HAWAIIAN ELECTRIC CO INC
Form 10-Q
November 02, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2009

OR

¨ **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 ¨

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 ¨

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 ¨ No ¨

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 ¨ No ¨

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 ¨ 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 ¨ No x

APPLICABLE ONLY TO CORPORATE ISSUERS:

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

Class of Common Stock	**Outstanding October 27, 2009**

Hawaiian Electric Industries, Inc. (Without Par Value)	**92,060,118 Shares**
Hawaiian Electric Company, Inc. ($6-2/3 Par Value)	**12,805,843 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	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

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Hawaiian Electric Industries, Inc. and Subsidiaries

Hawaiian Electric Company, Inc. and Subsidiaries

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Hawaiian Electric Industries, Inc. and Subsidiaries

Hawaiian Electric Company, Inc. and Subsidiaries

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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.). 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.; 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
federal	U.S. Government
FHLB	Federal Home Loan Bank

GAAP	U.S. generally accepted accounting principles
HCEI	Hawaii Clean Energy Initiative

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GLOSSARY OF TERMS, continued

Terms	**Definitions**
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., 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.) (in dissolution), 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
HREA	Hawaii Renewable Energy Alliance
IPP	Independent power producer
IRP	Integrated resource plan
Kalaeloa	Kalaeloa Partners, L.P.
kV	Kilovolt
kw	Kilowatts
KWH	Kilowatthour
MECO	Maui Electric Company, Limited, an electric utility subsidiary of Hawaiian Electric Company, Inc.
MW	Megawatt/s (as applicable)
NII	Net interest income
NPV	Net portfolio value
NQSO	Nonqualified stock option
O&M	Operation and maintenance
OPEB	Postretirement benefits other than pensions
OTS	Office of Thrift Supervision, Department of Treasury
OTTI	Other-than-temporary impairment
PBF	Public benefits fund
PPA	Power purchase agreement
PRPs	Potentially responsible parties
PUC	Public Utilities Commission of the State of Hawaii
RBA	Revenue balancing account
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. In addition, any statements concerning future financial performance, ongoing business strategies or prospects and possible future actions are also forward-looking statements. Forward-looking statements are based on current expectations and projections about future events and are subject to risks, uncertainties and the accuracy of assumptions concerning HEI and its subsidiaries (collectively, the Company), the performance of the industries in which they do business and economic and market factors, among other things. **These forward-looking statements are not guarantees of future performance.**

Risks, uncertainties and other important factors that could cause actual results to differ materially from those in forward-looking statements and from historical results include, but are not limited to, the following:

- 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 and mortgage-related securities held by American Savings Bank, F.S.B. (ASB), which could result in higher loan loss provisions and write-offs and material other-than-temporary impairment (OTTI) charges), 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 (plan for a $700 billion bailout of the financial industry) and the American Economic Recovery and Reinvestment Act of 2009 (economic stimulus package);

- weather and natural disasters, such as hurricanes, earthquakes, tsunamis, lightning strikes and the potential effects of global warming;

- global developments, including terrorist acts, the war on terrorism, continuing U.S. presence in Iraq and Afghanistan, potential conflict or crisis with North Korea and in the Middle East, 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 common stock (HEI) 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;

- 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 PUC approvals needed; the PUC s delay in considering HCEI-related costs; reliance on outside parties like the state, independent power producers (IPPs) and developers; potential changes in political support; and uncertainties surrounding wind power, the 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;

increased risk to generation reliability as generation peak reserve margins on Oahu continue to be strained;

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

the impact on customer satisfaction and political and regulatory support resulting from volatility in fuel prices;

the risks associated with increasing reliance on renewable energy, as contemplated under the Energy Agreement, including the availability 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;

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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 potential regulation of greenhouse gas emissions (GHG), 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 1998 that have permitted HEI to own ASB);

decisions by the Public Utilities Commission of the State of Hawaii (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 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 the Bank Secrecy Act or other regulatory requirements 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 initiatives, 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 and investments, ASB s concentration in a single product type (first mortgages), ASB s significant credit relationships (i.e., concentrations of large loans and/or credit lines with certain customers) and Alt-A exposure in ASB s mortgage-related securities portfolio;

changes in accounting principles applicable to HEI, HECO, ASB and their subsidiaries, including the adoption of International Financial Reporting Standards or new U.S. accounting standards, continued 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;

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

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

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

- other risks or uncertainties described elsewhere in this report and in other reports (e.g., Item 1A. Risk Factors in the Company s Annual Report on Form 10-K) previously and subsequently filed by HEI and/or HECO with the Securities and Exchange Commission (SEC).

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

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements
Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

(in thousands, except per share amounts and ratio of earnings to fixed charges)	Three months ended September 30 2009	Three months ended September 30 2008	Nine months ended September 30 2009	Nine months ended September 30 2008
Revenues				
Electric utility	$ 548,440	$ 827,788	$ 1,460,654	$ 2,139,798
Bank	71,947	87,675	229,478	279,469
Other	(74)	(32)	(121)	(164)
	620,313	**915,431**	**1,690,011**	**2,419,103**
Expenses				
Electric utility	494,268	775,941	1,343,250	1,981,572
Bank	54,258	62,983	189,162	262,406
Other	3,148	2,378	9,247	8,648
	551,674	**841,302**	**1,541,659**	**2,252,626**
Operating income (loss)				
Electric utility	54,172	51,847	117,404	158,226
Bank	17,689	24,692	40,316	17,063
Other	(3,222)	(2,410)	(9,368)	(8,812)
	68,639	**74,129**	**148,352**	**166,477**
Interest expense other than on deposit liabilities and other bank borrowings	(19,678)	(19,345)	(55,421)	(56,780)
Allowance for borrowed funds used during construction	1,118	967	4,467	2,564
Allowance for equity funds used during construction	2,628	2,426	10,353	6,432
Income before income taxes	**52,707**	**58,177**	**107,751**	**118,693**
Income taxes	18,753	20,425	36,977	40,892
Net income	**33,954**	**37,752**	**70,774**	**77,801**
Less net income attributable to noncontrolling interest - preferred stock of subsidiaries	471	471	1,417	1,417
Net income for common stock	**$ 33,483**	**$ 37,281**	**$ 69,357**	**$ 76,384**
Basic earnings per common share	$ 0.37	$ 0.44	$ 0.76	$ 0.91
Diluted earnings per common share	$ 0.37	$ 0.44	$ 0.76	$ 0.91
Dividend per common share	$ 0.31	$ 0.31	$ 0.93	$ 0.93

Weighted-average number of common shares outstanding	91,522	84,625	91,173	84,052
Dilutive effect of stock-based compensation	131	217	105	130
Adjusted weighted-average shares	91,653	84,842	91,278	84,182
Ratio of earnings to fixed charges (SEC method)				
Excluding interest on ASB deposits			2.49	2.11
Including interest on ASB deposits			2.05	1.76

For the three and nine months ended September 30, 2009, under the two-class method of computing basic and diluted earnings per share, distributed earnings were $0.31 and $0.93 per share, respectively, and undistributed earnings (loss) were $0.06 and $(0.17) per share, respectively, for both unvested restricted stock awards and unrestricted common stock. For the three and nine months ended September 30, 2008, under the two-class method of computing basic and diluted earnings per share, distributed earnings were $0.31 and $0.93 per share, respectively, and undistributed earnings (loss) were $0.13 and $(0.02) per share, respectively, for both unvested restricted stock awards and unrestricted common stock.

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Balance Sheets (unaudited)

(dollars in thousands)	September 30, 2009	December 31, 2008
Assets		
Cash and equivalents	$ 257,331	$ 182,903
Federal funds sold	1,708	532
Accounts receivable and unbilled revenues, net	252,186	300,666
Available-for-sale investment and mortgage-related securities	623,104	657,717
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,758,898	4,206,492
Property, plant and equipment, net of accumulated depreciation of $1,918,984 and $1,851,813	3,052,209	2,907,376
Regulatory assets	535,287	530,619
Other	344,336	328,823
Goodwill, net	82,190	82,190
	$ 9,005,013	$ 9,295,082
Liabilities and stockholders equity		
Liabilities		
Accounts payable	$ 182,943	$ 183,584
Deposit liabilities	4,047,940	4,180,175
Other bank borrowings	367,884	680,973
Long-term debt, net other than bank	1,364,784	1,211,501
Deferred income taxes	162,452	143,308
Regulatory liabilities	282,239	288,602
Contributions in aid of construction	315,455	311,716
Other	825,115	871,476
	7,548,812	7,871,335
Stockholders equity		
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding: 92,014,738 shares and 90,515,573 shares	1,254,893	1,231,629
Retained earnings	199,118	210,840
Accumulated other comprehensive loss, net of tax benefits	(32,103)	(53,015)
Common stock equity	1,421,908	1,389,454
Preferred stock, no par value, authorized 10,000,000 shares; issued: none		
Noncontrolling interest: cumulative preferred stock of subsidiaries - not subject to mandatory redemption	34,293	34,293
	1,456,201	1,423,747
	$ 9,005,013	$ 9,295,082

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)

