	800	2.50				
	$ 574,887	2.55	$ 500	1.92	$ 250,210	1.14	$ 151,464	3.55	$ 172,713	3.71
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

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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			
		Gross unrealized losses		Fair value		Gross unrealized losses		Fair value		Gross unrealized losses		Fair value
March 31, 2010												
Investment securities federal agency obligations	$	(164)	$	118,512	$		$		$	(164)	$	118,512
Mortgage-related securities FNMA, FHLMC and GNMA												
Municipal bonds												
	$	(164)	$	118,512	$		$		$	(164)	$	118,512
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 increases. 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 March 31, 2010.

The fair values of ASB s investment securities could decline if the current economic environment continues to deteriorate.

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 the quarter ended March 31, 2010, ASB s assessment rate was 15 basis points of deposits, or $1.5 million, compared to an assessment rate of 12 basis points of deposits, or $1.3 million for the same quarter in 2009.

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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.

Deposit insurance coverage. The Emergency Economic Stabilization Act of 2008 temporarily raised the basic limit on federal deposit insurance coverage from $100,000 to $250,000 per depositor, effective October 3, 2008. The basic deposit insurance coverage limit will return to $100,000 after December 31, 2013 for all interest bearing deposit categories except for individual retirement accounts and certain other retirement accounts, which will continue to be insured at $250,000 per owner. The FDIC has extended its Transaction Account Guarantee Program, which provides unlimited deposit insurance coverage for non-interest bearing deposit transaction accounts through December 31, 2010. Institutions currently participating in the program have the option to continue in the program or opt out. ASB has elected to not continue participating in the program after June 30, 2010.

5 • Retirement benefits

Defined benefit plans. For the first quarter of 2010, the utilities contributed $8.4 million and HEI contributed $0.2 million to their respective retirement benefit plans, compared to $9.4 million and $0.4 million, respectively, in the first quarter of 2009. The Company s current estimate of contributions to its retirement benefit plans in 2010 is $34 million ($33 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:

	Pension benefits		Other benefits	
Three months ended March 31 **(in thousands)**	**2010**	**2009**	**2010**	**2009**
Service cost	$ 6,953	$ 6,341	$ 1,123	$ 1,056
Interest cost	16,040	15,538	2,684	2,847
Expected return on plan assets	(17,194)	(14,276)	(2,752)	(2,215)
Amortization of unrecognized transition obligation	1	1		785
Amortization of prior service cost (gain)	(97)	(93)	(52)	3
Recognized actuarial loss (gain)	1,716	3,969	(1)	116
Net periodic benefit cost	7,419	11,480	1,002	2,592
Impact of PUC D&Os	3,008	(4,091)	1,288	(325)
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 10,427	$ 7,389	$ 2,290	$ 2,267

The Company recorded retirement benefits expense of $10 million and $7 million in the first quarters of 2010 and 2009, respectively, and charged the remaining amounts primarily to electric utility plant.

In the third quarter 2009, 1) the Company amended the executive life benefit plan to limit it to current participants and to freeze the executive life benefits at current levels and 2) HECO eliminated the electric discount benefit. The Company s cost for postretirement benefits other than pensions has been adjusted to reflect the negative plan amendments, which reduced benefits. The elimination of HECO s electric discount benefit has generated credits through other benefit costs and will generate credits over the next few years as the total negative amendment credit is amortized.

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

Defined contribution plan. 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

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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 equated to a 3.6% of eligible pay contribution for eligible participants. For the first quarters of 2010 and 2009, ASB s total expense for its employees participating in the HEIRSP and the new ASB 401(k) Plan combined was $0.8 million. For the first quarters of 2010 and 2009, ASB s cash contributions were $2.3 million and $0.5 million, respectively.

6 • Share-based compensation

Under the 1987 Stock Option and Incentive Plan, as amended (SOIP), HEI may issue an aggregate of 7.7 million shares of common stock (4.4 million available for issuance under outstanding and future grants and awards as of March 31, 2010) to officers and key employees as incentive stock options, nonqualified stock options (NQSOs), restricted stock awards, restricted stock units, stock appreciation rights (SARs), stock performance awards or dividend equivalents. HEI has issued new shares for NQSOs, restricted stock awards (nonvested stock), restricted stock units, stock performance awards, SARs and dividend equivalents under the SOIP. All information presented has been adjusted for the 2-for-1 stock split in June 2004.

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

Restricted stock awards generally become unrestricted four to five 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.

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. Restricted stock units expense has been recognized in accordance with the fair-value-based measurement method of accounting. Dividend equivalent rights on restricted stock units are accrued quarterly and are paid in cash at the end of the restriction period when the 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 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 portion of the LTIP awards payable in HEI common stock has been recognized in accordance with the fair-value-based measurement method of accounting for performance shares.

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

Three months ended March 31 **($ in millions)**	**2010**	**2009**
Share-based compensation expense (1)	0.6	0.4
Income tax benefit	0.2	0.1

(1) The Company has not capitalized any share-based compensation cost. For the first quarter of 2010, the estimated forfeiture rates were 41.0% for restricted stock awards, 5.9% for restricted stock units and 10.2% for performance shares.

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

March 31, 2010			**Outstanding & Exercisable**			
Year of grant		**Range of exercise prices**	**Number of options**	**Weighted-average remaining contractual life**		**Weighted-average exercise price**
2001	$	17.96	65,000	1.1	$	17.96
2002		21.68	122,000	1.9		21.68
2003		20.49	139,500	2.5		20.49
	$	17.96 21.68	326,500	2.0	$	20.43

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 March 31, 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 March 31 **($ in thousands, except prices)**		**2010**	**2009**
Shares expired		2,000	
Weighted-average exercise price	$	20.49	
Shares exercised		46,000	
Weighted-average exercise price	$	14.74	
Cash received from exercise	$	678	
Intrinsic value of shares exercised (1)	$	549	
Tax benefit realized for the deduction of exercises	$	214	

(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.

Since April 21, 2007, all NQSOs were vested.

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

March 31, 2010		Outstanding & Exercisable		
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	2.8	$ 26.02
2005	26.18	324,000	3.3	26.18
	$ 26.02 26.18	474,000	3.2	$ 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 March 31, 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 March 31 **($ in thousands, except prices)**		**2010**		**2009**
Shares forfeited				6,000
Weighted-average exercise price			$	26.18
Shares expired		6,000		
Weighted-average exercise price	$	26.18		
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.

Since April 7, 2009, all SARs were vested.

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 three months ended March 31, 2009 a total of 3,143 dividend equivalent shares for NQSO and 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:

	2010			**2009**		
Three months ended March 31	**Shares**		**(1)**	**Shares**		**(1)**
Outstanding, beginning of period	129,000	$	25.50	160,500	$	25.51
Granted						
Restrictions ended	(1,565)		25.97	(594)		24.11
Forfeited	(6,735)		25.75	(21,406)		25.75
Outstanding, end of period	120,700	$	25.48	138,500	$	25.48

(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 three months ended March 31, 2010 and 2009, total restricted stock vested had a fair value of $41,000 and $14,000, respectively.

The tax benefits realized for the tax deductions related to restricted stock awards were immaterial for the first quarters of 2010 and 2009.

As of March 31, 2010, there was $0.7 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 1.7 years.

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

Three months ended March 31	2010 Shares		(1)	2009 Shares		(1)
Outstanding, beginning of period	70,500	$	16.99			
Granted				70,500(2)	$	16.99
Restrictions ended	(250)	$	16.99			
Forfeited	(1,250)	$	16.99			
Outstanding, end of period	69,000	$	16.99	70,500	$	16.99

(1) Represents the weighted-average grant-date fair value per share. The grant date fair value of the 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.

For the three months ended March 31, 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 March 31, 2010, there was $0.8 million of total unrecognized compensation cost related to the nonvested restricted stock units. The cost is expected to be recognized over a weighted-average period of 2.8 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 grant 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 March 31	2010 Shares		(1)	2009 Shares		(1)
Outstanding, beginning of period	36,198	$	13.08			
Granted	97,191	$	18.69	36,198(2)	$	13.08

Vested						
Forfeited	(801)	$	13.08			
Outstanding, end of period	132,588	$	17.19	36,198	$	13.08

(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 $1.8 million based on the weighted-average grant date fair value per share of $18.69.

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 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:

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	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)	$18.69	$13.08

As of March 31, 2010, there was $1.7 million of total unrecognized compensation cost related to the nonvested shares linked to TRS. The cost is expected to be recognized over a weighted-average period of 2.5 years.

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

	2010			2009		
Three months ended March 31	Shares		(1)	Shares		(1)
Outstanding, beginning of period	24,131	$	13.34			
Granted	160,939	$	15.30	24,131(2)	$	13.34
Vested						
Forfeited	(535)	$	13.34			
Outstanding, end of period	184,535	$	15.05	24,131	$	13.34

(1) Weighted-average grant-date fair value per share based on the average price of HEI common stock on grant date less the present value of expected dividends to be paid over the performance period, using a discount rate equal to the risk-free interest rate based on the U.S. Treasury yield at the date of grant.

(2) Total weighted-average grant-date fair value of $0.5 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 $2.5 million based on the weighted-average grant date fair value per share of $15.30. The 2010-2012 LTIP goals with performance conditions include HEI consolidated net income, HECO consolidated ROACE, ASB net income and ASB ROA all based on 2-year averages (2011-2012).

As of March 31, 2010, there was $2.4 million of total unrecognized compensation cost related to the nonvested shares linked to performance conditions. The cost is expected to be recognized over a weighted-average period of 2.6 years.

7 • Commitments and contingencies

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

8 • Cash flows

Supplemental disclosures of cash flow information. For the three months ended March 31, 2010 and 2009, the Company paid interest (net of amounts capitalized and including bank interest) to non-affiliates amounting to $24 million and $25 million, respectively.

For the three months ended March 31, 2010 and 2009, the Company paid income taxes amounting to $7.9 million and $0.7 million, respectively.

Supplemental disclosures of noncash activities. Noncash increases in common stock for director and officer compensatory plans of the Company were $0.9 million and $0.5 million for the three months ended March 31, 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 $6 million and $5 million for the first quarters 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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9 • 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.

10 • Fair value of financial instruments

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

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

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

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

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

Deposit liabilities. The fair value of demand deposits, savings accounts, and money market deposits was the amount payable on demand at the reporting date. The fair value of fixed-maturity certificates of deposit was 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.

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

Off-balance sheet financial instruments. The fair value of loans serviced for others was 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:

	March 31, 2010		December 31, 2009	
(in thousands)	**Carrying or notional amount**	**Estimated fair value**	**Carrying or notional amount**	**Estimated fair value**
Financial assets				
Cash and equivalents	$ 341,330	$ 341,330	$ 502,443	$ 502,443
Federal funds sold	702	702	1,479	1,479
Available-for-sale investment and mortgage-related securities	584,485	584,485	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	3,623,127	3,728,618	3,670,493	3,760,954
Financial liabilities				
Deposit liabilities	4,008,391	4,012,571	4,058,760	4,063,888
Short-term borrowings other than bank	60,238	60,238	41,989	41,989
Other bank borrowings	294,154	307,203	297,628	307,154
Long-term debt	1,364,847	1,358,025	1,364,815	1,336,250
Off-balance sheet items				
HECO-obligated preferred securities of trust subsidiary	50,000	51,000	50,000	48,480

As of March 31, 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 value on such dates was $0.1 million and $0.2 million, respectively. As of March 31, 2010 and December 31, 2009, loans serviced by ASB for others had notional amounts of $611.2 million and $577.5 million and the estimated fair value of the servicing rights for such loans was $6.5 million and $5.6 million, respectively.

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Bank.

Assets measured at fair value on a recurring basis. While securities held in ASB s investment portfolio trade in active markets, they do not trade on listed exchanges nor do the specific holdings trade in quoted markets by dealers or brokers. All holdings are valued using market-based approaches that are based on exit prices that are taken from identical or similar market transactions, even in situations where trading volume may be low when compared with prior periods as has been the case during the current market disruption. Inputs to these valuation techniques reflect the assumptions that consider credit and nonperformance risk that market participants would use in pricing the asset based on market data obtained from independent sources. Available-for-sale securities were comprised of federal agency obligations and mortgage-backed securities and municipal bonds.

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

(in millions)	Fair value measurements using Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
March 31, 2010			
Available-for-sale securities			
Mortgage-related securities-FNMA, FHLMC and GNMA	$	$ 307	$
Investment securities-federal agency obligation		276	
Municipal bonds		1	
	$	$ 584	$
December 31, 2009			
Available-for-sale securities			
Mortgage-related securities-FNMA, FHLMC and GNMA	$	$ 328	$
Investment securities-federal agency obligation		104	
Municipal bonds		1	
	$	$ 433	$

Assets measured at fair value on a nonrecurring basis. From time to time, ASB 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 March 31, 2010 and December 31, 2009, there were no adjustments to fair value for ASB s assets measured at fair value on a nonrecurring basis in accordance with U.S. GAAP.

11 • Subsequent events

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. For example, a ratings downgrade of HEI s Issuer Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by Standard & Poor s (S&P) and Moody s Investors Service (Moody s), respectively) would result in a commitment fee increase of 5 basis points and an interest rate increase of 25 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1 by S&P or Moody s, respectively) would result in a commitment fee decrease of 10 basis points and an interest rate decrease of 25 basis points on any drawn amounts. The agreement 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

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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 20% as of March 31, 2010, as calculated under the agreement) and Consolidated Net Worth of $975 million (Net Worth of $1.5 billion as of March 31, 2010, as calculated under the agreement).

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.

12 • Earnings per share (EPS)

For the three months ended March 31, 2010, under the two-class method of computing basic and diluted EPS, distributed earnings were $0.31 per share and undistributed losses were $0.02 per share for both unvested restricted stock awards and unrestricted common stock. For the three months ended March 31, 2009, under the two-class method of computing basic and diluted EPS, distributed earnings were $0.31 per share and undistributed losses were $0.09 per share for both unvested restricted stock awards and unrestricted common stock.

As of March 31, 2010 and 2009, the antidilutive effects of SARs (474,000 shares of HEI common stock) and SARs and NQSOs (1,048,500 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.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

Three months ended March 31 (in thousands)	2010	2009
Operating revenues	$ 546,712	$ 459,285
Operating expenses		
Fuel oil	211,752	145,289
Purchased power	116,782	114,484
Other operation	59,244	62,397
Maintenance	27,053	26,163
Depreciation	38,642	36,424
Taxes, other than income taxes	51,791	45,735
Income taxes	11,041	8,544
	516,305	439,036
Operating income	30,407	20,249
Other income		
Allowance for equity funds used during construction	1,773	3,605
Other, net	1,241	2,368
	3,014	5,973
Interest and other charges		
Interest on long-term debt	14,383	11,912
Amortization of net bond premium and expense	667	675
Other interest charges	599	626
Allowance for borrowed funds used during construction	(779)	(1,622)
	14,870	11,591
Net income	18,551	14,631
Preferred stock dividends of subsidiaries	229	229
Net income attributable to HECO	18,322	14,402
Preferred stock dividends of HECO	270	270
Net income for common stock	$ 18,052	$ 14,132

HEI owns all 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)

(in thousands, except par value)	March 31, 2010	December 31, 2009
Assets		
Utility plant, at cost		
Land	$ 52,542	$ 52,530
Plant and equipment	4,711,777	4,696,257
Less accumulated depreciation	(1,872,332)	(1,848,416)
Construction in progress	145,118	132,980
Net utility plant	3,037,105	3,033,351
Current assets		
Cash and equivalents	31,510	73,578
Customer accounts receivable, net	127,059	133,286
Accrued unbilled revenues, net	84,762	84,276
Other accounts receivable, net	7,348	8,449
Fuel oil stock, at average cost	105,167	78,661
Materials and supplies, at average cost	37,156	35,908
Prepayments and other	14,917	16,201
Total current assets	407,919	430,359
Other long-term assets		
Regulatory assets	426,146	426,862
Unamortized debt expense	13,936	14,288
Other	72,217	73,532
Total other long-term assets	512,299	514,682
	$ 3,957,323	$ 3,978,392
Capitalization and liabilities		
Capitalization		
Common stock ($6 2/3 par value, authorized 50,000 shares; outstanding 13,787 shares)	$ 91,931	$ 91,931
Premium on capital stock	385,658	385,659
Retained earnings	829,938	827,036
Accumulated other comprehensive income, net of income taxes	1,839	1,782
Common stock equity	1,309,366	1,306,408
Cumulative preferred stock not subject to mandatory redemption	34,293	34,293
Long-term debt, net	1,057,847	1,057,815
Total capitalization	2,401,506	2,398,516
Current liabilities		
Short-term borrowings nonaffiliates	13,748	
Accounts payable	135,886	132,711
Interest and preferred dividends payable	21,736	21,223
Taxes accrued	104,770	156,092
Other	50,522	48,192
Total current liabilities	326,662	358,218
Deferred credits and other liabilities		
Deferred income taxes	178,792	180,603
Regulatory liabilities	297,332	288,214
Unamortized tax credits	57,441	56,870
Retirement benefits liability	294,955	296,623
Other	77,545	77,804
Total deferred credits and other liabilities	906,065	900,114
Contributions in aid of construction	323,090	321,544
	$ 3,957,323	$ 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:						
Net income for common stock				18,052		18,052
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $563					882	882
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $526					(825)	(825)
Comprehensive income				18,052	57	18,109
Common stock dividends				(15,150)		(15,150)
Common stock issue expenses			(1)			(1)
Balance, March 31, 2010	**13,787**	**$ 91,931**	**$ 385,658**	**$ 829,938**	**$ 1,839**	**$ 1,309,366**
Balance, December 31, 2008	**12,806**	**$ 85,387**	**$ 299,214**	**$ 802,590**	**$ 1,651**	**$ 1,188,842**
Comprehensive income:						
Net income for common stock				14,132		14,132
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,706					2,678	2,678
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,668					(2,619)	(2,619)
Comprehensive income				14,132	59	14,191
Common stock dividends				(10,536)		(10,536)
Balance, March 31, 2009	**12,806**	**$ 85,387**	**$ 299,214**	**$ 806,186**	**$ 1,710**	**$ 1,192,497**