	Common stock		Retained	Accumulated other comprehensive	Noncontrolling interest: cumulative preferred stock of	
(in thousands, except per share amounts)	**Shares**	**Amount**	**earnings**	**loss**	**subsidiaries**	**Total**
Balance, December 31, 2008	**90,516**	**$ 1,231,629**	**$ 210,840**	**$ (53,015)**	**$ 34,293**	**$ 1,423,747**
Cumulative effect of adoption of a standard on other-than-temporary impairment recognition, net of taxes of $2,497			3,781	(3,781)		
Comprehensive income:						
Net income			69,357		1,417	70,774
Net unrealized gains (losses) on securities:						
Net unrealized gains on securities arising during the period, net of taxes of $16,248				24,607		24,607
Net unrealized losses related to factors other than credit arising during the period, net of tax benefits of $6,650				(10,072)		(10,072)
Add: reclassification adjustment for net realized losses included in net income, net of tax benefits of $6,125				9,276		9,276
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $5,562				8,717		8,717
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $4,990				(7,835)		(7,835)
Comprehensive income			69,357	24,693	1,417	95,467
Issuance of common stock, net	1,499	23,264				23,264
Common stock dividends ($0.93 per share)			(84,860)			(84,860)
Preferred stock dividends					(1,417)	(1,417)
Balance, September 30, 2009	**92,015**	**$ 1,254,893**	**$ 199,118**	**$ (32,103)**	**$ 34,293**	**$ 1,456,201**
Balance, December 31, 2007	**83,432**	**$ 1,072,101**	**$ 225,168**	**$ (21,842)**	**$ 34,293**	**$ 1,309,720**
Comprehensive income:						
Net income			76,384		1,417	77,801
Net unrealized losses on securities:						
Net unrealized losses on securities arising during the period, net of tax benefits of $1,842				(2,788)		(2,788)
Add: reclassification adjustment for net realized losses included in net income, net of tax benefits of $6,915				10,472		10,472
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $2,775				4,358		4,358
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits				(3,928)		(3,928)

of $2,501						
Comprehensive income			76,384	8,114	1,417	85,915
Issuance of common stock, net	1,649	38,933				38,933
Common stock dividends ($0.93 per share)			(78,258)			(78,258)
Preferred stock dividends					(1,417)	(1,417)
Balance, September 30, 2008	**85,081**	**$ 1,111,034**	**$ 223,294**	**$ (13,728)**	**$ 34,293**	**$ 1,354,893**

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Cash Flows (unaudited)

Nine months ended September 30 **(in thousands)**	**2009**	**2008**
Cash flows from operating activities		
Net income	$ 70,774	$ 77,801
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	113,916	113,423
Other amortization	4,037	3,927
Provision for loan losses	27,000	4,034
Loans receivable originated and purchased, held for sale	(368,880)	(159,327)
Proceeds from sale of loans receivable, held for sale	400,213	157,293
Net loss (gain) on sale of investment and mortgage-related securities	(44)	17,388
Other-than-temporary impairment of available-for-sale mortgage-related securities	15,444	
Changes in deferred income taxes	2,958	12,186
Changes in excess tax benefits from share-based payment arrangements	324	(572)
Allowance for equity funds used during construction	(10,353)	(6,432)
Changes in assets and liabilities		
Decrease (increase) in accounts receivable and unbilled revenues, net	48,480	(76,034)
Decrease (increase) in fuel oil stock	9,826	(79,693)
Increase (decrease) in accounts payable	(641)	54,460
Changes in prepaid and accrued income taxes and utility revenue taxes	(50,514)	(29,640)
Changes in other assets and liabilities	(35,561)	(13,278)
Net cash provided by operating activities	**226,979**	**75,536**
Cash flows from investing activities		
Available-for-sale investment and mortgage-related securities purchased	(247,425)	(411,658)
Principal repayments on available-for-sale investment and mortgage-related securities	304,728	489,740
Proceeds from sale of available-for-sale investment and mortgage-related securities	44	1,291,609
Net decrease (increase) in loans held for investment	396,706	(55,828)
Capital expenditures	(239,441)	(172,948)
Contributions in aid of construction	7,472	12,266
Other	426	724
Net cash provided by investing activities	**222,510**	**1,153,905**
Cash flows from financing activities		
Net decrease in deposit liabilities	(132,234)	(164,612)
Net increase in short-term borrowings with original maturities of three months or less		138,786
Net decrease in retail repurchase agreements	(18,573)	(23,290)
Proceeds from other bank borrowings	310,000	1,719,085
Repayments of other bank borrowings	(604,517)	(2,820,119)
Proceeds from issuance of long-term debt	153,186	18,707
Repayment of long-term debt		(50,000)
Changes in excess tax benefits from share-based payment arrangements	(324)	572
Net proceeds from issuance of common stock	11,004	21,067
Common stock dividends	(73,931)	(62,493)
Preferred stock dividends of noncontrolling interest	(1,417)	(1,417)
Decrease in cash overdraft	(9,847)	(8,582)
Other	(7,232)	(5,252)

Net cash used in financing activities	**(373,885)**	**(1,237,548)**
Net increase (decrease) in cash and equivalents and federal funds sold	75,604	(8,107)
Cash and equivalents and federal funds sold, beginning of period	183,435	209,855
Cash and equivalents and federal funds sold, end of period	**$ 259,039**	**$ 201,748**

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 should be read in conjunction with the audited consolidated financial statements and the notes thereto filed in HEI Exhibit 99.1 to HEI s Form 8-K dated June 9, 2009 and the unaudited consolidated financial statements and the notes thereto in HEI s Quarterly Reports on SEC Form 10-Q for the quarters ended March 31, 2009 and June 30, 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 September 30, 2009 and December 31, 2008, the results of its operations for the three and nine months ended September 30, 2009 and 2008 and cash flows for the nine months ended September 30, 2009 and 2008. All such adjustments are of a normal recurring nature, unless otherwise disclosed in this Form 10-Q or other referenced material. Results of operations for interim periods are not necessarily indicative of results for the full year. When required, certain reclassifications are made to the prior period s consolidated financial statements to conform to the current presentation.

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2 Segment financial information

(in thousands)	Electric Utility	Bank	Other	Total
Three months ended September 30, 2009				
Revenues from external customers	$ 548,373	$ 71,947	$ (7)	$ 620,313
Intersegment revenues (eliminations)	67		(67)	
Revenues	548,440	71,947	(74)	620,313
Profit (loss)*	42,877	17,665	(7,835)	52,707
Income taxes (benefit)	15,865	6,342	(3,454)	18,753
Net income (loss)	27,012	11,323	(4,381)	33,954
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	498		(27)	471
Net income (loss) for common stock	26,514	11,323	(4,354)	33,483
Nine months ended September 30, 2009				
Revenues from external customers	1,460,515	229,478	18	1,690,011
Intersegment revenues (eliminations)	139		(139)	
Revenues	1,460,654	229,478	(121)	1,690,011
Profit (loss)*	90,626	40,239	(23,114)	107,751
Income taxes (benefit)	32,989	14,013	(10,025)	36,977
Net income (loss)	57,637	26,226	(13,089)	70,774
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	1,496		(79)	1,417
Net income (loss) for common stock	56,141	26,226	(13,010)	69,357
Assets (at September 30, 2009)	3,974,879	4,997,723	32,411	9,005,013
Three months ended September 30, 2008				
Revenues from external customers	$ 827,731	$ 87,675	$ 25	$ 915,431
Intersegment revenues (eliminations)	57		(57)	
Revenues	827,788	87,675	(32)	915,431
Profit (loss)*	41,377	24,607	(7,807)	58,177
Income taxes (benefit)	14,947	9,202	(3,724)	20,425
Net income (loss)	26,430	15,405	(4,083)	37,752
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	498		(27)	471
Net income (loss) for common stock	25,932	15,405	(4,056)	37,281
Nine months ended September 30, 2008				
Revenues from external customers	2,139,667	279,469	(33)	2,419,103

Intersegment revenues (eliminations)	131		(131)	
Revenues	2,139,798	279,469	(164)	2,419,103
Profit (loss)*	126,510	16,934	(24,751)	118,693
Income taxes (benefit)	47,065	5,046	(11,219)	40,892
Net income (loss)	79,445	11,888	(13,532)	77,801
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	1,496		(79)	1,417
Net income (loss) for common stock	77,949	11,888	(13,453)	76,384
Assets (at September 30, 2008)	3,692,204	5,514,788	33,935	9,240,927

* Income (loss) before income taxes.

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

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

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3 Electric utility subsidiary

For HECO s consolidated financial information, including its commitments, contingencies and subsequent events, see pages 23 through 55.

4 Bank subsidiary

Selected financial information

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

Consolidated Statements of Income Data (unaudited)

(in thousands)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Interest and dividend income				
Interest and fees on loans	$ 53,080	$ 61,100	$ 166,535	$ 186,312
Interest and dividends on investment and mortgage-related securities	6,943	9,898	21,762	57,078
	60,023	70,998	188,297	243,390
Interest expense				
Interest on deposit liabilities	7,286	14,070	28,753	47,909
Interest on other borrowings	2,205	4,616	7,710	40,030
	9,491	18,686	36,463	87,939
Net interest income	**50,532**	**52,312**	**151,834**	**155,451**
Provision for loan losses	5,200	1,979	27,000	4,034
Net interest income after provision for loan losses	**45,332**	**50,333**	**124,834**	**151,417**
Noninterest income				
Fee income on deposit liabilities	8,211	7,328	22,384	20,889
Fees from other financial services	6,385	6,318	18,747	18,554
Fee income on other financial products	1,613	1,771	4,285	5,214
Net losses on available-for-sale securities (includes impairment losses of $9,863 and $15,444, consisting of $13,645 and $32,167 of total other-than-temporary impairment losses, net of $3,782 and $16,723 of non-credit losses recognized in other comprehensive income, for the quarter and nine months ended September 30, 2009, respectively)	(9,863)		(15,400)	(17,388)
Other income	5,578	1,260	11,165	8,810
	11,924	16,677	41,181	36,079
Noninterest expense				
Compensation and employee benefits	17,721	19,172	55,072	56,451
Occupancy	4,905	5,489	15,956	16,276
Data processing	3,684	2,794	10,352	8,019
Services	2,437	3,688	9,656	13,531
Equipment	1,782	3,175	7,112	9,510
Loss on early extinguishment of debt			101	39,843
Other expense	9,062	8,085	27,527	26,932