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)

Three months ended March 31 (in thousands)		2010		2009
Cash flows from operating activities				
Net income	$	18,551	$	14,631
Adjustments to reconcile net income to net cash provided by (used in) operating activities				
Depreciation of property, plant and equipment		38,642		36,424
Other amortization		2,097		2,206
Changes in deferred income taxes		(1,834)		(1,290)
Changes in tax credits, net		776		2,514
Allowance for equity funds used during construction		(1,773)		(3,605)
Increase in cash overdraft		681		
Changes in assets and liabilities				
Decrease in accounts receivable		7,328		73,131
Decrease (increase) in accrued unbilled revenues		(486)		27,374
Decrease (increase) in fuel oil stock		(26,506)		15,028
Increase in materials and supplies		(1,248)		(1,277)
Increase in regulatory assets		(1,143)		(4,255)
Increase (decrease) in accounts payable		3,175		(15,848)
Changes in prepaid and accrued income and utility revenue taxes		(51,243)		(49,561)
Changes in other assets and liabilities		3,276		5,771
Net cash provided by (used in) operating activities		**(9,707)**		**101,243**
Cash flows from investing activities				
Capital expenditures		(34,189)		(80,315)
Contributions in aid of construction		3,729		2,362
Net cash used in investing activities		**(30,460)**		**(77,953)**
Cash flows from financing activities				
Common stock dividends		(15,150)		(10,536)
Preferred stock dividends of HECO and subsidiaries		(499)		(499)
Proceeds from issuance of long-term debt				3,148
Net increase (decrease) in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less		13,748		(12,211)
Decrease in cash overdraft				(5,865)
Other				(1)
Net cash used in financing activities		**(1,901)**		**(25,964)**
Net decrease in cash and equivalents		(42,068)		(2,674)
Cash and equivalents, beginning of period		73,578		6,901
Cash and equivalents, end of period	**$**	**31,510**	**$**	**4,227**

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.

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 March 31, 2010 and December 31, 2009 and the results of their operations and cash flows for the three months ended March 31, 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 March 31, 2010 and December 31, 2009 each consisted of $51.5 million of 2004 Debentures; $50.0 million of 2004 Trust Preferred Securities; and $1.5 million of trust common securities. Trust III s income statements for the three months ended March 31, 2010 and 2009 each consisted of $0.8 million of interest income received from the 2004 Debentures; $0.8 million of distributions to holders of the Trust Preferred Securities; and

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$25,000 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 March 31, 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 three months ended March 31, 2010 totaled $117 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $35 million, $39 million, $16 million and $11 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 years revenues. For the three months ended March 31, 2010 and 2009, HECO and its subsidiaries included approximately $49 million and $43 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 quarter of 2010, HECO and its subsidiaries contributed $8.4 million to their retirement benefit plans, compared to $9.4 million in the first quarter of 2009. HECO and its subsidiaries current estimate of contributions to their retirement benefit plans in 2010 is $33 million, compared to contributions of $24 million in 2009. In addition, HECO and its subsidiaries expect to pay directly $0.9 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 March 31 (in thousands)	Pension benefits 2010	Pension benefits 2009	Other benefits 2010	Other benefits 2009
Service cost	$ 6,610	$ 6,060	$ 1,088	$ 1,027
Interest cost	14,579	14,050	2,596	2,765
Expected return on plan assets	(15,324)	(12,673)	(2,715)	(2,178)
Amortization of unrecognized transition obligation			(2)	783
Amortization of prior service credit	(187)	(183)	(55)	
Recognized actuarial loss	1,685	3,671	3	114
Net periodic benefit cost	7,363	10,925	915	2,511
Impact of PUC D&Os	3,008	(4,091)	1,288	(325)
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 10,371	$ 6,834	$ 2,203	$ 2,186

HECO and its subsidiaries recorded retirement benefits expense of $10 million and $7 million for the first quarters of 2010 and 2009, respectively. The electric utilities charged a portion of the net periodic benefit costs to plant.

Postretirement benefits other than pensions. In the third quarter 2009, (1) the Company amended the executive life benefit plan to limit it to current participants and to freeze the executive life benefits at current levels and (2) HECO eliminated the electric discount benefit for retirees. The Company s cost for postretirement benefits other than pensions (OPEB) has been adjusted to reflect the plan amendment, which reduced benefits. The elimination of HECO s electric discount benefit will generate credits through other benefit costs over the next few years as the total amendment credit is amortized.

Balance sheet recognition of the funded status of retirement plans. In HELCO s 2006, HECO s 2007 and MECO s 2007 test year rate cases, the utilities and the Consumer Advocate proposed adoption of pension and OPEB tracking mechanisms, which are intended to smooth the impact to ratepayers of potential fluctuations in pension and OPEB costs.

In the PUC s 2007 interim decisions in HELCO s 2006 test year rate case and HECO and MECO s 2007 test year rate cases, the PUC allowed the utilities to adopt pension and OPEB tracking mechanisms. The amount of the net periodic pension cost (NPPC) and net periodic benefits costs (NPBC) to be recovered in rates is established by the PUC in each rate case. Under the utilities tracking mechanisms, any actual costs determined in accordance with U.S. generally accepted accounting principles that are over/under amounts allowed in rates are charged/credited to a regulatory asset/liability. The regulatory asset/liability for each utility will then be amortized over 5 years beginning with the respective utility s next rate case. Accordingly, all retirement benefit expenses (except for executive life and nonqualified pension plan expenses, which amounted to $1.5 million in 2009) determined in accordance with U.S. generally accepted accounting principles will be recovered.

Under the tracking mechanisms, amounts that would otherwise be recorded in accumulated other comprehensive income (AOCI) (excluding amounts for executive life and nonqualified pension plans), which amounts include the prepaid pension asset, net of taxes, as well as other pension and OPEB charges, are allowed to be reclassified as a regulatory asset, as those costs will be recovered in rates through the NPPC and NPBC in the future.

In the PUC s 2007 interim decision on HELCO s 2006 test year rate case, the PUC allowed HELCO to record a regulatory asset in the amount of $12.8 million (representing HELCO s prepaid pension asset and reflecting the accumulated pension contributions to its pension fund in excess of accumulated NPPC), which is included in rate base, and allowed recovery of that asset over a period of five years. HELCO is required to make contributions to the pension trust in the amount of the actuarially calculated NPPC that would be allowed without penalty by the tax laws.

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In the PUC s 2007 interim decisions on HECO and MECO s 2007 test year rate cases (and in its final decision on HECO s 2005 test year rate case), the PUC did not allow HECO and MECO to include their pension assets (representing the accumulated contributions to their pension fund in excess of accumulated NPPC), in their rate bases. However, under the tracking mechanisms, HECO and MECO are required to fund only the minimum level required under the law until their pension assets are reduced to zero, at which time HECO and MECO will make contributions to the pension trust in the amount of the actuarially calculated NPPC, except when limited by the ERISA minimum contribution requirements or the maximum deductible limitations on contributions imposed by the Internal Revenue Code (IRC).

The PUC s exclusion of HECO s and MECO s pension assets from rate base does not allow HECO and MECO to earn a return on the pension asset, but this exclusion does not result in the exclusion of any pension benefit costs from their rates. The pension asset is to be (or was, in the case of MECO) recovered in rates as NPPC is recorded in excess of contributions. As of March 31, 2010, MECO did not have any remaining pension asset, and HECO s pension asset had been reduced to $7 million.

The OPEB tracking mechanisms generally require the electric utilities to make contributions to the OPEB trust in the amount of the actuarially calculated NPBC, except when limited by material, adverse consequences imposed by federal regulations.

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. HECO will submit a PUC application for approval of the second amendment, such that the changes in fuel prices under the amendment would be included in HECO s ECAC. HECO has also agreed to ask the PUC to approve the application of the amended pricing retroactive to January 1, 2010.

The energy charge for energy purchased from Kalaeloa Partners, L.P. (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 amend the PPA to incorporate the amended fuel contract terms. If, after review, HECO consents, HECO will seek PUC approval for such a PPA amendment and to include the costs incurred under the PPA 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.

Public benefits fund (PBF). To fund energy efficiency programs, incentives, program administration, and other related program costs, as expended by a third-party administrator for the energy efficiency programs or by program contractors, which may include the utilities, a PBF was established that is funded by collecting 1% of electric utility revenues in 2009 and 2010; 1.5% in 2011 and 2012; and 2% thereafter. In 2010, the 1% will be assessed statewide, such that customers served under a given rate schedule will pay the same cents per kilowatthour (KWH) surcharge, regardless of service territory.

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.

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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. In December 2009, the PUC allowed for deferred treatment of Big Wind studies costs and such studies are proceeding as planned.

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 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.

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The Energy Agreement provided that system-wide caps on NEM should be removed after implementation of the FITs. Instead, all distributed generation 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.

Using biofuels. The Energy Agreement includes support of the development and use of renewable biofuels for electricity generation, including the testing of the technical feasibility of using biofuel or biofuel blends in HECO, HELCO and MECO generating units (which could avert major capital investment for new, replacement generation). In July 2009, HECO and MECO each filed applications for approval of 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. In October 2009, HECO filed a PUC application for approval of a purchase of 400,000 gallons of biodiesel to be used for operational testing and to collect emissions data for HECO Campbell Industrial Park combustion turbine No. 1 (CIP CT-1). In December 2009, the parties and participants in the respective dockets recommended the PUC approve the biodiesel fuel supply contract applications. Also in December of 2009, HECO filed an application for approval of a two-year biodiesel supply contract with Renewable Energy Group Marketing and Logistics, LLC (REG) primarily for CIP CT-1.

On March 31, 2010, HECO 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. Proposals must be submitted by June 18, 2010. A contract could be awarded to supply some or all of CIP CT-1 requirements upon expiration of the biodiesel supply contract with REG.

HECO expects to issue an all-fuels RFP in the fourth quarter of 2010 to solicit proposals for fuel to include CIP CT-1 biodiesel requirements that are not fulfilled through a contract for local biofuels and/or upon expiration of the term of the biodiesel supply contract with REG.

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

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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 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) promoting greater use of solar energy; (b) 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; (c) improving and expanding load management and demand response programs that allow the utilities to control customer loads to improve grid reliability and cost management; (d) 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; (e) 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; (f) delinking prices paid under all new renewable energy contracts from oil prices; and (g) 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 March 31, 2010, HECO and its subsidiaries had recognized $323 million of revenues with respect to interim orders ($318 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 (with capitalized and deferred costs accumulated through March 31, 2010 noted in parentheses) whose costs have not yet been allowed in rate base by a final PUC order include HECO s CIP CT-1 and transmission line ($193 million), HECO s East Oahu Transmission Project ($53 million), HELCO s ST-7 ($90 million) and HECO s Customer Information System (CIS) ($25 million).

CIP CT-1 and transmission line. HECO has built a new 110 MW simple cycle combustion turbine (CT) generating unit at CIP and has added an additional 138 kilovolt transmission line to transmit power from generating units at CIP to the rest of the Oahu electric grid (collectively, the Project). Current plans are for the CT to be run primarily as a peaking unit and to be fueled by biodiesel, when a biodiesel operational supply contract is approved by the PUC.

In December 2006, HECO filed with the PUC an agreement with the Consumer Advocate in which HECO committed to use 100% biofuels in its new plant and to take the steps necessary for HECO to reach that goal.

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In its 2009 test year rate case, HECO requested inclusion of CIP CT-1 costs in rate base when the unit is placed in service, but the PUC did not grant the request in its first interim D&O issued in July 2009, indicating that the record did not yet demonstrate that the unit would be in service by the end of 2009. Subsequently, CIP CT-1 completed all utility requirements for system operation on August 3, 2009, including synchronizing into the grid and performing all operational tests necessary for commercial operation. In October 2009, a process was established with PUC approval to allow HECO to use CIP CT-1 for critical load purposes. On December 21, 2009, HECO entered into a two-year contract with REG to supply biodiesel for the generating unit, subject to PUC approval, which HECO applied for on December 22, 2009. In April 2010, the Consumer Advocate filed its Statement of Position supporting HECO s request for approval. In April 2010, HECO purchased 500,000 gallons of biodiesel under the REG contract. HECO is still awaiting a PUC D&O on its request for approval of the REG contract.

In February 2010, the PUC issued a second interim D&O in the HECO 2009 test year rate case granting HECO an additional increase of $12.7 million in annual revenues to recover the costs of CIP CT-1 and related transmission improvements. The second interim D&O also stated that until HECO can secure its biodiesel fuel supply, the PUC finds it appropriate to temporarily allow HECO to operate CT-1 as a diesel peaking unit (i.e., be utilized on more than just an emergency basis). In March 2010, the Department of Health of the State of Hawaii (DOH) approved CIP CT-1 s use of biodiesel and biodiesel/diesel blends with up to 1% diesel.

As of March 31, 2010, HECO s cost estimate for the Project was $196 million (of which $193 million had been incurred, including $9 million of allowance for funds during construction (AFUDC)). To the extent actual project costs are higher than the $163 million estimate included in the 2009 test year rate case, HECO plans to seek recovery in a future proceeding. Management believes no adjustment to project costs is required as of March 31, 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 kilovolt (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 (then estimated at $56 million $42 million for Phase 1 and $14 million for Phase 2) for an EOTP, revised to use a 46 kV system and a modified route, none of which is in conservation district lands.

In October 2007, the PUC issued a final D&O approving HECO s request to expend funds for the EOTP, 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 is currently in construction and projected to be completed in 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.

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As of March 31, 2010, the accumulated costs recorded for the EOTP amounted to $53 million ($51 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) $18 million of planning, permitting and construction costs incurred after the denial of the permit and (iii) $23 million for AFUDC. Management believes no adjustment to project costs is required as of March 31, 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.

There were a number of environmental and other permitting challenges to construction of the units, including several lawsuits, which resulted in significant delays. However, in 2003, all but one of the parties actively opposing the plant expansion project entered into a settlement agreement with HELCO and several Hawaii regulatory agencies (the Settlement Agreement) intended in part to permit HELCO to complete CT-4 and CT-5. The Settlement Agreement required HELCO to undertake a number of actions, which have been completed or are ongoing. As a result of the final resolution of various proceedings due primarily to the Settlement Agreement, there are no pending lawsuits involving the project.

CT-4 and CT-5 became operational in mid-2004 and currently can be operated as required to meet HELCO s system needs, but additional efforts have been ongoing to achieve compliance with the night-time noise standard in the Settlement Agreement and/or to modify the standard.

HELCO s capitalized costs for CT-4 and CT-5 and related supporting infrastructure amounted to $110 million. HELCO sought recovery of these costs as part of its 2006 test year rate case.

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 March 31, 2010, HELCO s cost estimate for ST-7 was $92 million (of which $90 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 March 31, 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. On August 26, 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 a D&O filed on May 3, 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 an 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.

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 because of Peace s failure to satisfy the project schedule. In July 2008, HECO notified the PUC that, due to cost overruns and other issues, the total estimated cost of the project had increased to $39.5 million and the transition to the new CIS would be postponed to 2009. In April 2009, HECO notified the PUC that, due to the delays and other issues, a transition to the new CIS was no longer expected to occur in 2009. Through August 2009, HECO attempted to work with Peace to develop a plan to minimize additional delay and complete installation of the new CIS using the Peace software, despite Peace s failure to cure the breaches identified by HECO in June 2008. However, on August 31, 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. HECO contends the lawsuit is without merit. On October 5, 2009, HECO filed its response to the Peace complaint and also filed a counterclaim against Peace for breach of contract and a third-party claim against Peace s former owner, First Data Corporation, for tortious interference with HECO s contract. Peace, First Data Corporation and HECO are currently discussing possible settlement of this litigation.

The CIS project will continue with HECO s selection of a new software vendor and system integrator expected to be made before the end of the second quarter of 2010. As of March 31, 2010, the accumulated deferred and capital costs recorded for the CIS amounted to $25 million. Management believes no adjustment to project costs is required as of March 31, 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 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, preliminary oil removal, and are currently finalizing remedial design tasks, which they anticipate will be completed 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 March 31, 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 March 31, 2010, the remaining accrual (amounts expensed less amounts expended) for the Iwilei unit was $1.5 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. States were to develop BART implementation plans and schedules in accordance with the amended regional haze rule by December 2007. If a state does not develop a BART implementation plan, the EPA is required to develop a federal implementation plan (FIP) by 2011.