	39,591	42,403	125,776	170,562
Income before income taxes	**17,665**	**24,607**	**40,239**	**16,934**
Income taxes	6,342	9,202	14,013	5,046
Net income	**$ 11,323**	**$ 15,405**	**$ 26,226**	**$ 11,888**

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

Consolidated Balance Sheets Data (unaudited)

(in thousands)	September 30, 2009	December 31, 2008
Assets		
Cash and equivalents	$ 222,286	$ 168,766
Federal funds sold	1,708	532
Available-for-sale investment and mortgage-related securities	623,104	657,717
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,758,898	4,206,492
Other	211,773	223,659
Goodwill, net	82,190	82,190
	$ 4,997,723	$ 5,437,120
Liabilities and stockholder s equity		
Deposit liabilities noninterest-bearing	$ 751,893	$ 701,090
Deposit liabilities interest-bearing	3,296,047	3,479,085
Other borrowings	367,884	680,973
Other	91,643	98,598
	4,507,467	4,959,746
Common stock	329,292	328,162
Retained earnings	188,437	197,235
Accumulated other comprehensive loss, net of tax benefits	(27,473)	(48,023)
	490,256	477,374
	$ 4,997,723	$ 5,437,120

Other borrowings consisted of securities sold under agreements to repurchase and advances from the Federal Home Loan Bank (FHLB) of Seattle of $218 million and $150 million, respectively, as of September 30, 2009 and $241 million and $440 million, respectively, as of December 31, 2008.

As of September 30, 2009, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.2 billion.

Balance sheet restructure. In June 2008, ASB undertook and substantially completed a restructuring of its balance sheet through the sale of mortgage-related securities and agency notes and the early extinguishment of certain borrowings to strengthen future profitability ratios and enhance future net interest margin, while remaining well-capitalized and without significantly impacting future net income and interest rate risk. On June 25, 2008, ASB completed a series of transactions which resulted in the sales to various broker/dealers of available-for-sale agency and private-issue mortgage-related securities and agency notes with a weighted average yield of 4.33% for approximately $1.3 billion. ASB used the proceeds from the sales of these mortgage-related securities and agency notes to retire debt with a weighted average cost of 4.70%, comprised of approximately $0.9 billion of FHLB advances and $0.3 billion of securities sold under agreements to repurchase. These transactions resulted in a charge to net income of $35.6 million in the second quarter of 2008. The $35.6 million is comprised of: (1) realized losses on the sale of mortgage-related securities and agency notes of $19.3 million included in Noninterest income-Net losses on available-for-sale securities, (2) fees associated with the early retirement of other bank borrowings of $39.8 million included in Noninterest expense-Loss on early extinguishment of debt and (3) income tax benefits of $23.5 million included in Income taxes. Although the sales of the mortgage-related securities and agency notes resulted in realized losses in the second quarter of 2008, a portion of the losses on these available-for-sale securities had been previously recognized as unrealized losses in ASB s equity as a result of mark-to-market charges to other comprehensive income in earlier periods.

ASB subsequently purchased approximately $0.3 billion of short-term agency notes and entered into approximately $0.2 billion of FHLB advances to facilitate the timing of the release of certain collateral. These notes and advances had original maturities up to December 31, 2008.

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As a result of this balance sheet restructuring, ASB freed up capital and paid a dividend of approximately $55 million to HEI in 2008. HEI used the dividend to repay commercial paper and for other corporate purposes. The OTS has approved ASB s payment of quarterly dividends through the quarter ended September 30, 2010 to the extent that payment of the dividend would not cause ASB s Tier I leverage and total risk-based capital ratios to fall below 8% and 12%, respectively, as of the end of the quarter.

Investment and mortgage-related securities portfolio

Available-for-sale securities

The following table details the book value and aggregate fair value by major security type at September 30, 2009:

September 30, 2009

(in thousands)	Book value	Gross unrealized gains	Gross unrealized losses	Fair value
U.S. Treasury and U.S. agency debentures	$ 63,782	$ 76	$ (24)	$ 63,834
Municipal bonds	6,303	18	(9)	6,312
Mortgage-related securities:				
Federal agencies	341,670	10,388	(22)	352,036
Private-issue	232,926	408	(32,412)	200,922
	$ 644,681	$ 10,890	$ (32,467)	$ 623,104

The following table details 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.

September 30, 2009

			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 (%)
U.S. Treasury and U.S. agency debentures	$ 63,782	0.95	$		$ 53,782	0.80	$ 10,000	1.80	$	
Municipal bonds	6,303	1.38	5,003	1.15	1,300	2.27				
Mortgage-related securities:										
Federal agencies	341,670	3.83			6,436	2.33	148,154	3.80	187,080	3.91
Private-issue	232,926	5.18					28,795	4.21	204,131	5.32
	$ 644,681	4.01	$ 5,003	1.15	$ 61,518	0.99	$ 186,949	3.75	$ 391,211	4.64

Gross unrealized losses and fair value

The following table details 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. Positions for which OTTIs have been identified are categorized based upon the point at which unrealized losses were identified, not the point at which write-downs have occurred.

September 30, 2009

	Less than 12 months	12 months or more	Total

(in thousands)	Gross unrealized losses	Fair value	Gross unrealized losses	Fair value	Gross unrealized losses	Fair value
U.S. Treasury and U.S. agency debentures	$ (24)	$ 30,002	$	$	$ (24)	$ 30,002
Municipal bonds	(9)	4,994			(9)	4,994
Mortgage-related securities:						
Federal agencies	(22)	10,216			(22)	10,216
Private-issue	(781)	11,468	(31,631)	183,553	(32,412)	195,021
	$ (836)	$ 56,680	$ (31,631)	$ 183,553	$ (32,467)	$ 240,233

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The unrealized losses on ASB s investments in U.S. Treasury and agency debentures and mortgage-related securities 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 it is not more likely than not that ASB will be required to sell the investments before recovery of their amortized costs bases, which may be at maturity, ASB does not consider these investments to be other-than-temporarily impaired at September 30, 2009.

The unrealized losses on ASB s investments in municipal bonds are primarily driven by interest rates and not due to the credit of the securities. All municipal obligations held in this portfolio are of investment grade and have been reviewed based on the credit of the underlying issuer. Based upon ASB s initial and ongoing review of these credits, ASB does not consider these investments to be other-than-temporarily impaired at September 30, 2009.

The unrealized losses on ASB s investments in private-issue mortgage-related securities is exemplary of the credit pressures in that sector. Positions are regularly monitored to track delinquency pipelines/trends, prepayment speeds and realized losses. Marginal positions are reviewed using management s expectations of loss severity, constant default rates and prepayment speeds based upon deal performance, collateral characteristics and cohort vintage performance. Exclusive of positions detailed below which have incurred OTTIs, because ASB does not intend to sell the securities and it is not more likely than not that ASB will be required to sell the investments before recovery of their amortized costs bases, which may be at maturity, ASB does not consider these investments to be other-than-temporarily impaired at September 30, 2009.

The fair values of ASB s investment securities could continue to decline if the current economic environment continues to deteriorate. While the performance of ASB s private-issue mortgage-related securities are intrinsically tied to the economy, excess leverage in that sector coupled with weak underwriting of recent vintages could also pressure ASB s positions even if the economy recovers. Despite ASB s best estimate expectation of performance of ASB s positions, economic uncertainty coupled with a very fragile housing market could result in material OTTIs.

Other-than-temporary impaired securities

All securities are reviewed for impairment in accordance with U.S. standards for OTTI recognition. Under these standards ASB s intent to sell the security, the probability of more-likely-than-not being forced to sell the position prior to recovery of its cost basis and the probability of more-likely-than-not recovering the amortized cost of the position was determined. Because of ASB s intent to hold all positions determined to be other-than-temporarily impaired, credit losses, which are recognized in earnings, were quantified using the position s pre-impairment discount rate and the net present value of these losses. Non-credit related impairments are reflected in other comprehensive income.

The following table reflects cumulative OTTIs for expected losses that have been recognized in earnings. The beginning balance for the six months ended September 30, 2009 relates to credit losses realized prior to April 1, 2009 on debt securities held by ASB as of March 31, 2009. This beginning balance includes the net impact of non-credit losses that were originally reported as losses prior to March 31, 2009 and were subsequently recharacterized from retained earnings as a result of the adoption of new U.S. standards for OTTI recognition effective April 1, 2009. Additions to this balance include new securities in which initial credit impairments have been identified and incremental increases of credit impairments on positions that had already taken similar impairments.

(in thousands)	**Three months ended September 30, 2009**	**Six months ended September 30, 2009**
Balance, beginning of period	$ 7,067	$ 1,486
Additions:		
Initial credit impairments	2,661	4,870
Subsequent credit impairments	7,202	10,574
Balance, end of period	$ 16,930	$ 16,930

In the third quarter of 2009, management identified eleven securities in which credit-related OTTIs were recognized. All of the positions are private-issue mortgage related securities, including eight securities in which credit impairments were recognized for the first time and three securities in which additional credit impairments were recognized. Credit related losses for private-issue mortgage-related securities are determined through

management s estimation of various inputs, such as prepayment speeds, default rates and loss severities, which impact the generation of future cash flows. Forward projections of economic activity and national housing market trends impact assumptions used in this assessment. All estimates are determined based on specific characteristics of each pool performance and security structure:

Prepayment speeds prepayment speed estimates are based upon historic performance, comparable collateral trends and the refinance ability of borrowers.

Default rates default rate estimates are based on historic performance, the current/future delinquency pipelines and estimates of the rate at which delinquent loans will default.

Gross losses % current balance this ratio provides management s gross expectation of loss divided by the current remaining balance held. Factors which impact these losses include the current/future delinquency pipeline, historical performance, performance of peer collateral and specific collateral characteristics which include geographic concentration, year of origination, FICO scores and loan type.

Fair Value Measurements. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. ASB grouped its financial assets measured at fair value in three levels outlined as follows:

Level 1: Inputs to the valuation methodology are quoted prices, unadjusted, for identical assets or liabilities in active markets. A quoted price in an active market provides the most reliable evidence of fair value and shall be used to measure fair value whenever available.

Level 2: Inputs to the valuation methodology include quoted prices for similar assets or liabilities in active markets; inputs to the valuation methodology include quoted prices for identical or similar assets or liabilities in markets that are not active; or inputs to the valuation methodology that are derived principally from or can be corroborated by observable market data by correlation or other means.

Level 3: Inputs to the valuation methodology are unobservable and significant to the fair value measurement. Level 3 assets and liabilities include financial instruments whose value is determined using discounted cash flow methodologies, as well as instruments for which the determination of fair value requires significant management judgment or estimation.

Assets measured at fair value on a recurring basis

Available-for-sale investment and mortgage-related securities. 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.

The table below presents the balances of assets measured at fair value on a recurring basis:

		Fair value measurements using		
(in millions)	**September 30, 2009**	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Available-for-sale securities	$ 623	$	$ 623	$

Assets measured at fair value on a nonrecurring basis

Loans. ASB does not record loans at fair value on a recurring basis. However, from time to time, ASB records nonrecurring fair value adjustments to loans to reflect specific reserves on loans based on the current appraised value of the collateral or unobservable market assumption. These adjustments to fair value usually result from the application of lower-of-cost-or-market accounting or write-downs of individual loans. Unobservable assumptions reflect ASB s own estimate of the fair value of collateral used in valuing the loan.

The table below presents the balances of assets measured at fair value on a nonrecurring basis:

		Fair value measurements using		
(in millions)	September 30, 2009	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Loans	$ 14.6	$	$ 14.6	$

Specific reserves as of September 30, 2009 were $5.2 million and were included in loans receivable held for investment, net. For the nine months ended September 30, 2009, there were no adjustments to fair value for ASB s loans held for sale.

Guarantees. In October 2007, ASB, as a member financial institution of Visa U.S.A. Inc., received restricted shares of Visa, Inc. (Visa) as a result of a restructuring of Visa U.S.A. Inc. in preparation for an initial public offering by Visa. As a part of the restructuring, ASB entered into judgment and loss sharing agreements with Visa in order to apportion financial responsibilities arising from any potential adverse judgment or negotiated settlements related to indemnified litigation involving Visa. In November 2007, Visa announced that it had reached a settlement with American Express regarding part of this litigation. In the fourth quarter of 2007, ASB recorded a charge of $0.3 million for its proportionate share of this settlement and a charge of approximately $0.6 million for potential losses arising from indemnified litigation that has not yet settled, which estimated fair value is highly judgmental. In March 2008, Visa funded an escrow account designed to address potential liabilities arising from litigation covered in the Retrospective Responsibility Plan and, based on the amount funded in the escrow account, ASB recorded income and a receivable of $0.4 million for its proportionate share of the escrow account. In the fourth quarter of 2008, Visa reached a settlement in a case brought by Discover Financial Services. This case is covered litigation under Visa s Retrospective Responsibility Plan and ASB s proportionate share of this settlement is estimated to be $0.2 million. Because the extent of ASB s obligations under this agreement depends entirely upon the occurrence of future events, ASB s maximum potential future liability under this agreement is not determinable.

Federal Deposit Insurance Corporation (FDIC) restoration plan. Under the Federal Deposit Insurance Reform Act of 2005 (the Reform Act), the 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. As of June 30, 2008, the reserve ratio had fallen 18 basis points since the previous quarter to 1.01%. To restore the reserve ratio to 1.15%, higher assessment rates were required. The FDIC made changes to the assessment system to ensure that riskier institutions will bear a greater share of the proposed increase in assessments. Under the final rules, financial institutions in Risk Category I, the lowest risk group, will have an initial base assessment rate within the range of 12 to 16 basis points of deposits. After applying adjustments for unsecured debt, secured liabilities and brokered deposits, the total base assessment rate for financial institutions in Risk Category I would be within the range of 7 to 24 basis points of deposits. The new assessment rates became effective April 1, 2009. The FDIC also raised the current rates uniformly by seven basis points for the assessment for the quarter beginning January 1, 2009. 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. The special assessment was 5 basis points on each institution s total assets, minus its Tier 1 core capital, as of June 30, 2009. Based on the FDIC s formula, ASB s special assessment was $2.3 million and ASB recorded the charge in June 2009. ASB is classified in Risk Category I and its assessment rate was 14 basis points of deposits, or $1.5 million, for the quarter ended September 30, 2009, compared to an assessment rate of 6 basis points of deposits, or $0.6 million (net of a one-time assessment credit), for the quarter ended September 30, 2008. For the nine months ended September 30, 2009, ASB recorded FDIC assessments (excluding the special assessment recorded in June 2009) of $4.3 million, compared to $0.9 million (net of a one-time assessment credit) for the same period in 2008.

In September 2009, the FDIC proposed a restoration plan that requires 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

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2012. For the fourth quarter of 2009 and all of 2010, the prepaid assessment rate would be assessed according to the risk-based premium schedule adopted earlier in 2009. The prepaid assessment rate for 2011 and 2012 would be the current assessment rate plus 3 basis points. The prepaid assessment would be recorded as a prepaid asset as of December 30, 2009, and each quarter thereafter ASB would 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 would 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 would be returned to ASB. ASB s estimated prepaid assessment is approximately $22 million.

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

Deposit insurance coverage. The Emergency Economic Stabilization Act of 2008 was signed into law on October 3, 2008 and temporarily raises the basic limit on federal deposit insurance coverage from $100,000 to $250,000 per depositor, effective October 3, 2008 through December 31, 2009. In May 2009, the FDIC extended the temporary increase in federal deposit insurance coverage through December 31, 2013. The legislation provides that 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. Under the FDIC s Transaction Account Guarantee Program, non-interest bearing deposit transaction accounts will be provided unlimited deposit insurance coverage until December 31, 2009. In August 2009, the FDIC extended the Transaction Account Guarantee Program for six months, through June 30, 2010. Institutions currently participating in the program have the option to continue in the program or opt-out. The annual assessment rate during the extension period will increase from 10 basis points to either 15 basis points, 20 basis points or 25 basis points, depending on the risk category assigned to the institution under the FDIC s risk-based premium system. ASB has elected to remain in the program and the increase in the annual assessment rate is not significant.

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5 Retirement benefits

Defined benefit plans. For the first nine months of 2009, the utilities contributed $19.9 million and HEI contributed $1.0 million to their respective retirement benefit plans, compared to $9.3 million and $0.6 million, respectively, in the first nine months of 2008. The Company s current estimate of contributions to its retirement benefit plans in 2009 is $25 million ($24 million to be made by the utilities, nil by ASB and $1 million by HEI), compared to contributions of $15 million in 2008 ($14 million made by the utilities, nil by ASB and $1 million by HEI). In addition, the Company expects to pay directly $2 million of benefits in 2009, compared to the $1 million paid in 2008.

For the first nine months of 2009, the Company s defined benefit retirement plans assets generated a return, net of investment management fees, of 21.4%. The market value of the defined benefit retirement plans assets as of September 30, 2009 was $851 million compared to $726 million at December 31, 2008, an increase of approximately $125 million.

The components of net periodic benefit cost were as follows:

	Three months ended September 30				Nine months ended September 30			
	Pension benefits		Other benefits		Pension benefits		Other benefits	
(in thousands)	**2009 (1)**	**2008 (1)**	**2009**	**2008**	**2009 (1)**	**2008 (1)**	**2009**	**2008**
Service cost	$ 6,479	$ 7,255	$ 1,427	$ 1,215	$ 19,208	$ 21,100	$ 3,654	$ 3,562
Interest cost	15,468	14,987	2,678	2,690	46,520	44,778	8,363	8,318
Expected return on plan assets	(14,336)	(18,335)	(2,240)	(2,745)	(42,907)	(54,836)	(6,677)	(8,227)
Amortization of unrecognized transition obligation	1		262	785	2	2	1,831	2,354
Amortization of prior service cost (credit)	(100)	(116)	(34)	3	(288)	(305)	(27)	10
Recognized actuarial loss	3,957	1,692	86		11,890	5,073	309	
Net periodic benefit cost	11,469	5,483	2,179	1,948	34,425	15,812	7,453	6,017
Impact of PUC D&Os	(1,776)	1,327	(270)	308	(9,974)	4,531	(1,002)	731
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 9,693	$ 6,810	$ 1,909	$ 2,256	$ 24,451	$ 20,343	$ 6,451	$ 6,748

(1) Effective December 31, 2007, ASB ended the accrual of benefits in, and the addition of new participants to, ASB s defined benefit pension plan. The change to the plan did not affect the vested pension benefits of former participants, including ASB retirees, as of December 31, 2007. All active participants who were employed by ASB on December 31, 2007 became fully vested in their accrued pension benefit as of December 31, 2007. Thus, there are no amounts for ASB employees for certain components (service cost for benefit accruals, amortization of unrecognized transition obligation and amortization of prior service cost (credit)).

The Company recorded retirement benefits expense of $24 million and $20 million in the first nine months of 2009 and 2008, 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 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 negative amendment credit is amortized.