On May 4, 2010, HELCO received notification that the EPA has determined that emissions from the Hill Power Plant decrease the visibility at Hawaii Volcanoes National Park and Haleakala National Park. The EPA requested that HELCO conduct a BART analysis by August 28, 2010. Alternatively, HELCO may notify the EPA that it will not perform the analysis, in which case the EPA would perform the analysis. The BART determination is made on a case-by-case basis taking into account a number of factors, including cost and the degree of visibility improvement that may reasonably be anticipated as a result of employing BART. In the letter, the EPA also indicated that it will be developing a FIP for Hawaii using the notice and comment rulemaking process.

The EPA also advised that it plans to evaluate HELCO s Puna Power Plant and Shipman Power Plant emissions in the context of a long-term strategy for making reasonable progress toward improvement of visibility in the national parks. If any of HELCO s generating units are ultimately required to install post-combustion control technologies 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.

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Hazardous Air Pollutant (HAP) Control Industrial, Commercial and Institutional Boilers. On April 30, 2010, the EPA issued proposed rules governing HAP from industrial, commercial and institutional boilers at area sources of HAP. The proposed rules would apply to steam generating units operated by the utilities that do not qualify as EGUs, which may include oil-fired generating units at HECO s Honolulu Power Plant, HELCO units at the Hill, Shipman and Puna Power Plants, and MECO units at the Kahului Power Plant. For such units, the proposed rules could require control of carbon monoxide emissions above a proposed standard, installation and operation of continuous emission monitoring systems, and institution of work practices designed to increase efficiency and thereby reduce HAP emissions. The utilities have begun to evaluate the proposed rules. If control equipment is required for such units, the compliance 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 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 currently 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 (S. 1733). S. 1733 also includes cap and trade

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provisions to reduce GHG emissions. 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 June 30, 2009, the EPA granted the California Air Resources Board s request for a waiver from CAA preemption to enforce GHG emission standards for motor vehicles. 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. On September 28, 2009, the EPA and the National Transportation Safety Administration jointly proposed federal GHG emission standards for motor vehicles (Tailpipe Rule).

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 GHGs. However, on October 27, 2009, the Federal Register published the EPA s proposed Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Tailoring Rule (GHG Tailoring Rule) that would create a new emissions threshold for GHG emissions from new and existing facilities. The proposed rule would phase in applicability thresholds for both PSD and Title V programs for sources of GHG emissions. The first phase would last for six years. The EPA would conduct, if appropriate, another rulemaking by the end of the sixth year to revise applicability and significance level thresholds and other streamlining techniques. States may need to increase fees to cover the increased level of activity caused by this rule. If adopted in its current form, the proposed tailoring rule would require 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 following the effective date of the final rule.

On April 2, 2010, the EPA published in the Federal Register its final interpretation of when a pollutant becomes subject to regulation for PSD program purposes. Under the final interpretation, a pollutant becomes subject to control when a regulation requires actual control of the newly regulated pollutant, and then, only when the regulatory requirement takes effect. In conjunction with this interpretation, the EPA has stated that the PSD program will apply to GHG emissions on January 2, 2011 because it is the date the 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 ultimately adopted 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. Implementation of actions included in the Energy Agreement under the HCEI can further help achieve reduction or elimination of GHG emissions. 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.

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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 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.

By letter to HELCO dated June 15, 2009, Tawhiri requested binding arbitration as provided for under the provisions of the RAC on the issue of HELCO s curtailment of the wind farm output to 10 MW between October 9, 2007 and July 3, 2008. Tawhiri sought alleged damages for lost production in the amount of $13 million, plus unspecified damages for lost production tax credits, overhead losses, and consultant and legal fees. HELCO responded to Tawhiri s arbitration request on July 2, 2009, stating, among other points, that the curtailment was justified because Tawhiri failed to meet the low voltage ride-through requirements of the RAC and improperly disconnected from the grid on October 9, 2007. On March 1, 2010, a panel of three neutral arbitrators issued a final award and order, which provided that: (1) each party is to bear its own costs and expenses of the arbitration; (2) Tawhiri s claims with respect to the curtailment on October 9,

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2007 are denied and Tawhiri does not recover any damages for the curtailment on that date; (3) with respect to the length of the curtailment, which lasted 9 months, Tawhiri is awarded $500,000 in damages to be paid by HELCO, unless the parties agree otherwise or action under Hawaii law intervenes; (4) the final award and order is in full resolution of all claims submitted to the arbitration; and (5) the arbitrators recommend (although this is not binding on the parties) that HELCO and Tawhiri meet to negotiate and resolve their differences in interpretation and application of the under-voltage ride through provisions of the RAC to avoid future disputes. Pursuant to the RAC, the decision of the arbitrators is not binding on the parties until the decision is confirmed by order of a court of competent jurisdiction, which confirmation was requested by HECO on April 1, 2010.

In addition to the curtailment issue, HELCO and Tawhiri have disputes relating to HECO s ownership and possessory interests in the switching station and reimbursement of certain interconnection costs (arbitration hearings scheduled to start in June 2010) and reconciliation of transmission line losses (which has 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 a 5-year period (2010 to 2014). In accordance with accounting principles for asset retirement and environmental obligations, HECO recorded an asset retirement obligation in September 2009. As of March 31, 2010, HECO s asset retirement obligation was $24 million.

Collective bargaining agreements. As of March 31, 2010, approximately 56% 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 costs and revenues lost from business interruption, their results of operations and financial condition could be materially adversely impacted. Also, certain insurance has substantial deductibles , limits on the maximum amounts that may be recovered and exclusions or limitations of coverage for claims related to certain perils. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business, each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, HECO, HELCO and MECO could incur losses in amounts that would have a material adverse effect on their results of operations and financial condition.

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6 • Cash flows

Supplemental disclosures of cash flow information. For the three months ended March 31, 2010 and 2009, HECO and its subsidiaries paid interest amounting to $14 million and $8 million, respectively.

For the three months ended March 31, 2010, HECO and its subsidiaries paid income taxes amounting to $7.8 million. For the three months ended March 31, 2009, HECO and its subsidiaries received an income tax refund amounting to $2.0 million.

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 $1.8 million and $3.6 million for the three months ended March 31, 2010 and 2009, respectively.

7 • Recent accounting pronouncements and interpretations

For a discussion of recent accounting pronouncements and interpretations, see Note 9 of HEI s Notes to Consolidated Financial Statements.

8 • Fair value of financial instruments

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:

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Cash and 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.

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

(in thousands)	March 31, 2010 Carrying amount	March 31, 2010 Estimated fair value	December 31, 2009 Carrying amount	December 31, 2009 Estimated fair value
Financial assets				
Cash and equivalents	$ 31,510	$ 31,510	$ 73,578	$ 73,578
Financial liabilities				
Long-term debt, net, including amounts due within one year	1,057,847	1,040,675	1,057,815	1,018,900
Off-balance sheet item				
HECO-obligated preferred securities of trust subsidiary	50,000	51,000	50,000	48,480

9 • Subsequent events

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. 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 Capitalization Ratio to exceed 65% (ratio of 48% for HELCO and 44% for MECO as of March 31, 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 March 31, 2010, as calculated under the agreement).

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 expenditure, 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. HECO expects to file with the PUC in the summer of 2010 an application seeking approval to extend the termination date of its credit agreement from May 6, 2011, to May 7, 2013.

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

Three months ended March 31 (in thousands)		2010		2009
Operating income from regulated and nonregulated activities before income taxes (per HEI consolidated statements of income)	$	42,609	$	31,069
Deduct:				
Income taxes on regulated activities		(11,041)		(8,544)
Revenues from nonregulated activities		(1,399)		(2,512)
Add:				
Expenses from nonregulated activities		238		236
Operating income from regulated activities after income taxes (per HECO consolidated statements of income)	$	30,407	$	20,249

11 • Consolidating financial information

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

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

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Three months ended March 31, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and Elimina-tions	HECO Consolidated
Operating revenues	$ 376,104	89,032	81,576				$ 546,712
Operating expenses							
Fuel oil	146,342	23,479	41,931				211,752
Purchased power	85,861	25,702	5,219				116,782
Other operation	41,626	9,017	8,601				59,244
Maintenance	17,074	3,395	6,584				27,053
Depreciation	21,913	9,126	7,603				38,642
Taxes, other than income taxes	35,723	8,328	7,740				51,791
Income taxes	7,905	2,647	489				11,041
	356,444	81,694	78,167				516,305
Operating income	19,660	7,338	3,409				30,407
Other income							
Allowance for equity funds used during construction	1,559	95	119				1,773
Equity in earnings of subsidiaries	5,293					(5,293)	
Other, net	1,114	115	45	(2)	(5)	(26)	1,241
	7,966	210	164	(2)	(5)	(5,319)	3,014
Interest and other charges							
Interest on long-term debt	9,130	2,985	2,268				14,383
Amortization of net bond premium and expense	433	117	117				667
Other interest charges	425	101	99			(26)	599
Allowance for borrowed funds used during construction	(684)	(49)	(46)				(779)
	9,304	3,154	2,438			(26)	14,870
Net income (loss)	18,322	4,394	1,135	(2)	(5)	(5,293)	18,551
Preferred stock dividend of subsidiaries		134	95				229
Net income (loss) attributable to HECO	18,322	4,260	1,040	(2)	(5)	(5,293)	18,322
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 18,052	4,260	1,040	(2)	(5)	(5,293)	$ 18,052

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Three months ended March 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and elimina-tions	HECO consoli-dated
Operating revenues	$ 305,461	84,631	69,193				$ 459,285
Operating expenses							
Fuel oil	98,931	15,764	30,594				145,289
Purchased power	75,845	33,407	5,232				114,484
Other operation	43,076	9,994	9,327				62,397
Maintenance	16,658	5,938	3,567				26,163
Depreciation	20,797	8,251	7,376				36,424
Taxes, other than income taxes	30,683	8,246	6,806				45,735
Income taxes	6,229	850	1,465				8,544
	292,219	82,450	64,367				439,036
Operating income	13,242	2,181	4,826				20,249
Other income							
Allowance for equity funds used during construction	2,702	742	161				3,605
Equity in earnings of subsidiaries	3,960					(3,960)	
Other, net	1,878	569	81	(7)	(7)	(146)	2,368
	8,540	1,311	242	(7)	(7)	(4,106)	5,973
Interest and other charges							
Interest on long-term debt	7,668	1,976	2,268				11,912
Amortization of net bond premium and expense	403	151	121				675
Other interest charges	477	207	88			(146)	626
Allowance for borrowed funds used during construction	(1,168)	(388)	(66)				(1,622)
	7,380	1,946	2,411			(146)	11,591
Net income (loss)	14,402	1,546	2,657	(7)	(7)	(3,960)	14,631
Preferred stock dividend of subsidiaries		134	95				229
Net income (loss) attributable to HECO	14,402	1,412	2,562	(7)	(7)	(3,960)	14,402
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 14,132	1,412	2,562	(7)	(7)	(3,960)	$ 14,132

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

March 31, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and Elimina-tions	HECO Consolidated
Assets							
Utility plant, at cost							
Land	$ 43,088	5,108	4,346				$ 52,542
Plant and equipment	2,842,784	998,351	870,642				4,711,777
Less accumulated depreciation	(1,091,311)	(386,475)	(394,546)				(1,872,332)
Construction in progress	126,901	10,718	7,499				145,118
Net utility plant	1,921,462	627,702	487,941				3,037,105
Investment in wholly owned subsidiaries, at equity	462,276					(462,276)	
Current assets							
Cash and equivalents	27,228	3,407	765	95	15		31,510
Advances to affiliates	15,700		8,000			(23,700)	
Customer accounts receivable, net	84,486	22,995	19,578				127,059
Accrued unbilled revenues, net	58,663	13,804	12,295				84,762
Other accounts receivable, net	8,392	2,775	695			(4,514)	7,348
Fuel oil stock, at average cost	75,922	11,722	17,523				105,167
Materials & supplies, at average cost	19,593	4,305	13,258				37,156
Prepayments and other	6,592	4,245	4,080				14,917
Total current assets	296,576	63,253	76,194	95	15	(28,214)	407,919
Other long-term assets							
Regulatory assets	313,243	58,572	54,331				426,146
Unamortized debt expense	9,159	2,615	2,162				13,936
Other	45,871	9,820	16,526				72,217
Total other long-term assets	368,273	71,007	73,019				512,299
	$ 3,048,587	761,962	637,154	95	15	(490,490)	$ 3,957,323
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,309,366	241,406	220,766	92	12	(462,276)	$ 1,309,366
Cumulative preferred stock not subject to mandatory redemption	22,293	7,000	5,000				34,293
Long-term debt, net	672,218	211,255	174,374				1,057,847
Total capitalization	2,003,877	459,661	400,140	92	12	(462,276)	2,401,506
Current liabilities							
Short-term borrowings-nonaffiliates	13,748						13,748
Short-term borrowings-affiliate	8,000	15,700				(23,700)	
Accounts payable	105,196	17,302	13,388				135,886
Interest and preferred dividends payable	13,558	4,325	3,866			(13)	21,736
Taxes accrued	62,833	24,510	17,427				104,770
Other	27,511	12,862	14,644	3	3	(4,501)	50,522
Total current liabilities	230,846	74,699	49,325	3	3	(28,214)	326,662
Deferred credits and other liabilities							
Deferred income taxes	140,251	25,692	12,849				178,792
Regulatory liabilities	204,073	53,521	39,738				297,332
Unamortized tax credits	32,065	12,914	12,462				57,441

Retirement benefits liability		220,304	35,215	39,436					294,955
Other		36,636	30,109	10,800					77,545
Total deferred credits and other liabilities		633,329	157,451	115,285					906,065
Contributions in aid of construction		180,535	70,151	72,404					323,090
	$	3,048,587	761,962	637,154	95	15	(490,490)	$	3,957,323

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

December 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and Elimina-tions	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 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)

Three months ended March 31, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and elimina-tions	HECO consoli-dated
Balance, December 31, 2009	$ 1,306,408	240,576	221,319	94	17	(462,006)	$ 1,306,408
Comprehensive income:							
Net income (loss) for common stock	18,052	4,260	1,040	(2)	(5)	(5,293)	18,052
Retirement benefit plans:							
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes	882	189	161			(350)	882
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits	(825)	(185)	(154)			339	(825)
Comprehensive income (loss)	18,109	4,264	1,047	(2)	(5)	(5,304)	18,109
Common stock dividends	(15,150)	(3,434)	(1,600)			5,034	(15,150)
Common stock issue expenses	(1)						(1)
Balance, March 31, 2010	$ 1,309,366	241,406	220,766	92	12	(462,276)	$ 1,309,366

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Common Stock Equity (unaudited)

Three months ended March 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and elimina-tions	HECO consoli-dated
Balance, December 31, 2008	$ 1,188,842	221,405	215,382	105	141	(437,033)	$ 1,188,842
Comprehensive income:							
Net income (loss) for common stock	14,132	1,412	2,562	(7)	(7)	(3,960)	14,132
Retirement benefit plans:							
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes	2,678	409	325			(734)	2,678
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits	(2,619)	(405)	(319)			724	(2,619)
Comprehensive income (loss)	14,191	1,416	2,568	(7)	(7)	(3,970)	14,191

Common stock dividends		(10,536)		(1,717)			1,717		(10,536)
Balance, March 31, 2009	$	1,192,497	222,821	216,233	98	134	(439,286)	$	1,192,497

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Three months ended March 31, 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)	$ 18,322	4,394	1,135	(2)	(5)	(5,293)	$ 18,551
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(5,318)					5,293	(25)
Common stock dividends received from subsidiaries	5,059					(5,034)	25
Depreciation of property, plant and equipment	21,913	9,126	7,603				38,642
Other amortization	1,124	862	111				2,097
Deferred income taxes	(939)	(294)	(601)				(1,834)
Tax credits, net	804	60	(88)				776
Allowance for equity funds used during construction	(1,559)	(95)	(119)				(1,773)
Increase in cash overdraft			681				681
Changes in assets and liabilities:							
Decrease in accounts receivable	2,454	1,026	463			3,385	7,328
Decrease (increase) in accrued unbilled revenues	(641)	(156)	311				(486)
Decrease (increase) in fuel oil stock	(26,075)	918	(1,349)				(26,506)
Decrease (increase) in materials and supplies	(1,215)	(299)	266				(1,248)
Increase in regulatory assets	(771)	(293)	(79)				(1,143)
Increase (decrease) in accounts payable	2,123	(67)	1,119				3,175
Changes in prepaid and accrued income and utility revenue taxes	(38,496)	(6,680)	(6,067)				(51,243)
Changes in other assets and liabilities	3,883	3,533	(755)	(1)	1	(3,385)	3,276
Net cash provided by (used in) operating activities	(19,332)	12,035	2,631	(3)	(4)	(5,034)	(9,707)
Cash flows from investing activities:							
Capital expenditures	(25,488)	(4,212)	(4,489)				(34,189)
Contributions in aid of construction	1,339	1,546	844				3,729
Advances from (to) affiliates	4,400		3,000			(7,400)	
Net cash used in investing activities	(19,749)	(2,666)	(645)			(7,400)	(30,460)
Cash flows from financing activities:							
Common stock dividends	(15,150)	(3,434)	(1,600)			5,034	(15,150)
Preferred stock dividends of HECO and subsidiaries	(270)	(134)	(95)				(499)