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

Defined contribution plan. On January 1, 2008, ASB began providing matching contributions of 100% on the first 4% of eligible pay contributed by participants to HEI s retirement savings plan for its eligible employees. In addition, a new ASB 401(k) Plan was created effective January 1, 2008. On May 7, 2009, the account balances of ASB participants were transferred from HEI s retirement savings plan to account balances in the newly created ASB 401(k) Plan. $41 million in assets was transferred in-kind between plans. On May 15, 2009, ASB contributed $2.1 million to fund the discretionary employer profit sharing (AmeriShare) portion of the plan 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. This 4% contribution percentage was determined at year-end based on ASB s performance and achievement of financial goals for 2008. For the first nine months of 2009 and 2008, ASB s total expense for its

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employees participating in the HEI retirement savings plan and the ASB 401(k) Plan combined was $2.1 million and $3.3 million, respectively, and cash contributions were $3.4 million and $1.3 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 (4.5 million shares available for issuance under outstanding and future grants and awards as of September 30, 2009) 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 three to five years after the date of grant and are forfeited for terminations of employment during the vesting period, except for terminations by reason of death, disability or termination without cause which allow for pro-rata vesting. 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 for terminations due to death, disability and retirement which allow for pro-rata vesting. 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.

Performance shares granted under the 2009-2011 Long-Term Incentive Plan (LTIP) are based on the achievement of certain financial goals and vest at the end of the three-year performance period. LTIP is forfeited for terminations of employment during the vesting period, except for terminations due to death, disability and retirement which allow for pro-rata vesting based upon completed months of service after a minimum of 12 months of service in the performance period. Compensation expense for the performance shares portion of the 2009-2011 LTIP award has been recognized in accordance with the fair-value based measurement method of accounting for performance shares.

The Company s share-based compensation expense and related income tax benefit (including a valuation allowance due to limits on the deductibility of executive compensation) are as follows:

($ in millions)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Share-based compensation expense [1]	0.3	0.3	0.7	0.5
Income tax benefit	0.1	0.1	0.2	0.1

[1] The Company has not capitalized any share-based compensation cost. For the third quarter of 2009, the estimated forfeiture rates were 41.0% for restricted stock awards, 5.9% for restricted stock units, and 10.3% for performance shares.

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

September 30, 2009			Outstanding & Exercisable	
Year of grant	Range of exercise prices	Number of options	Weighted-average remaining contractual life	Weighted-average exercise price
2000	$ 14.74	46,000	0.6	$ 14.74
2001	17.96	65,000	1.6	17.96
2002	21.68	122,000	2.3	21.68
2003	20.49	141,500	3.0	20.49
	$ 14.74 21.68	374,500	2.2	$ 19.73

As of December 31, 2008, NQSOs outstanding totaled 375,500 (representing the same number of underlying shares), with a weighted-average exercise price of $19.73. As of September 30, 2009, all NQSO s outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $0.5 million.

NQSO activity and statistics are summarized as follows:

	Three months ended September 30		Nine months ended September 30	
($ in thousands, except prices)	2009	2008	2009	2008
Shares granted/forfeited/vested				
Aggregate fair value of vested shares				
Shares expired		8,000	1,000	8,000
Weighted-average price of shares expired		$ 19.23	$ 17.61	$ 19.23
Shares exercised		6,000		218,300
Weighted-average exercise price		$ 20.49		$ 19.64
Cash received from exercise		$ 123		$ 4,287
Intrinsic value of shares exercised [1]		$ 31		$ 2,217
Tax benefit (expense) realized for the deduction of exercises		$ (67)		$ 784
Dividend equivalent shares distributed under Section 409A				6,125
Weighted-average Section 409A distribution price				$ 22.38
Intrinsic value of shares distributed under Section 409A				$ 137
Tax benefit realized for Section 409A distributions				$ 53

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

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

September 30, 2009			Outstanding and 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	3.5	$ 26.02
2005	26.18	330,000	4.0	26.18

	$ 26.02	26.18	480,000	3.9	$	26.13

As of December 31, 2008, the shares underlying SARs outstanding totaled 791,000, with a weighted-average exercise price of $26.12. As of September 30, 2009, all SARS outstanding were exercisable and had no intrinsic value.

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SARs activity and statistics are summarized as follows:

($ in thousands, except prices)	Three months ended September 30 2009	Three months ended September 30 2008	Nine months ended September 30 2009	Nine months ended September 30 2008
Shares granted				
Shares forfeited			6,000	30,000
Weighted-average price of shares forfeited			$ 26.18	$ 26.18
Shares expired			305,000	
Weighted-average price of shares expired			$ 26.10	
Shares vested		18,000	228,000	79,000
Aggregate fair value of vested shares		$ 107	$ 1,354	$ 436
Shares exercised		30,000		30,000
Weighted-average exercise price		$ 26.02		$ 26.02
Cash received from exercise				
Intrinsic value of shares exercised [1]		$ 117		$ 117
Tax benefit realized for the deduction of exercises		$ 45		$ 45
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			$ 43	
Tax benefit realized for Section 409A distributions			$ 17	

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

Section 409A modification. As a result of the changes enacted in Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), for the nine months ended September 30, 2009 and 2008 a total of 3,143 and 6,125 dividend equivalent shares, respectively, 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 2 1/2 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 are planned to be paid in March 2010. These are the last dividend equivalents intended to be paid in accordance with this Section 409A modified distribution.

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

	Three months ended September 30, 2009 Shares	(1)	2008 Shares	(1)	Nine months ended September 30, 2009 Shares	(1)	2008 Shares	(1)
Outstanding, beginning of period	134,000	$ 25.50	170,200	$ 25.52	160,500	$ 25.51	146,000	$ 25.82
Granted			2,000	$ 24.68			44,700	$ 24.70
Restrictions ended			(6,170)	$ 25.44	(3,851)	$ 24.52	(6,170)	$ 25.44
Forfeited	(4,000)	$ 25.36	(4,830)	$ 25.74	(26,649)	$ 25.68	(23,330)	$ 25.92
Outstanding, end of period	130,000	$ 25.50	161,200	$ 25.51	130,000	$ 25.50	161,200	$ 25.51

(1) 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 and nine months ended September 30, 2008, total restricted stock granted had a weighted-average grant-date fair value of $49,000 and $1.1 million. No restricted stock was granted in 2009. For the three and nine months ended September 30, 2009, total restricted stock vested had a fair value of nil and $94,000. For the three and nine months ended September 30, 2008, total restricted stock vested had a fair value of $157,000.

The tax benefits realized for the tax deductions related to restricted stock awards was $0.1 million for the first nine months of 2009 and 2008.

As of September 30, 2009, there was $1.1 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 2.0 years.

Restricted stock units. In February 2009, 70,500 restricted stock units (representing the same number of underlying shares) were granted with a weighted-average grant date fair value of $1.2 million (weighted-average grant date fair value of $16.99 per restricted stock unit). The grant date fair value of a restricted stock unit was the average price of HEI common stock on the date of grant.

As of September 30, 2009, there were 70,500 restricted stock units outstanding with a weighted-average grant-date fair value of $16.99 per restricted stock unit. For the three and nine months ended September 30, 2009, no restricted stock units were vested or forfeited. As of September 30, 2009, there was $1.0 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 3.4 years.

Performance shares. Under the 2009-2011 LTIP, performance awards, which provide for payment in shares of HEI common stock or cash based on achievement of certain financial goals and service conditions over a three-year performance period were granted on February 20, 2009 to certain key executives. The payout varies from 0% to 280% of the number of shares depending on achievement of the goals. Performance conditions require the achievement of stated goals for total return to shareholders (TRS) as a percentile to the Edison Electric Institute Index over the three-year period and return on average common equity (ROACE) targets.

Performance shares linked to TRS. In February 2009, 36,198 performance shares with the TRS condition (based on target performance levels) were granted with a weighted-average grant-date fair value of $0.5 million based on the weighted-average grant-date fair value per share of $13.08. The grant date fair value was determined using a Monte Carlo simulation model utilizing actual information for the common shares of HEI and its peers for the period from January 1, 2009 to the February 20, 2009 grant date and estimated future stock volatility and dividends of HEI and its peers. 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 3-year historical period. The following table summarizes the assumptions used to determine the fair value of the performance shares linked to TRS and the resulting fair value of performance shares granted:

Risk-free interest rate	1.30%
Expected life in years	3
Expected volatility	23.7%
Dividend yield	4.53%
Range of expected volatility for Peer Group	20.8% to 46.9%
Grant date fair value (per share)	$13.08

As of September 30, 2009, there were 36,198 performance shares linked to TRS outstanding (based on target performance levels), with a weighted-average grant date fair value of $13.08 per share. For the three and nine months ended September 30, 2009, no performance share awards linked to TRS were vested or forfeited. As of September 30, 2009, there was $0.3 million of total unrecognized compensation cost related to the nonvested performance shares linked to TRS. The cost is expected to be recognized over a weighted-average period of 2.3 years.

Performance shares linked to ROACE. In February 2009, 24,131 shares underlying the performance share awards with the ROACE condition (based on target performance levels) were granted with a weighted-average grant-date fair value of $0.3 million based on the weighted-average grant-date fair value per share of $13.34. The grant date fair value of a performance share linked to ROACE was the average price of HEI common stock on grant date less the present value of expected dividends to be paid over the performance period, discounted by the risk-free interest rate based on the U.S. Treasury yield at the date of grant.

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As of September 30, 2009, there were 24,131 performance shares linked to ROACE outstanding (based on target performance levels), with a weighted-average grant date fair value of $13.34 per share. For the three and nine months ended September 30, 2009, no performance shares linked to ROACE were vested or forfeited. As of September 30, 2009, there was $0.2 million of total unrecognized compensation cost related to the nonvested performance shares linked to ROACE. The cost is expected to be recognized over a weighted-average period of 2.3 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 nine months ended September 30, 2009 and 2008, the Company paid interest (net of amounts capitalized and including bank interest) to non-affiliates amounting to $75 million and $137 million, respectively.

For the nine months ended September 30, 2009 and 2008, the Company paid income taxes amounting to $14 million and $93 million, respectively. The significant decrease in taxes paid was due primarily to the differences in the taxes due with the extensions for tax years 2008 and 2007 and in the estimated tax payments due for the first three quarters of 2009 and the first three quarters of 2008. In 2007, taxable income was significantly larger in the fourth quarter when compared to the first three quarters, resulting in a larger portion of the 2007 taxes paid with the extension filed in the first quarter of 2008. Taxable income for 2008 was much larger in the first half versus the second half of the year, resulting in only a nominal amount due in the first quarter of 2009. This larger taxable income also resulted in disproportionately higher estimated tax payments for the first three quarters of 2008 versus the first three quarters of 2009.

Supplemental disclosures of noncash activities. Noncash increases in common stock for director and officer compensatory plans of the Company was $1.5 million for the nine months ended September 30, 2009 and 2008.

Under the HEI Dividend Reinvestment and Stock Purchase Plan (DRIP), common stock dividends reinvested by shareholders in HEI common stock in noncash transactions amounted to $11 million and $16 million for the first nine months of 2009 and 2008, respectively. HEI satisfied the requirements of the HEI DRIP and the Hawaiian Electric Industries Retirement Savings Plan (HEIRS) (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 issuing additional shares. Effective September 4, 2009, HEI resumed satisfying the requirements of the HEI DRIP, HEIRS and ASB 401(k) Plan through the issuance of new common stock.

9 Recent accounting pronouncements and interpretations

See Fair Value Measurements in Note 4.

Noncontrolling interests. In December 2007, the FASB issued a standard that requires the recognition of a noncontrolling interest (i.e., a minority interest) as equity in the consolidated financial statements, separate from the parent s equity, and requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the income statement. Changes in the parent s ownership interest that leave control intact are accounted for as capital transactions (i.e., as increases or decreases in ownership), a gain or loss will be recognized when a subsidiary is deconsolidated based on the fair value of the noncontrolling equity investment (not carrying amount), and entities must provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and of the noncontrolling owners. The Company adopted the standard prospectively on January 1, 2009, except for the presentation and disclosure requirements which must be applied retrospectively. Thus, beginning in the first quarter of 2009, Preferred stock of subsidiaries not subject to mandatory redemption is presented as a separate component of Stockholders equity rather than as Minority interests in the mezzanine section between liabilities and equity on the balance sheet, dividends on preferred stock of subsidiaries is deducted from net income to arrive at net income for common stock on the income statement, and a column for Preferred stock of subsidiaries not subject to mandatory redemption has been added to the statement of changes in stockholders equity.

Participating securities. In June 2008, the FASB issued a standard under which unvested share-based-payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and therefore should be included in computing earnings per share using the two-class method. The Company adopted this standard in the first quarter of 2009 retrospectively and determined that restricted stock award grants were participating securities. The impact of adoption on the Company s financial statements was not material.

Fair value measurements and impairments. In April 2009, the FASB issued three standards providing additional application guidance and enhancing disclosures regarding fair value measurements and impairments of securities.

The first standard relates to determining fair values when there is no active market or where the price inputs being used represent distressed sales. It provides guidelines for making fair value measurements more consistent with the principles presented in an earlier standard by reaffirming that the objective of fair value measurement is to reflect how much an asset would be sold for in an orderly transaction (as opposed to a distressed or forced transaction) at the date of the financial statements under current market conditions. Specifically, it reaffirms the need to use judgment in determining fair values when markets have become inactive.

The second standard relates to fair value disclosures for any financial instruments that are not currently reflected on the balance sheet of companies at fair value. Prior to issuance of this standard, fair values for these assets and liabilities were only disclosed annually. This standard now requires these disclosures on a quarterly basis, providing qualitative and quantitative information about fair value estimates for financial instruments not measured on the balance sheet at fair value. See Note 10.

The third standard provides greater consistency to the timing of impairment recognition and greater clarity to investors about the credit and noncredit components of impaired debt securities that are not expected to be sold. The measure of impairment in comprehensive income remains fair value. This standard also requires increased and more timely disclosures regarding expected cash flows, credit losses and an aging of securities with unrealized losses.

The Company adopted the standards in the second quarter of 2009 and provided additional disclosures regarding fair value measurements and OTTIs. In the fourth quarter of 2008 the Company determined the impairment on two private-issue mortgage-related securities to be other-than-temporary, adjusted the carrying values to market value, and recognized a noncash impairment charge of $4.7 million, net of income tax, in the fourth quarter of 2008. Upon adoption of the standards, the Company reclassified $3.8 million of the previously recognized impairment to accumulated other comprehensive income.

Subsequent events. In May 2009, the FASB established general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued, which provide: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The Company adopted the standards in the second quarter of 2009. See Note 11.

Variable interest entities. In June 2009, the FASB issued a standard that amends the guidance in ASC Topic 810 related to the consolidation of variable interest entities (VIEs). The standard eliminates exceptions to consolidating qualifying special-purpose entities (QSPEs), contains new criteria for determining the primary beneficiary, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. The Company will adopt this standard in the first quarter of 2010 and has not yet fully determined the impact of adoption. HECO has determined that, under the new standard, it will need to consolidate HECO Capital Trust III from the first quarter of 2010, but the consolidation is not expected to have a significant impact on the Company s or HECO s consolidated financial statements.

FASB Codification. In June 2009, the FASB issued a standard that establishes the FASB Accounting Standards Codification™ as the single source of authoritative U.S. generally accepted accounting principles (GAAP) recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. The Company adopted this standard in the third quarter of 2009 and has eliminated citations for previous standards (other than SEC citations) in this Form 10-Q.

Measuring liabilities at fair value. Accounting Standards Update No. 2009 05 amends Subtopic 820-10, Fair Value Measurements and Disclosures Overall, and provides clarification that (1) in circumstances in which a quoted price in an active market for an identical liability is not available, a reporting entity is required to measure fair value using specified techniques, (2) when estimating the fair value of a liability, a reporting entity is not required to include a separate input, or adjustment to other inputs, relating to the existence of a restriction that prevents the transfer of the liability, and (3) both a quoted price in an active market for the identical liability at the measurement date and the quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required are Level 1 fair value measurements. The Company will adopt this guidance in the fourth quarter of 2009 and believes the adoption will not have impact on its financial condition, results of operations and 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.

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

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

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

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 and unused lines of credit was estimated based on the primary market prices of new commitments and new lines of credit. The change in current primary market prices provided the estimate of the fair value of these commitments and unused lines of credit. The fair values of other off-balance sheet financial instruments (letters of credit) were estimated based on the fees currently charged to enter into similar agreements, taking into account the remaining terms of the agreements. Fair value of HECO-obligated preferred securities of trust subsidiaries was based on quoted market prices.

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

	September 30, 2009		December 31, 2008	
(in thousands)	Carrying or notional amount	Estimated fair value	Carrying or notional amount	Estimated fair value
Financial assets				
Cash and equivalents	$ 257,331	$ 257,331	$ 182,903	$ 182,903
Federal funds sold	1,708	1,708	532	532
Available-for-sale investment and mortgage-related securities	623,104	623,104	657,717	657,717
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764	97,764	97,764
Loans receivable, net	3,758,898	3,853,514	4,206,492	4,322,153
Financial liabilities				
Deposit liabilities	4,047,940	4,057,851	4,180,175	4,197,429
Other bank borrowings	367,884	383,273	680,973	701,998
Long-term debt	1,364,784	1,324,095	1,211,501	949,170
Off-balance sheet items				
HECO-obligated preferred securities of trust subsidiary	50,000	47,440	50,000	40,420

As of September 30, 2009 and December 31, 2008, loan commitments and unused lines and letters of credit had notional amounts of $1.2 billion and their estimated fair value on such dates was $0.3 million and $0.8 million, respectively. As of September 30, 2009 and December 31, 2008, loans serviced for others had notional amounts of $531.3 million and $307.6 million and the estimated fair value of the servicing rights for such loans was $4.8 million and $2.6 million, respectively.

11 Subsequent events

The Company has evaluated subsequent events through November 2, 2009, the date the financial statements were issued.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

(in thousands, except ratio of earnings to fixed charges)	Three months ended September 30 2009	Three months ended September 30 2008	Nine months ended September 30 2009	Nine months ended September 30 2008
Operating revenues	**$ 546,502**	**$ 826,124**	**$ 1,453,623**	**$ 2,135,265**
Operating expenses				
Fuel oil	186,719	377,157	463,893	900,455
Purchased power	134,447	202,125	364,120	530,146
Other operation	61,173	61,599	186,751	176,600
Maintenance	25,968	25,174	81,562	72,777
Depreciation	35,557	35,419	108,406	106,254
Taxes, other than income taxes	50,031	74,201	137,741	194,058
Income taxes	15,957	15,035	33,228	47,507
	509,852	790,710	1,375,701	2,027,797
Operating income	**36,650**	**35,414**	**77,922**	**107,468**
Other income				
Allowance for equity funds used during construction	2,628	2,426	10,353	6,432
Other, net	1,657	1,486	6,493	3,693
	4,285	3,912	16,846	10,125
Interest and other charges				
Interest on long-term debt	13,601	11,879	37,458	35,413
Amortization of net bond premium and expense	735	632	2,092	1,902
Other interest charges	705	1,352	2,048	3,397
Allowance for borrowed funds used during construction	(1,118)	(967)	(4,467)	(2,564)
	13,923	12,896	37,131	38,148
Net income	**27,012**	**26,430**	**57,637**	**79,445**
Less net income attributable to noncontrolling interest - preferred stock of subsidiaries	228	228	686	686
Net income attributable to HECO	**26,784**	**26,202**	**56,951**	**78,759**
Preferred stock dividends of HECO	270	270	810	810
Net income for common stock	**$ 26,514**	**$ 25,932**	**$ 56,141**	**$ 77,949**
Ratio of earnings to fixed charges (SEC method)			2.92	3.83