Net increase (decrease) in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	10,748	(4,400)				7,400	13,748
Net cash used in financing activities	(4,672)	(7,968)	(1,695)			12,434	(1,901)
Net increase (decrease) in cash and equivalents	(43,753)	1,401	291	(3)	(4)		(42,068)
Cash and equivalents, beginning of year	70,981	2,006	474	98	19		73,578
Cash and equivalents, end of year	$ 27,228	3,407	765	95	15		$ 31,510

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Three months ended March 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and elimina-tions	HECO Consolidated
Cash flows from operating activities							
Net income (loss)	$ 14,402	1,546	2,657	(7)	(7)	(3,960)	$ 14,631
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(3,985)					3,960	(25)
Common stock dividends received from subsidiaries	1,742					(1,717)	25
Depreciation of property, plant and equipment	20,797	8,251	7,376				36,424
Other amortization	694	209	1,303				2,206
Deferred income taxes	(989)	672	(973)				(1,290)
Tax credits, net	1,788	744	(18)				2,514
Allowance for equity funds used during construction	(2,702)	(742)	(161)				(3,605)
Changes in assets and liabilities:							
Decrease in accounts receivable	50,031	10,910	10,709			1,481	73,131
Decrease in accrued unbilled revenues	20,958	3,470	2,946				27,374
Decrease in fuel oil stock	11,476	1,012	2,540				15,028
Increase in materials and supplies	(888)	(262)	(127)				(1,277)
Decrease (increase) in regulatory assets	(3,292)	108	(1,071)				(4,255)
Decrease in accounts payable	(9,968)	(5,432)	(448)				(15,848)
Changes in prepaid and accrued income and utility revenue taxes	(34,394)	(9,605)	(5,562)				(49,561)
Changes in other assets and liabilities	9,256	(1,874)	(121)	(11)	2	(1,481)	5,771
Net cash provided by (used in) operating activities	74,926	9,007	19,050	(18)	(5)	(1,717)	101,243
Cash flows from investing activities							
Capital expenditures	(57,235)	(17,595)	(5,485)				(80,315)
Contributions in aid of construction	1,455	504	403				2,362
Advances from (to) affiliates	(4,550)		(12,500)			17,050	
Net cash used in investing activities	(60,330)	(17,091)	(17,582)			17,050	(77,953)
Cash flows from financing activities							
Common stock dividends	(10,536)		(1,717)			1,717	(10,536)
Preferred stock dividends of HECO and subsidiaries	(270)	(134)	(95)				(499)
Proceeds from issuance of long-term debt		3,148					3,148
	289	4,550				(17,050)	(12,211)

Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less									
Decrease in cash overdraft		(5,865)							(5,865)
Other		(1)							(1)
Net cash provided by (used in) financing activities		(16,383)	7,564	(1,812)			(15,333)		(25,964)
Net decrease in cash and equivalents		(1,787)	(520)	(344)	(18)	(5)			(2,674)
Cash and equivalents, beginning of period		2,264	3,148	1,349	123	17			6,901
Cash and equivalents, end of period	$	477	2,628	1,005	105	12		$	4,227

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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) consolidated financial statements of HEI and HECO and accompanying notes.

HEI Consolidated

RESULTS OF OPERATIONS

(in thousands, except per share amounts)	Three months ended March 31 2010	2009	% change	Primary reason(s) for significant change*
Revenues	$ 619,040	$ 543,797	14	Increase for the electric utility segment, partly offset by a decrease for the bank segment
Operating income	60,707	44,658	36	Increase for the electric utility and the bank segments
Net income for common stock	27,126	20,395	33	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	$ 0.29	$ 0.23	26	Higher net income, partly offset by higher weighted average shares outstanding
Weighted-average number of common shares outstanding	92,572	90,604	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 first quarters of 2010 and 2009 were 36% and 35%, respectively.

Dividends. The payout ratios for 2009 and the first quarter of 2010 were 137% and 106%, 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).

After the deepest recession since the 1930s, the signs of recovery in the U.S. and Japan are positive indicators for the Hawaii economy. The Hawaii economy continues to show signs of recovery. State economists are predicting the pace of the recovery to be a gradual process over the next several years, constrained by U.S. consumer spending and the uncertainty over State and local governments budgets to fund existing programs and positions.

Two of Hawaii s major economic engines, the visitor and construction industries, continue to struggle. However, visitor arrival numbers edged up slightly over the course of 2009 and momentum from the strong fourth quarter continued through March 2010. While the construction industry contracted sharply in 2009, the pace of losses in jobs and new construction authorizations had slowed by year end. The performance of these industries will be critical to Hawaii s economic recovery.

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Visitor arrivals were up 4.1% for the first quarter of 2010 as compared to the same period in 2009. Arrivals in 2010 are expected to be up from 2009 levels by approximately 2.0% year over year, which follows a 4.5% decrease from 2009 over 2008 and 10.6% decrease from 2008 over 2007. Visitor expenditures are expected to be up 2.3% over 2009 following an 11.6% decrease from 2009 over 2008 and 11.0% decrease from 2008 over 2007.

The global credit crisis and recession have impacted the Hawaii construction industry. Commercial and resort building are hampered by financing constraints. However, it is anticipated that government projects will begin to contribute to growth in construction activity this year as the effects of the Federal and State stimulus projects are finally felt. Private building permits are also expected to show modest gains beginning this year.

Conditions in the home resale market appear to be moving towards a recovery. March 2010 marked the third month in a row of an increase compared to the same months in 2009 over the number of closed sales, median sales price, and a decrease of days on the market as well as a decrease in total active listings available at month end. However, analysts are questioning whether the improvements will continue after federal tax credits for home purchases expire at the end of April 2010.

Hawaii s seasonally-adjusted unemployment at the end of March 2010 remained at 6.9% for a third consecutive month. Although unemployment in Hawaii remains below the national average of 9.7%, it remains slightly above the average annual rate of 6.8% for 2009 and is much higher than the average annual rate of 4% for 2008. The Hawaii unemployment rate is expected to remain at 6.9% in 2010. There were extensive job losses in 2009 with the visitor and construction industry taking the largest hits. Although the economy shows signs of recovery, the job market is likely to be the last component of the economy to respond with the private sector leading the way in job creation. Additional public sector job losses are likely. The non-farm job count is expected to show a 0.8% net loss for 2010.

Hawaii economic growth as measured by the change in real personal income is expected to be marginally lower by (0.1)% in 2010 as compared to 2009 according to UHERO s estimate and flat as projected by DBEDT. However, it should be noted that unemployment compensation is included in real personal income.

On a national level, the Blue Chip economic consensus dated April 5-6, 2010 predicts real gross domestic product (GDP) to increase by 2.9% and 3.0% for the first and second quarters of 2010 compared to the immediately preceding quarter, respectively. The consensus continues to predict the economy will grow this year. The outlook has improved for personal consumption, nonresidential fixed investment, trade and corporate profits. The national unemployment rate is expected to average less in 2010 than 2009, but the forecast for housing starts is still worsening.

The price of a barrel of crude oil continues to rise (closing at $86.15 per barrel on April 30, 2010), with prices increasing following a low of $34.03 per barrel on February 12, 2009.

Interest rates remained low during the first quarter of 2010, including relatively low mortgage rates. 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.

Hawaii s economy depends significantly on conditions in the U.S. and international economies, particularly Japan. Assuming the U.S. and international conditions continue to improve, Hawaii s economy is expected to continue to gradually recover in 2010 with modest growth in 2011.

Emergency Economic Stabilization Act of 2008 and American Economic Recovery and Reinvestment Act of 2009. The Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law on October 3, 2008. The principal parts of the 2008 Act were: (1) a $700 billion financial markets stabilization plan; and (2) $150 billion in tax benefits, which are partially offset by $40 billion in revenue raisers. As part of its energy and conservation related incentives, the 2008 Act allowed public utility property to qualify for the energy credit for periods after February 13, 2008 and extended the credit for solar energy property, fuel cell property and microturbine property through December 31, 2016. In addition, the 2008 Act allowed the credit for combined heat and power (CHP) system property as energy property for periods after October 3, 2008. Further, the 2008 Act extended the renewable production credit through December 31, 2009 for qualified wind and refined coal production facilities and through December 31, 2010 for other sources. The 2008 Act also provided for a 10-year accelerated depreciation period for smart electric meters and smart electric grid equipment for property placed in service after October 3, 2008. Finally, the 2008 Act extended the per-gallon incentives for biodiesel and alternative fuels through December 31, 2009. The tax provisions of the 2008 Act did not have a material effect on the Company s results of operations for 2009. These tax provisions, however, may influence the Company s decisions to invest in the various properties entitled to credits and favorable depreciation. The Company evaluates investments by considering the opportunities the 2008 Act presents. For example, in 2009, MECO made investments in CHP equipment for which tax credits of $0.5 million were earned and will be amortized into income over 20 years.

The American Economic Recovery and Reinvestment Act of 2009 (the 2009 Act) was signed into law on February 17, 2009 at a total cost of $787 billion. The 2009 Act, which was intended to provide a stimulus to the U.S. economy in the midst of the global financial crisis, is comprised of tax relief, spending on infrastructure, health care and alternative energy and aid to states and local governments. The 2009 Act includes more than $300 billion in tax relief, which is focused primarily on low- and middle-income taxpayers and small businesses. The energy provisions set in motion President Obama s campaign promises to implement a green economic recovery.

The extension through 2009 of bonus depreciation, originally provided for in the 2008 Act, has had the most direct and immediate impact on the Company. The additional tax depreciation deduction of approximately $68 million increased deferred income taxes by about $26 million in 2009 and provided positive cash flow. The energy related provisions of the 2009 Act may impact utility operations indirectly. Some of the energy incentives were as follows: (1) a 30% tax credit of up to $1,500 for the purchase of highly efficient residential air conditioners, heat pumps or furnaces, (2) $0.3 billion in rebates for purchases of efficient appliances, (3) $20 billion for green jobs to make wind turbines and solar panels and to improve energy efficiency in schools and federal buildings, (4) $6 billion in loan guarantees for renewable energy projects, (5) $5 billion to help low-income homeowners make energy improvements, (6) $11 billion to modernize and expand the U.S. electric power grid, (7) $2 billion for research into batteries for future electric cars and (8) the extension of existing energy incentives and the addition of a few new ones. Finally, the 2009 Act temporarily eliminated the alternative minimum tax preference item for private activity bond interest for bonds (such as special purpose revenue bonds issued by HECO and its subsidiaries) issued in 2009 and 2010, including the $150 million of special purpose revenue bonds issued for the benefit of HECO and HELCO on July 30, 2009.

The Company will continue to analyze the 2009 Act for its impacts on results of operations, financial condition and liquidity and for the opportunities it presents.

Health care and other tax legislation. The Hiring Incentives to Restore Employment Act (HIRE Act), was signed into law on March 18, 2010 at a total cost of $17.6 billion. The HIRE Act provides incentives for hiring and retaining workers by exempting the employer share of social security tax on wages paid to qualified individuals beginning after the date of enactment and ending on December 31, 2010 and by creating a tax credit for retaining these individuals for 52 consecutive weeks. The HIRE Act also expands on the tax credit bond provisions of the 2009 Act by providing a direct payment to issuers of qualified tax credit bonds in lieu of the credits. Qualified tax credit bonds include new renewable energy bonds and qualified energy conservation bonds. The HIRE Act s tax provisions for job creation should not have a material effect on the Company s results of operations, although the enhanced bond provisions may indirectly impact utility operations by raising capital in the marketplace for renewable energy projects. The Company will continue to analyze the HIRE Act for its impact on the Company s results of operations, financial condition and liquidity.

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The Patient Protection and Affordable Care Act was signed into law on March 23, 2010 and was immediately amended by the March 30, 2010 enactment of the Health Care and Education Reconciliation Act of 2010 (collectively referred to as the PPACA). The PPACA enacted comprehensive health care reforms by expanding health insurance coverage to Americans without health insurance and changing the health care delivery system at a gross cost of an estimated $0.9 trillion over ten years.

The cost of these reforms is paid through a combination of cuts in Medicare payments to providers and tax increases. The majority of tax increases will come from additional Medicare hospital insurance (MHI) taxes imposed on high-income taxpayers. The PPACA increases the employee portion of the MHI from the current 1.45% to 2.35%, or an additional 0.9% on wages received in excess of a threshold amount of $200,000 for single taxpayers and $250,000 for married taxpayers. In addition, a new 3.8% Medicare tax on investment income of individuals, estates and trusts will be imposed on the lesser of net investment income or modified adjusted gross income in excess of the same threshold amounts. These new taxes will be effective starting in 2013.

Additionally, the PPACA eliminates the employer deduction for Medicare Part D retiree drug subsidy and imposes a 40% excise tax on high-value/Cadillac employer health coverage valued in excess of specified thresholds. Other revenue raisers, not necessarily connected with health care, include the codification of the economic substance doctrine, expanded information reporting requirements and an increase in estimated tax installment payments.

Benefit provisions of the PPACA expand Medicare drug benefits and require changes in employer plans that will result in an increase in covered individuals and services.

The benefits and tax provisions of the PPACA should not have a material effect on the Company s results of operations, financial condition and liquidity. The Company will continue to analyze the cost implications of the PPACA changes to its benefit plans, payroll taxes and its compliance obligations.

Retirement benefits. For the first quarter of 2010, the Company s and HECO and its subsidiaries defined benefit retirement plans assets generated a return, net of investment management fees, of 5.1%. The market value of the defined benefit retirement plans assets of the Company as of March 31, 2010 was $911 million compared to $874 million at December 31, 2009, an increase of approximately $37 million. The market value of the defined benefit retirement plans assets of HECO and its subsidiaries as of March 31, 2010 was $826 million compared to $792 million at December 31, 2009, an increase of approximately $34 million.

Additional guidance on minimum required contribution determinations for 2010 was released in Special Edition September 25, 2009 employee plans news necessitating selection of a different yield curve for 2010 valuations forward from what was used for 2009. The Company and HECO and its subsidiaries estimate that the cash funding for the qualified defined benefit pension plans in 2010 will be about $30 million and $29 million, respectively, which should fully satisfy the minimum required contribution, including requirements of the utilities pension tracking mechanisms and the plans funding policy.

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. Funding relief for 2010 may be considered by Congress and any action by Congress may affect the amount to be contributed to the plans.

Commitments and contingencies. See Note 7 of HEI s Notes to Consolidated Financial Statements.

Recent accounting pronouncements and interpretations. See Note 9 of HEI s Notes to Consolidated Financial Statements.

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Other segment.

(in thousands)	Three months ended March 31 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 15	$ (32)	NM	
Operating loss	(3,673)	(3,532)	NM	Higher legal expenses
Net loss	(4,662)	(4,619)	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:

(dollars in millions)	March 31, 2010		December 31, 2009	
Short-term borrowings other than bank	$ 60	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	1,453	50	1,442	50
	$ 2,912	100%	$ 2,883	100%

As of May 1, 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 negative.

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 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.

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S&P designates business risk profiles as excellent, strong, satisfactory, fair, weak or vulnerable.

S&P designates financial risk profiles as minimal, modest, intermediate, significant, aggressive or highly leveraged. The Issuer Ranking published by S&P on May 6, 2010 lists HEI s business risk profile as strong and financial risk profile as significant.

On July 20, 2009, Moody s changed HEI s rating outlook to negative from stable and affirmed HEI s long-term and short-term (commercial paper) ratings. Subsequently on August 3, 2009, Moody s issued a credit opinion on HEI. Moody s indicated that HEI s negative rating outlook reflects the impact of a weakened economy that is affecting electric demand and electric sales resulting in weaker financial performance, which may be influencing the outcome of state regulatory decisions, the high dividend payout ratio, the existence of a negative rating outlook at ASB and the concentration risk that exists at HEI from the very high dependence on the Hawaiian economy. Moody s stated that [t]he rating could be downgraded should weaker than expected economic growth and regulatory support emerge at HECO which ultimately causes earnings and sustainable cash flows to suffer over an extended period. Consequently, if Moody s expectations regarding the future sustainable levels of the Company s consolidated financial ratios were to shift such that expectations for Funds From Operations (FFO) (defined as net cash flow from operations less net changes in working capital items) to Adjusted Debt were to fall below 16% (15% last twelve months as of March 31, 2009-latest reported by Moody s) or expectations for FFO to Adjusted Interest were less than 3.5x (3.3x last twelve months as of March 31, 2009-latest reported by Moody s) on a sustained basis, the rating could be lowered.

See the electric utilities and bank s respective Liquidity and capital resources sections below for the ratings of HECO and ASB.