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)	September 30, 2009	December 31, 2008
Assets		
Utility plant, at cost		
Land	$ 51,401	$ 42,541
Plant and equipment	4,612,113	4,277,499
Less accumulated depreciation	(1,822,860)	(1,741,453)
Construction in progress	155,465	266,628
Net utility plant	2,996,119	2,845,215
Current assets		
Cash and equivalents	6,486	6,901
Customer accounts receivable, net	133,709	166,422
Accrued unbilled revenues, net	92,361	106,544
Other accounts receivable, net	8,208	7,918
Fuel oil stock, at average cost	67,889	77,715
Materials and supplies, at average cost	36,357	34,532
Prepayments and other	13,879	12,626
Total current assets	358,889	412,658
Other long-term assets		
Regulatory assets	535,287	530,619
Unamortized debt expense	15,184	14,503
Other	69,400	53,114
Total other long-term assets	619,871	598,236
	$ 3,974,879	$ 3,856,109
Capitalization and liabilities		
Capitalization		
Common stock, $6 2/3 par value, authorized 50,000 shares; outstanding 12,806 shares	$ 85,387	$ 85,387
Premium on capital stock	299,207	299,214
Retained earnings	825,975	802,590
Accumulated other comprehensive income, net of income taxes	1,824	1,651
Common stock equity	1,212,393	1,188,842
Cumulative preferred stock not subject to mandatory redemption	22,293	22,293
Noncontrolling interest cumulative preferred stock of subsidiaries not subject to mandatory redemption	12,000	12,000
Stockholders equity	1,246,686	1,223,135
Long-term debt, net	1,057,784	904,501
Total capitalization	2,304,470	2,127,636
Current liabilities		
Short-term borrowings affiliate	10,700	41,550

Accounts payable	118,042	122,994
Interest and preferred dividends payable	21,096	15,397
Taxes accrued	155,211	220,046
Other	48,389	55,268
Total current liabilities	353,438	455,255
Deferred credits and other liabilities		
Deferred income taxes	178,336	166,310
Regulatory liabilities	282,239	288,602
Unamortized tax credits	57,885	58,796
Retirement benefits liability	399,539	392,845
Other	83,517	54,949
Total deferred credits and other liabilities	1,001,516	961,502
Contributions in aid of construction	315,455	311,716
	$ 3,974,879	$ 3,856,109

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity (unaudited)

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Premium on capital stock	Retained earnings	Accumulated other comprehensive income	Cumulative preferred stock	Noncontrolling interest: cumulative preferred stock of subsidiaries	Total
Balance, December 31, 2008	**12,806**	**$ 85,387**	**$ 299,214**	**$ 802,590**	**$ 1,651**	**$ 22,293**	**$ 12,000**	**$ 1,223,135**
Comprehensive income:								
Net income				56,141		810	686	57,637
Retirement benefit plans:								
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $5,101					8,008			8,008
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $4,990					(7,835)			(7,835)
Comprehensive income				56,141	173	810	686	57,810
Capital stock expense			(7)					(7)
Common stock dividends				(32,756)				(32,756)
Preferred stock dividends						(810)	(686)	(1,496)
Balance, September 30, 2009	**12,806**	**$ 85,387**	**$ 299,207**	**$ 825,975**	**$ 1,824**	**$ 22,293**	**$ 12,000**	**$ 1,246,686**
Balance, December 31, 2007	**12,806**	**$ 85,387**	**$ 299,214**	**$ 724,704**	**$ 1,157**	**$ 22,293**	**$ 12,000**	**$ 1,144,755**
Comprehensive income:								
Net income				77,949		810	686	79,445
Retirement benefit plans:								
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $2,611					4,099			4,099
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $2,501					(3,928)			(3,928)
Comprehensive income				77,949	171	810	686	79,616
Common stock dividends				(14,088)				(14,088)
Preferred stock dividends						(810)	(686)	(1,496)
Balance, September 30, 2008	**12,806**	**$ 85,387**	**$ 299,214**	**$ 788,565**	**$ 1,328**	**$ 22,293**	**$ 12,000**	**$ 1,208,787**

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Cash Flows (unaudited)

Nine months ended September 30 (in thousands)	2009	2008
Cash flows from operating activities		
Net income	$ 57,637	$ 79,445
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	108,406	106,254
Other amortization	7,702	6,426
Changes in deferred income taxes	12,532	6,588
Changes in tax credits, net	(501)	1,503
Allowance for equity funds used during construction	(10,353)	(6,432)
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	32,423	(59,551)
Decrease (increase) in accrued unbilled revenues	14,183	(23,394)
Decrease (increase) in fuel oil stock	9,826	(79,693)
Increase in materials and supplies	(1,825)	(3,435)
Increase in regulatory assets	(13,829)	(28)
Increase (decrease) in accounts payable	(4,952)	46,324
Change in prepaid and accrued income and utility revenue taxes	(62,388)	(7,969)
Changes in other assets and liabilities	3,360	(5,386)
Net cash provided by operating activities	**152,221**	**60,652**
Cash flows from investing activities		
Capital expenditures	(237,664)	(170,321)
Contributions in aid of construction	7,472	12,266
Other	340	749
Net cash used in investing activities	**(229,852)**	**(157,306)**
Cash flows from financing activities		
Common stock dividends	(32,756)	(14,088)
Preferred stock dividends	(1,496)	(1,496)
Proceeds from issuance of long-term debt	153,186	18,707
Net increase (decrease) in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	(30,850)	112,204
Decrease in cash overdraft	(9,847)	(8,582)
Other	(1,021)	
Net cash provided by financing activities	**77,216**	**106,745**
Net increase (decrease) in cash and equivalents	(415)	10,091
Cash and equivalents, beginning of period	6,901	4,678
Cash and equivalents, end of period	**$ 6,486**	**$ 14,769**

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 should be read in conjunction with the audited consolidated financial statements and the notes thereto filed in HECO Exhibit 99.2 to HECO s Form 8-K dated June 9, 2009 and the unaudited consolidated financial statements and the notes thereto in HECO s Quarterly Reports on SEC Form 10-Q for the quarters ended March 31, 2009 and June 30, 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 September 30, 2009 and December 31, 2008 and the results of their operations for the three and nine months ended September 30, 2009 and 2008 and their cash flows for the nine months ended September 30, 2009 and 2008. All such adjustments are of a normal recurring nature, unless otherwise disclosed in this Form 10-Q or other referenced material. Results of operations for interim periods are not necessarily indicative of results for the full year. When required, certain reclassifications are made to the prior period s consolidated financial statements to conform to the current presentation.

2 Unconsolidated variable interest entities

HECO Capital Trust III. HECO Capital Trust III (Trust III) was created and exists for the exclusive purposes of (i) issuing in March 2004 2,000,000 6.50% Cumulative Quarterly Income Preferred Securities, Series 2004 (2004 Trust Preferred Securities) ($50 million aggregate liquidation preference) to the public and trust common securities ($1.5 million aggregate liquidation preference) to HECO, (ii) investing the proceeds of these trust securities in 2004 Debentures issued by HECO in the principal amount of $31.5 million and issued by each of Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO) in the respective principal amounts of $10 million, (iii) making distributions on the trust securities and (iv) engaging in only those other activities necessary or incidental thereto. The 2004 Trust Preferred Securities are mandatorily redeemable at the maturity of the underlying debt on March 18, 2034, which maturity may be extended to no later than March 18, 2053; and are 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 variable interest entities (VIEs). Trust III s balance sheets as of September 30, 2009 and December 31, 2008 each consisted of $51.5 million of 2004 Debentures; $50.0 million of 2004 Trust Preferred Securities; and $1.5 million of trust common securities. Trust III s income statements for the nine months ended September 30, 2009 and 2008 each consisted of $2.5 million of interest income received from the 2004 Debentures; $2.4 million of distributions to holders of the Trust Preferred Securities; and $0.1 million of common dividends on the trust common securities to HECO. So long as the 2004 Trust Preferred Securities are outstanding, HECO is not entitled to receive any funds from Trust III other than pro rata distributions, subject to certain subordination provisions, on the trust common securities. In the event of a default by HECO in the performance of its obligations under the 2004 Debentures or under its Guarantees, or in the event HECO, HELCO or MECO elect to defer payment of interest on any of their respective 2004 Debentures, then

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

From the first quarter of 2010, HECO has determined that it will need to consolidate HECO Capital Trust III (see Variable interest entities in Note 9 of HEI s Notes to Consolidated Financial Statements).

Purchase power agreements. As of September 30, 2009, HECO and its subsidiaries had six PPAs for a total of 540 megawatts (MW) of firm capacity, and other PPAs with smaller IPPs and Schedule Q providers (i.e., customers with cogeneration and/or small power production facilities with a capacity of 100 KWHs or less who buy power from or sell power to the utilities) that supplied as-available energy. Approximately 91% of the 540 MW of firm capacity is under PPAs, entered into before December 31, 2003, with AES Hawaii, Inc. (AES Hawaii), Kalaeloa Partners, L.P. (Kalaeloa), Hamakua Energy Partners, L.P. (HEP) and HPOWER. Purchases from all IPPs for the nine months ended September 30, 2009 totaled $364 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $104 million, $127 million, $44 million and $31 million, respectively. The primary business activities of these IPPs are the generation and sale of power to HECO and its subsidiaries (and municipal waste disposal in the case of HPOWER). Current financial information about the size, including total assets and revenues, for many of these IPPs is not publicly available.