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

(in millions)	Three months ended March 31, 2010 Average balance	Balance March 31, 2010	Balance December 31, 2009
Short-term borrowings (1)			
HEI commercial paper	$ 40	$ 47	$ 42
HEI line of credit draws			
	$ 40	$ 47	$ 42
Line of credit facility (expiring March 31, 2011) (1)		$ 100	$ 100
Undrawn capacity under HEI s line of credit facility (2)		100	100

(1) This table does not include HECO s separate commercial paper issuances and line of credit facilities and draws. At May 1, 2010, HEI s outstanding commercial paper balance was $46 million.

(2) On May 7, 2010, HEI entered into a revolving unsecured credit agreement establishing a line of credit facility of $125 million and the line of credit facility expiring March 31, 2011 was terminated when the new line of credit became effective. At May 7, 2010, HEI s credit facility expiring May 7, 2013 was undrawn. See Note 11 in HEI s Notes to Consolidated Financial Statements.

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. In December 2009, after PUC approval was obtained following HEI s December 2008 public offering of 5 million shares of its common stock for net proceeds of approximately $110 million, HEI contributed $93 million of common equity to HECO ($62 million in cash and $31 million in forgiveness of intercompany indebtedness). As of March 31, 2010, HEI had no short-term loans to HECO.

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.

Issuances of common stock through the Hawaiian Electric Industries, Inc. Dividend Reinvestment and Stock Purchase Plan (DRIP) and the Hawaiian Electric Industries Retirement Savings Plan (HEIRSP) have been important sources of capital for HEI. From January 1, 2009 through April 15, 2009, HEI raised $14 million of new capital through the issuance of approximately 1.0 million shares for these plans. HEI ceased such issuances of stock through DRIP and HEIRSP effective April 16, 2009 and began satisfying the HEI common stock requirements of DRIP and HEIRSP through open market purchases. Also, upon its inception on May 7, 2009, the ASB 401(k) Plan satisfied its HEI common stock requirements through open market purchases. On September 4, 2009, HEI resumed satisfying the HEI common stock requirements of DRIP, HEIRSP and the ASB 401(k) Plan through issuances of new common stock. HEI raised $18 million of new capital through the issuance of approximately 1.0 million shares to these plans from September 4 to December 31, 2009 and an additional $11 million through the issuance of approximately 0.5 million shares during the first quarter of 2010.

For the first three months of 2010, net cash provided by operating activities of consolidated HEI was $10 million. Net cash used by investing activities for the same period was $114 million, primarily due to net increases in ASB investment securities and HECO s consolidated capital expenditures. Net cash used in financing activities during this period was $58 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 three months of 2010, HECO and ASB paid dividends to HEI of $15 million and $11 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 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 $34 million in 2010 ($33 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.

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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 below), 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.

Limited insurance. In the ordinary course of business, the Company purchases insurance coverages (e.g., property and liability coverages) to protect itself against loss of or damage to its properties and against claims made by third-parties and employees for property damage or personal injuries. However, the protection provided by such insurance is limited in significant respects and, in some instances, the Company has no coverage. For electric utility examples, see Limited insurance in Note 5 of HECO s Notes to Consolidated Financial Statements. Certain of the Company s insurance has substantial deductibles or has limits on the maximum amounts that may be recovered. Insurers also have exclusions or limitations of coverage for claims related to certain perils including, but not limited to, mold and terrorism. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, the Company could incur uninsured losses in amounts that would have a material adverse effect on the Company s results of operations and financial condition.

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.

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

Electric utility

RESULTS OF OPERATIONS

(dollars in thousands, except per barrel amounts)	Three months ended March 31 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 548,111	$ 461,797	19	Higher fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers ($69 million), HECO test year 2009 interim rate increase ($16 million), and higher KWH sales ($12 million), partially offset by lower DSM costs recovered through a surcharge ($8 million)
Expenses Fuel oil	211,752	145,289	46	Higher fuel oil costs and more KWHs generated
Purchased power	116,782	114,484	2	Higher fuel costs, partly offset by less KWHs purchased
Other operation	59,244	62,397	(5)	See Results three months ended March 31, 2010 below
Maintenance	27,053	26,163	3	See Results three months ended March 31, 2010 below
Depreciation	38,642	36,424	6	Additions to plant in service in 2009
Taxes, other than income taxes	51,791	45,735	13	Increase in revenues
Other	238	236	1	
Operating income	42,609	31,069	37	Higher sales and HECO test year 2009 interim rate increase, partly offset by higher expenses
Net income for common stock	18,052	14,132	28	Higher operating income, partly offset by lower AFUDC
Kilowatthour sales (millions)	2,273	2,231	2	Stabilizing economy and warmer weather
Cooling degree days (Oahu)	857	759	13	

Average fuel oil cost per barrel	$	81.95	$	60.02	37

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

See Economic conditions in the HEI Consolidated section above.

Results three months ended March 31, 2010. Operating income for the first quarter of 2010 increased 37% from the same period in 2009 due primarily to higher kilowatthour (KWH) sales ($12 million) and the HECO test year 2009 interim rate increase ($16 million, including $1 million related to additional rate relief implemented on February 20, 2010 related to Campbell Industrial Park combustion turbine No. 1 (CIP CT-1)). For the first quarter of 2010, KWH sales increased 1.9% compared with the same quarter of 2009, primarily due to more normal weather relative to last year s unusually cool temperatures.

Other operation expenses decreased by $3.2 million in the first quarter of 2010 primarily due to $7.6 million lower demand-side management (DSM) expenses (see Demand-side management programs below) that are generally passed on to customers through surcharges, partly offset by $3.6 million higher employee benefit costs. Maintenance expense increased $0.9 million primarily due to higher production maintenance.

Operation and maintenance (O&M) expenses are expected to increase 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 are 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 its May 2010 filing with the PUC, 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. 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. HECO s application also requested approval of capital project costs, but MECO s estimated capital project costs were below the threshold that required separate PUC approval. In March 2010, HECO, HELCO and MECO also issued a request for proposals to seek suppliers of biofuel made from feedstocks produced and processed within the State of Hawaii, with final bids due by June 18, 2010.

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). In October 2008, the PUC approved a PPA between MECO and Lanai Sustainability Research, LLC for the purchase of up to 1.2 MW of electricity from a photovoltaic system owned by Lanai Sustainability Research, LLC, a portion of which was placed in service in December 2008. The full output of the system will be allowed once Lanai Sustainability Research completes installation of a battery energy storage system. In November 2008, the PUC approved a PPA between HELCO and Keahole Solar Power LLC (a wholly-owned subsidiary of Sopogy, Inc.) for the purchase of energy from a 500 kilowatt (kW) concentrated solar power facility, which was brought on line in December 2009. In March 2009, an executed term sheet was filed with the PUC for a PPA between HELCO and Hu Honua Bioenergy, LLC, which intends to refurbish a 21.5 MW biomass plant

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located on the island of Hawaii. In July 2009, HECO executed a PPA with Kahuku Wind Power, LLC, subject to PUC approval, to purchase 30 MW of electricity from a wind turbine generating system. HECO filed an application for approval of the PPA and a PPA amendment with the PUC in August 2009 and February 2010, respectively. In December 2009, HECO and Honua Power, LLC signed a PPA, subject to PUC approval, to purchase approximately 6.6 MW of electricity from a biomass gasification power plant on Oahu. HECO filed an application for approval of the PPA with the PUC in January 2010. In addition to the PPAs above, each of the utilities are in active negotiations with other entities seeking PPAs for renewable energy.

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. HECO requested a ruling from the PUC to confirm that the bifurcation was proper and a hearing is scheduled for July 8, 2010.

On July 17, 2009, HECO filed an application requesting approval (1) to defer the costs of outside services (estimated at $6.3 million) incurred in 2009 and 2010 to conduct the studies and analyses necessary (a) to reliably and effectively integrate large amounts of wind-generated renewable energy potentially located on the islands of Molokai and Lanai to the Oahu electric grid, and (b) to assess the potential routes and permitting requirements for the Oahu transmission lines and facilities necessary to interconnect undersea cables delivering power from the Big Wind Projects to Oahu; and (2) to recover the expenses for these Big Wind Implementation Studies through a surcharge mechanism. On December 11, 2009, the PUC issued a decision and order (D&O) that allows HECO to defer costs for the Big Wind Implementation Studies for later review for prudence and reasonableness. The PUC stated that a decision on a specific amount of costs to be recovered from ratepayers would be deferred until a detailed review is conducted at a later date on the actual incurred costs in a rate case or other proceeding. The PUC deferred a decision as to the specific recovery mechanism or the terms of any recovery mechanism (e.g. amortization period or carrying treatment).

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.

Energy efficiency and DSM programs for commercial and industrial customers and residential customers, including load control programs, have resulted in reducing system peak load and contribute to the achievement of the RPS.

For a description of some of the major provisions of the Energy Agreement most directly affecting HECO and its subsidiaries and their commitments relating to renewable energy and energy efficiency, see Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements.

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) IPPs and customer self-generation, with or without cogeneration.

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In October 2003, the PUC opened investigative proceedings on two specific issues (competitive bidding and distributed generation(DG)) to move toward a more competitive electric industry environment under cost-based regulation. For a description of some of the regulatory changes that will be pursued as part of the Energy Agreement, see Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements.

Competitive bidding proceeding. The stated purpose of the PUC s competitive bidding proceeding was to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii. 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 determination of whether to use competitive bidding for a future generation resource or a block of generation resources will be made by the PUC during its review of the utility s integrated resource plan (IRP); (3) the framework does not apply to three pending projects, specifically identified offers to sell energy on an as-available basis or to sell firm energy and/or capacity by non-fossil fuel producers and certain other situations identified in the framework; (4) waivers from competitive bidding for certain circumstances will be considered by the PUC; (5) for each project that is subject to competitive bidding, the utility is required to submit a report on the cost of parallel planning upon the PUC s request; (6) the utility is required to consider the effects on competitive bidding of not allowing bidders access to utility-owned or controlled sites, and to present reasons to the PUC for not allowing site access to bidders when the utility has not chosen to offer a site to a third party; (7) 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); (8) the utility may consider its own self-bid proposals in response to generation needs identified in its RFP; (9) the evaluation of the utility s bid should account for the possibility that the capital or running costs actually incurred, and recovered from ratepayers, over the plant s lifetime, will vary from the levels assumed in the utility s bid; and (10) for any resource to which competitive bidding does not apply (due to waiver or exemption), the utility retains its traditional obligation to offer to purchase capacity and energy from a Qualifying Facility (QF) at avoided cost upon reasonable terms and conditions approved by the PUC.

In 2007, the PUC approved the utilities tariffs containing procedures for interconnection and transmission upgrades, a list of qualified candidates for the Independent Observer position for future competitive bidding processes and a Code of Conduct.

In May 2008, the PUC issued a D&O stating that Puna Geothermal Venture s proposal to modify its existing PPA with HELCO to provide an additional 8 MW of firm capacity by expanding its existing facility is exempt from the Competitive Bidding Framework, and negotiations to modify that PPA are currently ongoing.

In September 2008, HECO submitted fully executed term sheets for the following three renewable energy projects on Oahu that were grandfathered from the competitive bidding process: a Honua Power steam turbine generator, a Kahuku Wind Power wind farm, and a Sea Solar Power International ocean thermal energy conversion project. In October 2008, timelines for the completion and execution of the PPAs and the planned in-service dates for these three projects were submitted to the PUC. In May 2009, HECO submitted to the PUC an update to the October 2008 filing on the status of negotiations for the three projects. HECO and Kahuku Wind Power signed a PPA in July 2009. The PPA and an amendment were submitted to the PUC for approval in August 2009 and February 2010, respectively. HECO and Honua Power signed a PPA in December 2009, and the PPA was submitted to the PUC for approval in January 2010. Negotiations to reach a PPA with OTEC International, LLC (formerly known as Sea Solar Power International) are currently ongoing.

In the third and fourth quarters of 2008, the PUC granted requests for waivers from the Competitive Bidding Framework for five projects. The waivers for four of the five projects subsequently expired without reaching agreement on a term sheet. In March 2009, HELCO reached agreement on a term sheet with the developer of the fifth and remaining waivered biomass project (Hu Honua Bioenergy, LLC). Since this term sheet agreement would have an effect on the proposed competitive bidding process, HELCO retained an independent engineering consultant to evaluate the suitability of the current generation system conditions for issuing an RFP

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for acquiring additional renewable resources. In June 2009, the independent engineer recommended that HELCO not proceed with an RFP at this time and instead conduct further analyses to determine what resource attributes would be most beneficial to the HELCO system and then assess how best to acquire those resources. Those analyses are currently being performed by HELCO.

In September 2009, HECO filed a request for an exemption or waiver from the competitive bidding framework for the City and County of Honolulu s proposed HPOWER expansion project, which involves a modification of an existing PPA with the City. In December 2009, the PUC declared the project exempt from the competitive bidding framework and PPA amendment negotiations are in progress.

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

In January 2006, the PUC issued its 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). The utilities filed their proposed modifications to existing DG interconnection tariffs and their proposed unbundled standby rates for PUC approval in the third quarter of 2006. The Consumer Advocate stated that it did not object to implementation of the interconnection and standby rate tariffs at that time, but reserved the right to review the reasonableness of both tariffs in rate proceedings for each of the utilities. 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 IRP framework). The PUC also affirmed that the electric utility has the responsibility to demonstrate that it meets all applicable criteria included in the D&O in its application for PUC approval to proceed with a specific DG project.

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. In June 2009, the PUC approved the agreement for the DSG facility at the Honolulu International Airport. The PUC also approved HECO s request to waive the project from the Competitive Bidding Framework and HECO s commitment of funds. However, the PUC denied HECO s proposed accounting and rate-making treatment for $0.4 million of capital and overhaul reimbursement payments by HECO to the Department of Transportation under the terms of the agreement. HECO and the Department of Transportation amended the agreement to provide HECO with the ability to seek cost recovery for these expenses in accordance with the PUC order. The amendment was approved by the PUC in March 2010. HECO will seek cost recovery of overhaul reimbursement payments in the next applicable general rate case proceeding.

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

In February 2008, MECO received PUC approval of an 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 new proceeding to investigate the utilities proposed DG interconnection tariff modifications and standby rate tariffs. In March 2008, the parties to the proceeding filed a settlement agreement with the PUC proposing that a standby service tariff agreed to by the parties should be approved. The interconnection tariffs, with modifications made in response to the PUC s information requests, were approved in April 2008. In May 2008, the PUC approved the settlement agreement on the standby service tariff.

In September 2008, the PUC requested that the utilities address various inconsistencies in the interconnection tariff sheets. In the fourth quarter of 2008, the utilities filed revised interconnection tariff sheets and the PUC issued an order approving the revised interconnection tariff sheets and closing the DG tariff proceeding.

As required in the Energy Agreement, the utilities conducted a review of the modified DG interconnection tariffs to evaluate whether the tariffs are effective in supporting non-utility DG and distributed energy storage by improving the process and procedure for interconnection. HECO filed its evaluation report with the PUC in June 2009, concluding that the process has been working efficiently.

On January 7, 2010, a request to modify the DG interconnection tariff was filed by the utilities. Among other modifications, the utilities are seeking to relax requirements for conducting detailed interconnection studies, and are proposing modifications to some technical requirements to accommodate the significant increase in distributed renewable energy generating unit installations that is anticipated as a result of initiatives such as the feed-in tariff. On January 27, 2010, the PUC suspended the request and opened a separate proceeding to examine the proposed modifications.

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 (CEIS) 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 or its amount 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.

As of May 1, 2010, the ROACE found by the PUC to be reasonable in the most recent final rate decision for each utility was 10.7% for HECO (D&O issued on May 1, 2008, based on a 2005 test year), 11.5% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). The ROACEs used by the PUC in the interim rate increases in HECO, HELCO and MECO rate cases based on 2009, 2006 and 2007 test years issued in August 2009, April 2007 and December 2007 were 10.5%, 10.7% and 10.7%, respectively.

For the 12 months ended March 31, 2010, the actual ROACEs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 7.37%, 8.06% and 4.08%, respectively. HECO s actual ROACE was 313 basis points lower than its interim D&O ROACE primarily due to lower KWH sales than the sales used to determine the interim rates and increased O&M expenses, both of which are expected to continue through 2010. HELCO and MECO s actual ROACEs were 264 and 662 basis points, respectively, lower than their interim D&O ROACEs primarily due to increased O&M expenses and lower KWH sales than the sales used to determine the interim rates.

As of May 1, 2010, the ROR found by the PUC to be reasonable in the most recent final rate decision for each utility was 8.66% for HECO, 9.14% for HELCO and 8.83% for MECO (D&Os noted above). The RORs used by the PUC for purposes of the interim D&Os in the HECO, HELCO and MECO rate cases based on 2009, 2006 and 2007 test years were 8.45%, 8.33% and 8.67%, respectively. For the 12 months ended March 31, 2009, the actual RORs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 6.55%, 7.01% and 4.65%, respectively.

HECO, in 2009, and HELCO and MECO, in 2007, received interim D&Os, which included the reclassification to a regulatory asset of the charge for retirement benefits that would otherwise be recorded in accumulated other comprehensive income (AOCI).

For a description of some of the 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.

2007 test year rate case. On December 22, 2006, HECO filed a request for a general rate increase of $99.6 million, or 7.1% over the electric rates then in effect, based on a 2007 test year, an 11.25% ROACE and an 8.92% ROR on a $1.214 billion average rate base. This rate case excluded DSM surcharge revenues and associated incremental DSM costs because certain DSM issues, including cost recovery, were being addressed in another proceeding.

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

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

HECO s application requested a return on HECO s pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of deferred taxes) in rate base. In a separate proceeding brought in 2005, the electric utilities had earlier requested PUC approval to record as a regulatory asset for financial reporting purposes the amounts that would otherwise be charged to AOCI in stockholders equity under a newaccounting standard at the time, but that request was denied by the PUC in January 2007. HECO thus proposed in the 2007 test year rate case to restore to book equity for rate-making purposes the amounts charged to AOCI as a result of adopting that new accounting standard. The authorized ROACE found to be fair in a rate case is applied to the equity balance in determining the utility s weighted cost of capital, which is the rate of return applied to the rate base in determining the utility s revenue requirements. HECO s position was that, if the reduction in equity balance resulting from the AOCI charges is not restored for rate-making purposes, a higher ROACE will be required.

In March 2007, a public hearing on the rate case was held. In April 2007, the PUC granted the DOD s motion to intervene.

In a June 2007 update to its direct testimonies, HECO proposed pension and OPEB tracking mechanisms, similar to the mechanisms that were agreed to by HELCO and the Consumer Advocate and approved on an interim basis by the PUC in the HELCO 2006 test year rate case (discussed below). A pension funding study (required by the PUC in the AOCI proceeding) was filed in the HECO rate case in May 2007. The conclusions in the study were consistent with the funding practice proposed with the pension tracking mechanism. For a discussion of this mechanism and related pension issues (see Note 4 of HECO s Notes to Consolidated Financial Statements).

On September 6, 2007, HECO, the Consumer Advocate and the DOD (the parties) executed and filed an agreement on most of the issues in HECO s 2007 test year rate case and HECO submitted a statement of probable entitlement with the PUC. The agreement was subject to approval by the PUC.

The amount of the revenue increase based on the stipulated agreement was $70 million annually, or a 4.96% increase over current effective rates at the time of the stipulation. The settlement agreement included, as a negotiated compromise of the parties respective positions, an ROACE of 10.7% (and an 8.62% ROR and a $1.158 billion average rate base) to determine revenue requirements in the proceeding. In the settlement agreement, the parties agreed that the final rates set in HECO s 2005 test year rate case may impact revenues at current effective rates and at present rates, and indicated that the amount of the stipulated interim rate increase in this case would be adjusted to take into account any such changes. For purposes of the settlement, the parties agreed to a pension tracking mechanism that does not include amortization of HECO s pension asset (comprised of accumulated contributions to its pension plan in excess of net periodic pension cost and amounting to $68 million at December 31, 2006) as part of the pension tracking mechanism in the proceeding. (This had the effect of deferring the issue of whether the pension asset should be amortized for rate making purposes to HECO s next rate case.)

In accordance with Act 162, the PUC, by an order issued August 24, 2007, had added as an issue to be addressed in the rate case whether HECO s ECAC complies with the requirements of Act 162. In the settlement agreement, the parties agreed that the ECAC should continue in its present form for purposes of an interim rate increase and stated that they were continuing discussions with respect to the final design of the ECAC to be proposed for approval in the final D&O. The parties agreed to file proposed findings of fact and conclusions of law on all issues in this proceeding, including the ECAC. The parties agreed that their resolution of the ECAC issue would not affect their agreement regarding revenue requirements in the proceeding.

On October 22, 2007, the PUC issued, and HECO implemented, an interim D&O granting HECO an increase of $70 million in annual revenues over rates effective at the time of the interim D&O, subject to refund with interest. The interim increase was based on the settlement agreement described above and did not include in rate base the HECO pension asset. The interim D&O also approved, on an interim basis, the adoption of the pension tracking mechanism and a tracking mechanism for OPEB. See Interim increases in Note 5 and Note 4, Retirement benefits, of HECO s Notes to Consolidated Financial Statements.

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On May 1, 2008, the PUC issued the final D&O for HECO s 2005 test year rate case, which was consistent with the stipulated revised results of operations filed by the parties on March 28, 2008. Consistent with the previous settlement agreement with the parties in this case, HECO filed a motion with the PUC in May 2008 to adjust the amount of the annual interim increase in this proceeding from $70 million to $77.9 million to take into account the changes in current effective rates as a result of the final decision in the 2005 test year rate case, and to have the change be effective at the same time the tariff sheets reflecting the final decision in the 2005 rate case become effective. In June 2008, the PUC approved HECO s motion. On September 30, 2008, HECO filed a correction with the PUC to adjust the amount of the annual interim increase for the 2007 test year rate case from $77.9 million to $77.5 million and filed tariff sheets to be effective October 1 through 31, 2008 to refund $0.1 million over-collected from June 20 to September 30, 2008.

On December 30, 2008, HECO and the Consumer Advocate filed a joint set of proposed findings of fact and conclusions of law and HECO requested that the PUC approve the final rate increase of $77.5 million.

Management cannot predict the timing, or the ultimate outcome, of a final D&O in HECO s 2007 test year rate case.

2009 test year rate case. On July 3, 2008, HECO filed a request for a general rate increase of $97 million or 5.2% over the electric rates then in effect (i.e., over rates that included the interim rate increase discussed above granted by the PUC in HECO s 2007 test year rate case), based on a 2009 test year, an 8.81% ROR, an 11.25% ROACE, and a $1.408 billion rate base. HECO s application requested an interim increase of $73 million on or before the statutory deadline for interim rate relief and a step increase of $24 million based on the return on the annualized net investment of the new CIP CT-1 and recovery of associated expenses to be effective at the in-service date of the new unit.

The requested rate increase was based on anticipated plant additions estimated at the time of filing of $375 million in 2008 and 2009 (including the new CIP CT-1 and related transmission line) to maintain and improve system reliability, higher operation and maintenance costs required for HECO s electrical system, and higher depreciation expenses since the last rate case. To the extent actual project costs are higher than the estimate included in the requested rate increase (e.g., higher costs for the CIP CT-1 and transmission line), HECO plans to seek recovery in a future proceeding. As in its 2007 test year rate case, HECO requested continuation of its ECAC in its present form. The request excluded incremental DSM costs from the test year revenue requirement due to the transition of HECO s DSM programs to a third-party program administrator in 2009 as ordered by the PUC.

In August 2008, the PUC granted the DOD s motion to intervene in the rate case proceeding. In September 2008, the PUC held a public hearing on HECO s rate increase application.

In the Energy Agreement, the parties agreed to seek approval from the PUC to implement in the interim D&O in the 2009 HECO rate case a decoupling mechanism (see Decoupling proceeding below). HECO filed updates to its 2009 test year rate case in November and December 2008, which updates proposed to establish a revenue balancing account (RBA) for a decoupling mechanism and a purchased power adjustment clause. As discussed below, the PUC in its interim D&O did not approve the proposal to establish an RBA to be effective as of the date of the interim D&O, pending the outcome of the decoupling proceeding. The PUC asked for more information on the purchased power adjustment clause, and HECO provided additional support for the reasonableness of the surcharge in the supplemental testimonies filed on July 20, 2009.

In March 2009, HECO agreed to remove certain costs and expenses from the rate case, including unamortized system development costs related to the replacement of its customer information system due to a delay in transitioning to the new system. See Note 5 of HECO s Notes to Consolidated Financial Statements.

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In April 2009, the Consumer Advocate and the DOD filed their direct testimonies in this proceeding. The Consumer Advocate recommended a revenue increase of $62.7 million based on its proposed ROR of 7.86%, an ROACE ranging between 9.5% and 10.5% and a proposed average rate base of $1.259 billion. The Consumer Advocate recommended an average rate base treatment for the CIP CT-1, rather than accept the Company s proposal for a step increase based on the annualized net cost of the CIP CT-1 which would go into effect on the in-service date of the new unit. In its recommendations, the Consumer Advocate also removed the costs and expenses identified by HECO in March 2009 relating to the replacement of HECO s customer information system. The DOD recommended a revenue increase of $45.1 million based on its proposed ROR of 7.85%, an ROACE of 9.50% and a proposed average rate base of $1.309 billion. The DOD also recommended an average rate base treatment for the CIP CT-1 and the removal of the costs and expenses identified by HECO in March 2009 relating to the replacement of HECO s customer information system.

On May 15, 2009, HECO, the Consumer Advocate and the DOD (the parties) executed and filed an agreement (the Settlement Agreement) on most of the issues in HECO s 2009 test year rate case proceeding. The Settlement Agreement included an interim increase amounting to $79.8 million annually, or a 6.2% increase. The Settlement Agreement represented a negotiated compromise of the parties respective positions and was approximately 18% lower than HECO s original request for a $97 million increase in revenues. For purposes of the interim decision only, the parties agreed upon an ROACE of 10.50%. The Settlement Agreement reflected the average rate base treatment for the CIP CT-1 rather than HECO s proposal for a step increase based on the annualized net cost of CIP CT-1. As part of the settlement, the parties also agreed that the PUC should allow HECO to establish an RBA, which would remove the linkage between electric revenues and KWH sales, to be effective on the date of the interim D&O. If approved, the RBA would provide a mechanism to adjust revenues (increases/decreases) subsequent to the interim D&O for the differences (shortages/overages) between the actual revenues and the revenues determined in the interim D&O.

The remaining issues among the parties impacting the amount of the increase for the proceeding related to the appropriate test year expense amount for informational advertising, and the appropriate ROACE for the test year. HECO s position is that its test year estimate for informational advertising and an ROACE of 11%, assuming the approval of the parties joint decoupling proposal, is reasonable.

On May 19, 2009, based on the understandings reached in the Settlement Agreement, HECO submitted its statement of probable entitlement, requesting an interim increase of $79.8 million, based on an 8.45% return on average rate base of $1.253 billion.

On July 2, 2009, the PUC issued an interim D&O in this proceeding. The interim D&O approved a rate increase for interim purposes, but directed that adjustments be made to reduce the increase reflected in HECO s statement of probable entitlement for several items, including certain labor expenses, and the costs related to CIP CT-1 ($12.7 million of revenue requirements). Part of the labor expense reduction related to new positions established to carry out initiatives included in the HCEI because those initiatives are still the subject of pending PUC proceedings and have not yet been approved. The PUC removed the costs related to CIP CT-1 from rate base, indicating that the record did not yet demonstrate that the CIP CT-1 unit would be in service by the end of the 2009 test year. The PUC deferred decision on the proposal to establish an RBA, pending the outcome of the decoupling proceeding.

Based on the adjustments, HECO calculated the interim increase amount at $61.1 million annually or a 4.7% increase (compared to $79.8 million, or a 6.2% increase, agreed to by the parties under the Settlement Agreement) and submitted the information to the PUC on July 8, 2009. The interim increase amount is based on an ROACE of 10.50% agreed to by the parties for purposes of the interim decision only, and an 8.45% ROR on a rate base of $1.169 billion (compared to the average rate base of $1.253 billion agreed to by the parties in the Settlement Agreement).

On July 15, 2009, in responding to HECO s calculations, the Consumer Advocate stated that HECO s proposed adjustments were conservatively prepared, that HECO s revised schedules were in general compliance with the PUC s interim D&O, and that it did not object to HECO s filing.

The Consumer Advocate also identified HCEI-related costs of $1.5 million that were included in the Settlement Agreement and HECO s statement of probable entitlement that it believed could be subject to interpretation as to whether they should be included in the interim rate relief under the D&O. HECO filed a response providing an explanation supporting the inclusion of these costs in its original interim increase calculations. The DOD did not file any comments on HECO s interim increase calculations. The interim decision was implemented on August 3, 2009.

In the interim D&O, the PUC indicated that the parties are allowed to provide additional testimonies regarding the items excluded from the statement of probable entitlement and requested additional testimonies on certain issues by July 20, 2009. HECO, the Consumer Advocate and the DOD provided testimonies on those issues on July 20, 2009. In hearings that began on October 26, 2009, HECO requested approval of an ROACE of 10.75%, assuming the approval of a joint decoupling proposal (see Decoupling proceeding below).

In November 2009, HECO filed a motion with the PUC requesting a second interim increase of $12.7 million to recover CIP CT-1 costs, by allowing HECO to include the costs for the test year in rate base or by allowing HECO to continue to accrue allowance for funds used during construction (AFUDC) on the costs.

On December 22, 2009, HECO filed an application requesting PUC approval of a two-year contract with Renewable Energy Group Marketing and Logistics, LLC (REG) to supply biodiesel for use primarily in CIP CT-1, and to include the contract costs in HECO s ECAC. A decision is pending. On January 5, 2010, HECO notified the PUC that testing of CIP CT-1 had confirmed that it can operate on biofuels and that it had submitted the emissions data derived from that testing to the Department of Health of the State of Hawaii (DOH) in seeking necessary permit modifications.

In January 2010, HECO, the Consumer Advocate and the DOD filed their briefs for this rate case. In its reply brief, HECO indicated its final position was to request a revenue increase for the 2009 test year of $80.2 million over revenues at current rates, based on an ROACE of 10.75% and an ROR of 8.58% on an average rate base of $1.251 billion, which assumes approval of the utilities decoupling proposal and other rate rider mechanisms. Without these mechanisms, revenue requirements would be based on an ROACE of 11% and an ROR of 8.72%.

On February 19, 2010, the PUC issued a second interim D&O in this proceeding granting HECO an additional increase of $12.7 million in annual revenues to recover costs associated with CIP CT-1 and related transmission facilities. HECO implemented this second interim increase effective February 20, 2010. The increase was based on an ROACE of 10.50% and an ROR of 8.45%, both of which were used for the first interim increase.

In the second interim D&O, the PUC stated that, pending receipt of an operational supply of biodiesel, it will allow HECO to operate CIP CT-1 as a diesel peaking unit. It required HECO to provide a report to the PUC quarterly detailing its progress in obtaining the necessary air permit modification (which has since been obtained), and in acquiring an operational supply of biodiesel, until these items are secured. If the PUC is not satisfied with the biofuel progress when the final D&O in this proceeding is issued, the PUC reserves the right to take further action, including removing the CT-1 costs from rate base and ordering any appropriate refunds to ratepayers.

The two interim increases granted totaled $73.8 million, or a 5.7% increase, with amounts collected under the interim orders subject to refund, with interest, to the extent they exceed the amount approved in the final D&O.

On April 12, 2010, the Consumer Advocate filed a Statement of Position in the REG two-year biodiesel contract proceeding. The Consumer Advocate stated that it does not object to the PUC s approval of HECO s supply contract with REG and that the provisions of the supply contract appear to be fair and reasonable and in the best interest of HECO s ratepayers.

Management cannot predict the timing, or the ultimate outcome of, a final D&O in HECO s 2009 test year rate case or in the proceeding for approval of the fuel contract with REG.

2011 test year rate case. On May 6, 2010, HECO filed a Notice of Intent to file an application for a general rate increase on or after July 7, 2010, using a 2011 test year.

HELCO.

2006 test year rate case. In May 2006, HELCO filed a request for a general rate increase of $29.9 million, or 9.24% over the electric rates then in effect, based on a 2006 test year, an 8.65% ROR, an 11.25% ROACE and a $369 million average rate base. HELCO s application included a proposed new tiered rate structure, which would enable most residential users to see smaller increases in the range of 3% to 8%. The tiered rate structure was

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designed to minimize the increase for residential customers using less electricity and is expected to encourage customers to take advantage of solar water heating programs and other energy management options. In addition, HELCO s application proposed new time-of-use service rates for residential and commercial customers. The proposed rate increase would pay for improvements made to increase reliability, including transmission and distribution line improvements and the two generating units at the Keahole power plant (CT-4 and CT-5), and increased O&M expenses. The application requested the continuation of HELCO s ECAC.

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

Keahole Defense Coalition (whose participation in the proceeding is limited) submitted in February 2007 a Position Statement in which it contended that the PUC should exclude from rate base a greater amount of the CT-4 and CT-5 costs than proposed by the Consumer Advocate.

In March 2007, HELCO and the Consumer Advocate reached settlement agreements on all revenue requirement issues in the HELCO 2006 rate case proceeding, which were documented in an April 5, 2007 settlement letter. Under the revenue requirement agreement, HELCO agreed to write off a portion of CT-4 and CT-5 costs, which resulted in an after-tax charge of approximately $7 million in the first quarter of 2007.

On April 4, 2007, the PUC issued an interim D&O, which was implemented by tariff changes made effective on April 5, 2007, granting HELCO an increase of 7.58%, or $24.6 million in annual revenues, over revenues at present rates for a normalized 2006 test year. The interim increase reflects the settlement of the revenue requirement issues reached between HELCO and the Consumer Advocate and is based on an average rate base of $357 million (which reflects the write-off of a portion of CT-4 and CT-5 costs) and an ROR of 8.33% (incorporating an ROACE of 10.7%). In the interim D&O, the PUC also approved on an interim basis the adoption of pension and OPEB tracking mechanisms (see Note 4 of HECO s Notes to Consolidated Financial Statements).

Pursuant to an agreed upon schedule of proceedings, Keahole Defense Coalition filed a response to HELCO s rebuttal testimony on April 28, 2007, to which HELCO responded on May 11, 2007. On May 15, 2007, HELCO and the Consumer Advocate filed a settlement letter that reflected their agreement on the remaining rate design issues in the proceeding. HELCO and the Consumer Advocate filed their opening briefs in support of their settlement on June 4, 2007 and agreed not to file reply briefs. In April 2008, HELCO and the Consumer Advocate filed a supplement providing additional record cites and supporting information relevant to their April 2007 settlement letter. In July 2008, HELCO submitted responses to information requests from the PUC regarding the impacts of passing changes in fuel and purchased energy costs to customers through the ECAC.

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

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 (i.e., over rates that include the $24.6 million interim rate increase discussed above granted in HELCO s 2006 test year rate case), based on a 2010 test year, an 8.73% ROR, a 10.75% ROACE and a $487 million average rate base. The proposed rate increase would cover investments for system upgrade projects, including an 18 MW heat recovery steam generator (ST-7) at Keahole and two major West Hawaii transmission line upgrades, as well as increasing O&M costs for the island s electrical system. 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) between the utilities and the Consumer Advocate, (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 over the electric rates then in effect, based on an ROR of 8.87% and an ROACE of 11.0%.

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HELCO s general rate increase is based on proposed revised depreciation rates for which PUC approval was requested in an application filed on November 9, 2009. If a decision on the depreciation rates change has not been rendered by the time an interim D&O is to be issued in this proceeding, HELCO s application requests that the interim rate relief be based on the existing depreciation rates, and that upon issuance of the D&O on the proposed depreciation rates change, the PUC approve an adjustment (i.e., depreciation step down) that would effectively implement the difference between HELCO s revenue increase based on its existing depreciation rates and the new depreciation rates approved.

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. The proposed rate structure also includes the continuation of HELCO s ECAC. Pursuant to the Energy Agreement, HELCO proposes the establishment of a purchased power adjustment clause to recover non-energy PPA costs to be effective upon issuance of the final D&O. The adoption of pension and OPEB tracking mechanisms is included in the test year estimates that were approved on an interim basis by the PUC in HELCO s 2006 test year interim D&O.

In February 2010, the PUC held public hearings on HELCO s 2010 test year rate case. In May 2010, the PUC approved a stipulated procedural order for the proceeding, which includes evidentiary hearings in 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, or 5.3% over the electric rates then in effect, based on a 2007 test year, an 8.98% ROR, an 11.25% ROACE and a $386 million average rate base. MECO s application included a proposed new tiered rate structure for residential customers to reward customers who practice energy conservation with lower electric rates for lower monthly usage. The proposed rate increase would pay for improvements to increase reliability, including two new generating units added since MECO s last rate case (which was based on a 1999 test year) at its Maalaea Power plant (M19, a 20 MW CT placed in service in 2000, and M18, an 18 MW steam turbine placed in service in October 2006 to complete the installation of a second dual-train combined cycle unit), and transmission and distribution infrastructure improvements. The proposed rate structure also included continuation of MECO s ECAC. The application requested a return on MECO s pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of deferred income taxes) in rate base. The application also proposed to restore book equity (in determining the equity balance for rate-making purposes) for the amounts that were charged against equity (i.e., to AOCI) as a result of recording a pension and other postretirement benefits liability after implementing a new accounting standard at that time.

In an update to its direct testimonies filed in September 2007, MECO proposed a lower increase in annual revenues of $18.3 million, or 5.1%, but its request continued to be based on an 8.98% ROR and an 11.25% ROACE. Also in the update, MECO proposed tracking mechanisms for pension and OPEB, similar to the mechanisms proposed by HECO and HELCO, and approved by the PUC on an interim basis, in their 2007 and 2006 test year rate cases, respectively. In October 2007, the Consumer Advocate filed its direct testimony, which recommended a revenue increase of $8.9 million, based on an ROACE of 10.0% and an ROR of 8.29% on an average rate base of $378 million. $4.75 million of the $9.4 million difference between MECO s and the Consumer Advocate s proposed increase was due to the Consumer Advocate s lower recommended ROR and ROACE.

On December 7, 2007, MECO and the Consumer Advocate (for purposes of this section, the parties) reached a settlement of all the revenue requirement issues in this rate case proceeding. For purposes of the settlement, the parties agreed that MECO s ECAC provided a fair sharing of the risks of fuel cost changes between MECO and its ratepayers and no further changes were required for MECO s ECAC to comply with the requirements of Act 162.

On December 21, 2007, the PUC issued an interim D&O granting MECO an increase of $13.2 million in annual revenues, or a 3.7% increase, subject to refund with interest. The interim increase was based on the settlement agreement, which included as a negotiated compromise of the parties respective positions an increase of $13.2 million in annual revenue, a 10.7% ROACE, an 8.67% ROR and a rate base of $383 million (which included estimated costs of $64.8 million for the generating unit M18, which is $19.4 million higher than the PUC approved amount, but did not include MECO s pension asset, which amounted to $1 million as of December 31, 2007).

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In the interim D&O, the PUC also approved on an interim basis the adoption of pension and OPEB tracking mechanisms (see Note 4 of HECO s Notes to Consolidated Financial Statements).

On July 17, 2009, the parties filed joint proposed findings of fact and conclusions of law.

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

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, an 8.57% ROR, a 10.75% ROACE and a $390 million average rate base. The proposed rate increase would cover investments to improve service reliability, including the replacement and upgrade of the Maalaea generating units (M17 & M19) power plant control systems, installation of a new 150-kW photovoltaic system at MECO s Kahului Baseyard to incorporate solar energy into MECO s facilities, replacement and upgrade of underground lines, new or expanded substations to support past and future 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 between the utilities (HECO, HELCO and MECO) and the Consumer Advocate. If the Joint Decoupling Proposal is not approved, the test year revenue requirements would have to be recalculated according to an ROR of 8.72% and an ROACE of 11%.

MECO s general rate increase is based on proposed revised depreciation rates for which PUC approval was requested in an application filed on September 10, 2009. If a decision on the depreciation rates change has not been rendered by the time an interim D&O is to be issued in the 2010 test-year rate case proceeding, MECO s filing requests that the interim rate relief be based on the existing depreciation rates, and that upon issuance of the D&O on the proposed depreciation rates change, the PUC approve an adjustment (i.e., depreciation step down) that would effectively implement the difference between MECO s revenue increase based on its existing depreciation rates and the new depreciation rates approved.

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. The proposed rate structure also includes the continuation of MECO s ECAC. Pursuant to the Energy Agreement, MECO proposes the establishment of a purchased power adjustment clause to recover non-energy PPA costs to be effective upon issuance of the final D&O. The adoption of pension and OPEB tracking mechanisms is included in the test year estimates that were approved on an interim basis by the PUC in MECO s 2007 test year interim D&O.

In December 2009, the PUC held public hearings on MECO s 2010 test year rate case. On May 5, 2010, the Consumer Advocate filed its direct testimony which recommended a revenue increase of $7.0 million, based on a ROR of 7.86% and a ROACE of 9.50%, and an average rate base of $384 million. The $21.2 million difference between MECO s and the Consumer Advocate s proposed increase is due to the Consumer Advocate s lower recommended ROR and ROACE, higher sales forecast, and other proposed adjustments in test year expenses. Evidentiary hearings are scheduled for July 2010.

Management cannot predict the timing, or the ultimate outcome, of an interim or 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 2009 HECO rate case interim decision, a decoupling mechanism, similar to that in place for several California utilities, which decouples revenue of the utilities 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.

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

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

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 in either pending or new PUC proceedings.

Demand-side management programs.

Energy Efficiency DSM Programs. On February 13, 2007, the PUC issued its D&O in the EE DSM Docket that had been opened by the PUC to bifurcate the EE DSM issues originally raised in the HECO 2005 test year rate case. In the D&O, the PUC required that the administration of all EE DSM programs be turned over to a non-utility, third-party administrator, with the transition to the administrator to be funded through a public benefits fund (PBF) surcharge. See Public benefits fund in Note 5 of HECO s Notes to Consolidated Financial Statements.

In July 2008, the PUC issued an Order to initiate the collection of funds for the PBF Administrator. The PUC executed a PBF Administrator contract with Science Applications International Corporation (SAIC) in March 2009. On July 1, 2009, SAIC began administering the EE DSM programs.

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 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

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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 and HECO is currently negotiating with the vendor selected through a bidding process.

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. HECO s response to the PUC s order and its filing date are dependent on the outcome of discussions with the Consumer Advocate.

Clean energy scenario planning, integrated resource planning, requirements for additional generating capacity and adequacy of supply. The PUC issued an order in 1992 requiring the energy utilities in Hawaii to develop IRPs, which 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 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

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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 distributed generation 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 and named HECO, HELCO, MECO, Kauai Island Utility Cooperative (KIUC) and the Consumer Advocate as parties to the proceeding. Subsequently, twelve others were granted intervenor or participant status in the proceeding. The PUC held panel hearings in February 2010 and briefs are scheduled to be filed in the second quarter of 2010.

The utilities latest IRPs are described below. 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.

HECO s IRP. On September 30, 2008, HECO filed its fourth IRP (IRP-4) covering a 20-year (2009-2028) planning horizon, subject to PUC approval. The IRP-4 preferred plan called for all future generation to be renewable. In addition, it called for conversion of a number of existing HECO-owned generating units to utilize biofuels and for continued aggressive implementation of DSM programs. In addition to CIP CT-1, HECO had plans to pursue the installation of a second 100 MW biofueled CT at the same station in the 2011-2012 timeframe and to submit to the PUC a request for a waiver from the competitive bidding process to install this increment of additional firm capacity. The addition of two simple-cycle CTs would add to the system additional fast starting and ramping capability, which would facilitate integration of as-available generation (such as wind and solar) to the system. HECO also had plans to remove Waiau Unit 3, a 46 MW oil-fired cycling unit, from service after the placing in service of the second CT, and to later determine whether to place the unit in emergency reserve status or to retire the unit.

When the necessary test biofuels are obtained, HECO plans to conduct a test on Kahe Unit 3 to evaluate the use of Low Sulfur Fuel Oil/biofuel blends in existing oil-fired steam units. Other renewable generation is expected to be acquired via three renewable energy projects grandfathered from competitive bidding and from projects that are selected from proposals submitted in response to HECO s 100 MW RFP for Non-Firm Energy (see Competitive bidding proceeding above).

HELCO s IRP. In May 2007, HELCO filed its third IRP (IRP-3). The plan included the installation of a nominal 16 MW steam turbine (ST-7) in 2009 at its Keahole Generating Station (see Major projects in Note 5 of HECO s Notes to Consolidated Financial Statements). The plan also followed through on a commitment to have no new fossil-fired generation installed after ST-7. The plan anticipated increasing customer photovoltaic systems plus a 37 gigawatthours per year renewable energy resource in the 2014 to 2020 timeframe, a firm capacity renewable energy resource in 2022, energy efficiency (continuation of existing DSM programs) and CHP. In November 2007, HELCO and the Consumer Advocate filed a stipulated agreement which recommended that the PUC approve HELCO s IRP-3, in which HELCO agreed to make improvements to the IRP process and to submit evaluation reports. In January 2008, the PUC issued its D&O approving HELCO s IRP-3.

MECO s IRP. In April 2007, MECO filed its third IRP, which proposes multiple solutions to meet future energy needs on the islands of Maui, Lanai and Molokai, including renewable energy resources (such as photovoltaics, additional wind, biomass and waste-to-energy), energy efficiency (continuation of existing and addition of new DSM programs), technology (such as CHP and DG) and competitive bidding for generation or blocks of generation on Maui for 20 MW in each of 2011 and 2013 and 18 MW in 2024 which, under the utility parallel plan, could be located at its Waena site. (These dates were subsequently deferred see discussion of MECO s 2010 Adequacy of Supply (AOS) letter below.) In July 2008, the PUC approved MECO s IRP-3.

HECO s 2009 CIP CT-1 and transmission line. See CIP CT-1 and transmission line in Note 5 of HECO s Notes to Consolidated Financial Statements.

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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 through 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 through 2012 is sufficient to meet the forecasted demands on the islands of Maui, Lanai and Molokai. The letter affirmed the conclusions stated in the September 2009 update which indicated that the estimated need date for the next increment of firm capacity on the island of Maui is 2021 but that if peak demand is higher than forecast then the need date for the next increment of firm generating capacity could be as soon as 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 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.

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Legislation and regulation. Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. See, for example, Hawaii Clean Energy Initiative and Environmental regulation in Note 5 of HECO s Notes to Consolidated Financial Statements and Emergency Economic Stabilization Act of 2008 and American Economic Recovery and Reinvestment Act of 2009 and Health care and other tax legislation above.

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, would increase the price of gasoline and electricity.

Other developments.

Advanced Metering Infrastructure (AMI). On December 1, 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 includes 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 has not approved the application by December 31, 2009, which date has been extended by the parties to June 30, 2010. The parties entered into this extension with respect to the termination right to provide additional time to address certain issues that have arisen with the AMI project, to conduct an extended pilot test of the Sensus AMI system and smart meters and to negotiate amendments to the existing contract with Sensus.

HECO submitted a proposal to the PUC on May 4, 2010, describing an extended pilot test of the Sensus 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. If HECO s request to defer certain costs of the extended pilot testing is approved by the PUC, the extended pilot testing is expected to be completed by the end of 2011.

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

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

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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)	March 31, 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	1,309	54	1,306	55
	$ 2,415	100%	$ 2,398	100%

As of May 1, 2010, the S&P and Moody s ratings of HECO securities were as follows:

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

The above ratings reflect only the view, at the time the ratings are issued, of the applicable rating agency, from whom an explanation of the significance of such ratings may be obtained. Such ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating.

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

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

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 negative.

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 November 2009, S&P further noted that [r]esolution of the negative outlook will also significantly consider regulatory outcomes next year, including whether the company can demonstrate progress in moving toward a more credit-supportive regulatory model that is being contemplated as part of the Clean Energy Initiative. In a bulletin dated February 25, 2010, relating to the revenue decoupling order and HECO s 2009 test year rate case second interim order (February rulings), S&P indicated that the rulings do not affect the ratings on HECO or HEI.

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S&P further stated that the rulings demonstrate progress in managing the full regulatory docket for HECO, but that the ongoing need for timely rate relief remains a factor in the negative outlook assigned to the utility and its parent. S&P also noted that [t]he negative outlook also reflects a weak island economy, the parent s reliance on the utility for distributions given HECO s growing capital program, and deteriorating credit metrics.

S&P designates business risk profiles as excellent, strong, satisfactory, fair, weak or vulnerable. S&P designates financial risk profiles as minimal, modest, intermediate, significant, aggressive or highly leveraged. The Issuer Ranking published by S&P on May 6, 2010 lists business risk profile as strong and financial risk profile as significant.

On July 20, 2009, Moody s changed HECO s rating outlook to negative from stable and affirmed HECO s long-term and short-term (commercial paper) ratings. Subsequently, on August 3, 2009, Moody s issued a credit opinion on HECO. Moody s indicated that (1) the rating affirmation reflects the fact that notwithstanding the issues outlined in the credit opinion, the utilities financial metrics are reasonably positioned in its rating category and (2) HECO s negative rating outlook reflects the impact of a weakened economy that is affecting electric demand and electric sales resulting in weaker financial performance, which may be influencing the outcome of state regulatory decisions, at a time when the company s capital investment program is substantial. Moody s stated that [t]he rating could be downgraded should weaker than expected regulatory support emerge at HECO or if the economy worsens materially more than anticipated causing earnings and sustainable cash flows to suffer. Consequently, if the utilities financial ratios declined on a permanent basis such that Funds From Operations (FFO) (defined as net cash flow from operations less net changes in working capital items) to Adjusted Debt falls below 17% (17% last twelve months as of March 31, 2009-latest reported by Moody s) or FFO to Adjusted Interest declines to less than 3.5x (3.6x last twelve months as of March 31, 2009-latest reported by Moody s) for an extended period, the rating could be lowered. On February 23, 2010, Moody s issued a comment on the recent February rulings as being credit supportive for the ratings but will not result in any change in ratings or ratings outlook at this time. Moody s also noted that both companies credit metrics remain weak for their current rating due in part to the impact that the Hawaiian economy has had on financial results, and the order on decoupling is an important first step in beginning to address the regulatory lag that has historically affected HEI s and HECO s financial results negatively.

Information about HECO s short-term borrowings (other than from MECO), HECO s line of credit facilities and special purpose revenue bonds authorized by the Hawaii legislature for issuance for the benefit of the utilities was as follows for the period and as of the dates indicated:

(in millions)	Three months ended March 31, 2010 Average balance	Balance March 31, 2010	Balance December 31, 2009
Short-term borrowings (1)			
Commercial paper	$ 1	$ 14	$
Line of credit draws			
Borrowings from HEI			
Line of credit facilities			
Undrawn capacity under line of credit facility expiring March 31, 2011 (2)		175	175
Special purpose revenue bonds authorized for issue			
2005 legislative authorization (expiring June 30, 2010)-HELCO		$ 20	$ 20
2007 legislative authorization (expiring June 30, 2012)			
HECO		170	170
HELCO		55	55
MECO		25	25

Total special purpose revenue bonds available for issue	$ 270	$ 270

(1) At May 1, 2010, HECO s outstanding commercial paper balance was $19 million. HECO had no borrowings from HEI.

(2) On May 7, 2010, HECO entered into a revolving unsecured credit agreement establishing a line of credit facility of $175 million and the line of credit facility expiring March 31, 2011 was terminated when the new line of credit became effective. At May 7, 2010, HECO s credit facility expiring on May 6, 2011 was undrawn. See Note 9 in HECO s Notes to Consolidated Financial Statements.

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HECO utilizes short-term debt, typically commercial paper, to support normal operations 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. At March 31, 2010, HECO had nil and $8 million of short-term borrowings from HEI and MECO, respectively, and HELCO had $16 million of short-term borrowings from HECO. HECO had average outstanding balances of commercial paper and credit facility draws for the first quarter of 2010 of $1 million and nil, respectively, and $14 million of commercial paper outstanding at March 31, 2010.

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 S&P s downgrade of HECO s short-term borrowing rating to A-3 from A-2, HECO drew on its $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. 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.

Revenue bonds are issued by the DBF to finance capital improvement projects of HECO and its subsidiaries, but the source of their repayment is the unsecured obligations of HECO and its subsidiaries under loan agreements and notes issued to the DBF, including HECO s guarantees of its subsidiaries obligations. 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. 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 to sell bonds in the future.

Operating activities used $10 million in net cash during the first three months of 2010. Investing activities during the same period used net cash of $30 million for capital expenditures, net of contributions in aid of construction. Financing activities for the same period used net cash of $2 million, primarily due the payment of $16 million of common and preferred dividends partly offset by a $14 million net increase in short-term borrowings.

The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO.

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. 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.

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Bank

RESULTS OF OPERATIONS

(in thousands)	Three months ended March 31 2010	2009	% change	Primary reason(s) for significant change
Revenues	$ 70,914	$ 82,032	(14)	Lower interest income primarily due to lower earning asset balances as a result of the sale of substantially all of the 1-4 family residential loan production in 2009 and the first quarter 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
Operating income	21,771	17,121	27	Lower provision for loan losses, higher noninterest income and lower noninterest expenses partially offset by lower net interest income
Net income	13,736	10,882	26	Higher operating income

See Economic conditions in the HEI Consolidated section above.

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 months ended March 31, 2010 and 2009.

Three months ended March 31 ($ in thousands)	2010 Average Balance	2010 Interest	2010 Average Rate (%)	2009 Average Balance	2009 Interest	2009 Average Rate (%)
Assets:						
Other investments (1)	$ 394,588	$ 183	0.19	$ 107,118	$	
Investment and mortgage-related securities	454,960	3,134	2.75	675,927	7,676	4.54
Loans receivable (2)	3,679,380	49,745	5.43	4,177,039	58,092	5.58
Total interest-earning assets	4,528,928	53,062	4.70	4,960,084	65,768	5.32
Allowance for loan losses	(40,868)			(36,265)		
Non-interest-earning assets	412,987			359,244		
Total assets	$ 4,901,047			$ 5,283,063		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,369,574	1,040	0.18	$ 2,119,976	2,347	0.45
Time certificates	848,526	3,383	1.62	1,326,957	9,218	2.82
Total interest-bearing deposits	3,218,100	4,423	0.56	3,446,933	11,565	1.36

Other borrowings		294,869		1,426	1.94		561,166		3,264	2.33
Total interest-bearing liabilities		3,512,969		5,849	0.67		4,008,099		14,829	1.50
Non-interest bearing liabilities:										
Deposits		796,705					714,499			
Other		92,844					85,360			
Stockholder s equity		498,529					475,105			
Total Liabilities and Stockholder s Equity	$	4,901,047				$	5,283,063			
Net interest income			$	47,213				$	50,939	
Net interest margin (%) (3)					4.18					4.11

(1) Includes federal funds sold, interest bearing deposits and stock in the FHLB of Seattle ($98 million as of March 31, 2010).

(2) Includes loan fees of $1.4 million and $1.9 million for the three months ended March 31, 2010 and 2009, respectively, together with interest accrued prior to suspension of interest accrual on 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:

	March 31, 2010		December 31, 2009	
(dollars in thousands)	**Balance**	**% of total**	**Balance**	**% of total**
Real estate loans:				
Residential 1-4 family	$ 2,263,070	61.8	$ 2,319,738	62.5
Commercial real estate	248,911	6.8	255,458	6.9
Home equity line of credit	340,243	9.3	328,164	8.8
Residential land	89,003	2.4	96,515	2.6
Commercial construction	78,848	2.1	68,107	1.8
Residential construction	10,408	0.3	16,598	0.5
Total real estate loans, net	3,030,483	82.7	3,084,580	83.1
Commercial	546,983	14.9	542,686	14.6
Consumer	86,961	2.4	84,906	2.3
	3,664,427	100.0	3,712,172	100.0
Less: Allowance for loan losses	41,300		41,679	
Total loans, net	$ 3,623,127		$ 3,670,493	

The decrease in the total loan portfolio during the first quarter of 2010 was primarily due to ASB s strategic decision to sell substantially all of the salable residential loans it originated in the quarter ($54 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)	March 31, 2010	December 31, 2009
Real estate loans:		
Residential 1-4 family	$ 40,900	$ 31,686
Commercial real estate	717	344
Home equity line of credit	2,652	2,755
Residential land	22,722	25,162
Commercial construction		
Residential construction		325
	66,991	60,272
Commercial	6,562	4,171
Consumer	595	715
Total nonperforming loans	74,148	65,158
Real estate owned:		
Residential 1-4 family	1,816	1,806
Residential land	2,348	2,153
Total real estate owned loans	4,164	3,959
Total nonperforming assets	$ 78,312	$ 69,117
Nonperforming assets to total loans and REO	2.13%	1.85%

The increase in nonperforming loans was primarily due to an increase in residential first mortgage loans that are 90 days or more past due and 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:

	March 31, 2010		December 31, 2009	
(dollars in thousands)	Balance	% of total	Balance	% of total
Real estate loans:				
Residential 1-4 family	$ 4,803	61.8	$ 5,522	62.5
Commercial real estate	762	6.8	861	6.9
Home equity line of credit	3,885	9.3	4,679	8.8
Residential land	3,868	2.4	4,252	2.6
Commercial construction	3,629	2.1	3,068	1.8
Residential construction	12	0.3	19	0.5
Total real estate loans, net	16,959	82.7	18,401	83.1
Commercial	19,425	14.9	19,498	14.6
Consumer	2,955	2.4	2,590	2.3
	39,339	100.0	40,489	100.0
Unallocated	1,961		1,190	
Total allowance for loan losses	$ 41,300		$ 41,679	

Investment and mortgage-related securities. As of March 31, 2010, the bank s investment portfolio consisted of 52% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), 47% federal agency obligations and 1% municipal bonds. As of December 31, 2009, the bank s investment portfolio consisted of 75% mortgage-related securities issued by FNMA, FHLMC or GNMA, 24% federal agency obligations and 1% municipal bonds.

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

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Deposits and other borrowings. Deposits continue to be the largest source of funds for ASB and are affected by market interest rates, competition and management s responses to these factors. Deposit retention and growth will remain challenges in the current environment due to competition for deposits and the level of short-term interest rates. Advances from the Federal Home Loan Bank (FHLB) of Seattle and securities sold under agreements to repurchase continue to be additional sources of funds. As of March 31, 2010 and 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 March 31, 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 $6 million and $5 million, respectively. See Quantitative and qualitative disclosures about market risk.

Results three months ended March 31, 2010.Net interest income before provision for loan losses for the first quarter of 2010 decreased by $3.7 million, or 7%, 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 4.11% in the first quarter of 2009 to 4.18% in the first 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 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 $452 million as ASB sold substantially all of its salable residential loan production during 2009 and the first quarter of 2010. Average commercial, residential land and construction loan balances decreased by $47 million, $31 million and $20 million, respectively, due to paydowns in the portfolio. The average home equity lines of credit portfolio increased by $52 million. The decrease 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 and paydowns in the portfolio. Average deposit balances decreased by $147 million compared to the first quarter of 2009. The average term certificate balance decreased by $478 million due to the outflow of term certificates throughout 2009 and the first quarter 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. Offsetting the decrease in the term certificate portfolio was growth in the average core deposit balance of $332 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 $266 million primarily due to the payoff of maturing other borrowings.

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During the first quarter of 2010, ASB recorded a provision for loan losses of $5.4 million primarily due to the higher net charge-offs during the quarter for 1-4 family and residential lot loans. Continued financial stress on ASB s customers may result in higher levels of delinquencies and losses. During the first quarter of 2009, ASB recorded a provision for loan losses of $8.3 million due to an increase in nonperforming residential lot loans and residential mortgages and the reclassification of one commercial loan.

(in thousands)	Three months ended March 31 2010	Three months ended March 31 2009	Year ended December 31 2009
Allowance for loan losses, January 1	$ 41,679	$ 35,798	$ 35,798
Provision for loan losses	5,359	8,300	32,000
Less: net charge-offs	5,738	2,047	26,119
Allowance for loan losses, end of period	$ 41,300	$ 42,051	$ 41,679
Ratio of allowance for loan losses, end of period, to end of period loans outstanding	1.13%	1.04%	1.12%
Ratio of net charge-offs during the period to average loans outstanding (annualized)	0.62%	0.20%	0.66%
Nonaccrual loans	$ 68,469	$ 54,627	$ 65,323

First quarter of 2010 noninterest income increased by $1.6 million, or 10%, when compared to the first quarter of 2009, primarily due to higher deposit liability fees, debit card and financial product fees, partially offset by lower gain on sale of loans.

Three months ended March 31 (in thousands)	2010	2009
Fees from other financial services	$ 6,414	$ 5,919
Fee income on deposit liabilities	7,520	6,711
Fee income on other financial products	1,525	1,044
Other income		
Gain on sale of loans	1,042	1,508
Bank-owned life insurance	1,006	987
Other	345	95
Total noninterest income	$ 17,852	$ 16,264

Noninterest expense for the first quarter of 2010 decreased by $3.8 million, or 9%, when compared to the first quarter 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.

Three months ended March 31 (in thousands)	2010	2009
Compensation and benefits	$ 17,402	$ 19,360
Occupancy	4,225	5,129
Data processing	4,338	3,187
Services	1,728	3,418
Equipment	1,709	2,790

Other		
FDIC insurance premium	1,659	1,472
Marketing	954	671
Office supplies, printing and postage	867	1,003
Communication	497	706
Other	4,591	4,075
Total noninterest expense	$ 37,970	$ 41,811

Legislation and regulation. ASB is subject to extensive regulation, principally by the Office of Thrift Supervision (OTS) and the Federal Deposit Insurance Corporation (FDIC). Depending on its level of regulatory capital and other considerations, these regulations could restrict the ability of ASB to compete with other institutions and to pay dividends to its shareholders. See the 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.

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On June 17, 2009, the U. S. Department of the Treasury released *Financial Regulatory Reform: A New Foundation (Proposal)*. The Proposal, if adopted in its current form, would eliminate the OTS and the federal thrift charter. On December 11, 2009, the House of Representatives passed the Wall Street Reform and Consumer Protection Act of 2009, which also would abolish the OTS and transfer its functions and personnel to a division within the Office of the Comptroller of the Currency.

The Proposal identified a number of so-called loopholes in the current regulatory framework that allowed certain types of companies to control insured depository institutions without being subject to comprehensive holding company regulation by the Federal Reserve. Among these loopholes is the grandfathering treatment for certain companies that owned thrifts prior to 1999. HEI relies on this grandfathering treatment to conduct both electric utility and banking activities. The Proposal states: [A]lthough [bank holding companies] generally are prohibited from engaging in commercial activities, many thrift holding companies established before the GLB [Gramm-Leach-Bliley] Act in 1999 qualify as unitary thrift holding companies and are permitted to engage freely in commercial activities. Under our plan, all thrift holding companies would become [bank holding companies] and would be fully regulated on a consolidated basis. The Proposal indicates that such firms would be given five years to conform to the activity limits of the Bank Holding Company Act, such as by divesting their commercial affiliates. Through the Wall Street Reform and Consumer Protection Act of 2009 (H. R. 4173 of the 111th Congress, 1st Session), however, the Congress is continuing the discussion of grandfathered bank holding companies in the context of the Gramm-Leach-Bliley Act of 1999 (the Gramm Act). Management will continue to follow this issue closely as adoption of this legislation or the Proposal could result in HEI being required to divest ASB.

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.

FHLB of Seattle stock. As of March 31, 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 a net loss of $162 million for 2009. Despite the loss, the FHLB of Seattle reported retained earnings of $53 million and was in compliance with all of its regulatory capital requirements, including its risk-based capital requirement as of December 31, 2009. 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 $98 million of FHLB of Seattle stock in 2009 or the first quarter 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 9 of HEI s Notes to Consolidated Financial Statements.

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FINANCIAL CONDITION

Liquidity and capital resources.

(in millions)	March 31, 2010	December 31, 2009	% change
Total assets	$ 4,926	$ 4,941	
Available-for-sale investment and mortgage-related securities	584	433	35
Loans receivable, net	3,623	3,670	(1)
Deposit liabilities	4,008	4,059	(1)
Other bank borrowings	294	298	(1)

As of March 31, 2010, ASB was one of Hawaii s largest financial institutions based on assets of $4.9 billion and deposits of $4.0 billion.

In March 2007, Moody s raised ASB s counterparty credit rating to A3 from Baa3 and, in March 2009, changed ASB s outlook to negative from stable, based on the impact of the current housing and economic crisis on the entire banking industry. 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 May 2009 maintained the rating following its annual review of ASB. These 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.

As of March 31, 2010, ASB s unused FHLB borrowing capacity was approximately $1.5 billion. As of March 31, 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 March 31, 2010 and December 31, 2009, ASB had $68.5 million and $65.3 million of loans on nonaccrual status, respectively, or 1.9% and 1.8% of net loans outstanding, respectively.

As of March 31, 2010 and December 31, 2009, ASB had $4.2 million and $4.0 million, respectively, of real estate acquired in settlement of loans.

For the first quarter of 2010, net cash provided by ASB s operating activities was $34 million. Net cash used during the same period by ASB s investing activities was $83 million, primarily due to purchases of investment securities of $170 million, offset by a net decrease in loans receivable of $38 million and repayments of investment and mortgage-related securities of $48 million. Net cash used in financing activities during this period was $69 million, primarily due to net decreases in deposit liabilities, escrow deposits and retail repurchase agreements of $50 million, $4 million and $3 million, respectively, and the payment of $11 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 March 31, 2010, ASB was well-capitalized (minimum ratio requirements noted in parentheses) with a leverage ratio of 9.1% (5.0%), a Tier-1 risk-based capital ratio of 12.9% (6.0%) and a total risk-based capital ratio of 14.0% (10.0%). OTS approval is required before ASB can make a capital distribution to HEI.

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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 three months ended March 31, 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.

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

	March 31, 2010			December 31, 2009		
Change in interest rates (basis points)	Change in NII Gradual change	NPV ratio Instantaneous change	NPV ratio sensitivity* Instantaneous change	Change in NII Gradual change	NPV ratio Instantaneous change	NPV ratio sensitivity* Instantaneous change
+300	(0.0)	11.06	(261)	(0.3)%	10.92%	(245)
+200	(0.1)	12.09	(158)	(0.3)	11.86	(151)
+100	(0.1)	13.03	(64)	(0.2)	12.72	(65)
Base		13.67			13.37	
-100	(0.9)	13.69	2	(0.9)	13.53	16
-200	**	**	**	**	**	**
-300	**	**	**	**	**	**

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

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

From December 31, 2009 to March 31, 2010, ASB s net interest income (NII) sensitivity became less liability sensitive in the rising rate scenarios primarily due to changes in ASB s balance sheet mix.

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

ASB s NPV ratio sensitivity measure as of March 31, 2010 was relatively unchanged compared to December 31, 2009.

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

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risk. The simulation does not contemplate any actions that ASB management might undertake in response to changes in interest rates. Further, the changes in NII vary in the twelve-month simulation period and are not necessarily evenly distributed over the period. These analyses are for analytical purposes only and do not represent management s views of future market movements, the level of future earnings, or the timing of any changes in earnings within the twelve month analysis horizon. The actual impact of changes in interest rates on NII will depend on the magnitude and speed with which rates change, actual changes in ASB s balance sheet, and management s responses to the changes in interest rates.

Item 4. Controls and Procedures

HEI:

Changes in Internal Control over Financial Reporting

During the first quarter of 2010, there was no change 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 March 31, 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 March 31, 2010. Based on their evaluations, as of March 31, 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 first 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 March 31, 2009 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 March 31, 2010. Based on their evaluations, as of March 31, 2010, they have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective in ensuring that information required to be disclosed by HECO in reports HECO files or submits under the Securities Exchange Act of 1934:

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

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

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PART II - OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

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

Item 5. Other Information

A. Ratio of earnings to fixed charges.

	Three months ended March 31		Years ended December 31				
	2010	**2009**	**2009**	**2008**	**2007**	**2006**	**2005**
HEI and Subsidiaries							
Excluding interest on ASB deposits	2.78	2.31	2.31				