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, after making an exhaustive effort, the necessary information.

HECO reviewed its significant PPAs and determined in 2004 that the IPPs at that time had no contractual obligation to provide such information. In March 2004, HECO and its subsidiaries sent letters to all of their IPPs, except the Schedule Q providers, requesting the information that they need to determine the applicability of accounting standards for VIEs to the respective IPP, and subsequently contacted most of the IPPs to explain and repeat its request for information. (HECO and its subsidiaries excluded their Schedule Q providers because their variable interest in the provider would not be significant to the utilities and they did not participate significantly in the design of the provider.) Some of the IPPs provided sufficient information for HECO to determine that the IPP was not a VIE, or was either a business or governmental organization (e.g., HPOWER), and thus excluded from the scope of accounting standards for VIEs. Other IPPs, including the three largest, declined to provide the information necessary for HECO to determine the applicability of accounting standards for VIEs.

Since 2004, HECO has continued its efforts to obtain from the IPPs the information necessary to make the determinations required under accounting standards for VIEs. In each year from 2005 to 2009, HECO and its subsidiaries sent letters to the identified IPPs, requesting the required information. All of these IPPs declined to provide the necessary information, except that Kalaeloa provided the information pursuant to the amendments to its PPA (see below) and an entity owning a wind farm provided information as required under the PPA. Management has concluded that the consolidation of two entities owning wind farms was not required as HELCO and MECO do not have variable interests in the entities because the PPAs do not require them to absorb any variability of the entities.

If the requested information is ultimately received from the other IPPs, a possible outcome of future analysis is the consolidation of one or more of such IPPs in HECO s consolidated financial statements. The consolidation of any significant IPP could have a material effect on HECO s consolidated financial statements, including the recognition of a significant amount of assets and liabilities and, if such a consolidated IPP were operating at a loss and had insufficient equity, the potential recognition of such losses. If HECO and its subsidiaries determine they are required to consolidate the financial statements of such an IPP and the consolidation has a material effect, HECO and its subsidiaries would retrospectively apply accounting standards for VIEs.

Kalaeloa Partners, L.P. In October 1988, HECO entered into a PPA with Kalaeloa, subsequently approved by the PUC, which provided that HECO would purchase 180 MW of firm capacity for a period of 25 years beginning in May 1991. In October 2004, HECO and Kalaeloa entered into amendments to the PPA, subsequently approved by the PUC, which together effectively increased the firm capacity from 180 MW to 208 MW. The energy payments that HECO makes to Kalaeloa include: 1) a fuel component, with a fuel price adjustment based on the cost of low sulfur fuel oil, 2) a fuel additives cost component, and 3) a non-fuel component, with an adjustment based on changes in the Gross National Product Implicit Price Deflator. The capacity payments that HECO makes to Kalaeloa are fixed in accordance with the PPA. Kalaeloa also has a steam delivery cogeneration contract with another customer, the term of which coincides with the PPA. The facility has been certified by the Federal Energy Regulatory Commission as a Qualifying Facility under the Public Utility Regulatory Policies Act of 1978.

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

3 Revenue taxes

HECO and its subsidiaries operating revenues include amounts for various revenue taxes. Revenue taxes are generally recorded as an expense in the period the related revenues are recognized. However, HECO and its subsidiaries revenue tax payments to the taxing authorities are based on the prior year s revenues. For the nine months ended September 30, 2009 and 2008, HECO and its subsidiaries included approximately $130 million and $187 million, respectively, of revenue taxes in operating revenues and in taxes, other than income taxes expense.

4 Retirement benefits

Defined benefit plans. For the first nine months of 2009, HECO and its subsidiaries contributed $19.9 million to their retirement benefit plans, compared to $9.3 million in the first nine months of 2008. HECO and its subsidiaries current estimate of contributions to their retirement benefit plans in 2009 is $24 million, compared to contributions of $14 million in 2008. In addition, HECO and its subsidiaries expect to pay directly $0.7 million of benefits in 2009, compared to $0.1 million paid in 2008.

For the first nine months of 2009, HECO and its subsidiaries defined benefit retirement plans assets generated a return, net of investment management fees, of 21.4%. The market value of the defined benefit retirement plan s assets as of September 30, 2009 was $768 million compared to $655 million at December 31, 2008, an increase of approximately $113 million.

The components of net periodic benefit cost were as follows:

	Three months ended September 30				Nine months ended September 30			
	Pension benefits		Other benefits		Pension benefits		Other benefits	
(in thousands)	**2009**	**2008**	**2009**	**2008**	**2009**	**2008**	**2009**	**2008**
Service cost	$ 6,205	$ 6,863	$ 1,385	$ 1,179	$ 18,372	$ 20,039	$ 3,549	$ 3,464
Interest cost	14,005	13,528	2,594	2,617	42,089	40,446	8,114	8,081
Expected return on plan assets	(12,735)	(16,333)	(2,204)	(2,698)	(38,101)	(48,861)	(6,565)	(8,090)
Amortization of unrecognized transition obligation			259	783			1,824	2,348
Amortization of prior service credit	(190)	(191)	(37)		(558)	(572)	(37)	
Recognized actuarial loss	3,677	1,646	79		11,021	4,935	296	
Net periodic benefit cost	10,962	5,513	2,076	1,881	32,823	15,987	7,181	5,803
Impact of PUC D&Os	(1,776)	1,327	(270)	308	(9,974)	4,531	(1,002)	731
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 9,186	$ 6,840	$ 1,806	$ 2,189	$ 22,849	$ 20,518	$ 6,179	$ 6,534

HECO and its subsidiaries recorded retirement benefits expense of $22 million and $20 million in the first nine months of 2009 and 2008, respectively. The electric utilities charged a portion of the net periodic benefit costs to plant.

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In the third quarter 2009, 1) the utilities 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 utilities cost for postretirement benefits other than pensions (OPEB) has been adjusted to reflect the negative 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 negative amendment credit is amortized.

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 HELCO s 2007 interim decision on its 2006 test year rate case, and in HECO s and MECO s 2007 interim decisions on their 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 a rate case. Under the utilities tracking mechanisms, any actual costs determined under SFAS Nos. 87 and 106, as amended, that are over/under amounts allowed in rates are charged/credited to a regulatory asset/liability. The regulatory asset/liability for each utility will 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 $1.4 million in 2008) determined under SFAS Nos. 87 and 106, as amended, will be recovered.

Under the tracking mechanisms, amounts that would otherwise be recorded in AOCI pursuant to SFAS No. 158 (excluding amounts for executive life and nonqualified pension plans), which amounts include the prepaid pension asset prior to the adoption of SFAS No. 158, net of taxes, as well as other pension and OPEB charges related to SFAS No. 158, 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 HELCO s 2007 interim decision on its 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 prior to the adoption of SFAS No. 158 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.

In HECO s and MECO s 2007 interim decisions on their 2007 test year rate cases (and in HECO s final decision on its 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 prior to the adoption of SFAS No. 158), 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 contribution limitations on deductible 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 September 30, 2009, MECO did not have any remaining pension asset, and HECO s pension asset had been reduced to $15 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.

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5 Commitments and contingencies

Hawaii Clean Energy Initiative. In January 2008, the State of Hawaii and the U.S. Department of Energy (DOE) signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative (HCEI). The stated purpose of the HCEI is to establish a long-term partnership between the State of Hawaii and the DOE that will result in a fundamental and sustained transformation in the way in which energy resources are planned and used in the State. HECO has been working with the State, the DOE and other stakeholders to align the utility s energy plans with the State s plans.

On October 20, 2008, 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 State of Hawaii 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). The Energy Agreement provides that the parties pursue a wide range of actions with the purpose of decreasing the State of Hawaii 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 most directly affecting HECO and its subsidiaries are the following:

<u>Renewable energy and energy efficiency goals</u>. 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 promote the transportation goals, the Energy Agreement provides for the parties to evaluate and implement incentives to encourage adoption of electric vehicles, and to lead by example by acquiring hybrid or electric-only vehicles for government and utility fleets.

To help achieve the HCEI goals, the Energy Agreement further provides for the parties to seek amendment to the Hawaii Renewable Portfolio Standards (RPS) law (law which establishes renewable energy requirements for electric utilities that sell electricity for consumption in the State) to increase the current requirements from 20% to 25% by the year 2020, and to add a further RPS goal of 40% by the year 2030. The revised RPS law would also require that after 2014 the RPS goal be met solely with renewable energy generation versus including energy savings from energy efficiency measures. However, energy savings from energy efficiency measures would be counted toward the achievement of the overall HCEI 70% goal. These changes to the RPS law were subsequently enacted when Act 155 was passed by the Hawaii legislature and signed into law by the Governor in 2009.

In December 2007, the PUC issued a D&O approving a stipulated RPS framework to govern electric utilities compliance with the RPS law. In a follow up order in December 2008, the PUC approved a penalty of $20 for every MWh that an electric utility is deficient under Hawaii s RPS law. The PUC noted, however, that 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, as described in the RPS law and in the RPS Framework. In addition, the PUC ordered that: (1) any penalties assessed against HECO and its subsidiaries for failure to meet the RPS will go into the Public Benefits Fund (PBF) account used to support energy efficiency and DSM programs and services, unless otherwise directed; and (2) the utilities will be prohibited from recovering any RPS penalty costs through rates.

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To further encourage the contributions of energy efficiency to the overall HCEI goal, the Energy Agreement provides for the parties to seek establishment of energy efficiency goals through an Energy Efficiency Portfolio Standard. Such an Energy Efficiency Portfolio Standard was enacted as part of Act 155, which provided that the PUC shall establish the standards designed to achieve a reduction of 4,300 gigawatthours of electricity use statewide by 2030. The law also provides that the PUC shall establish interim goals for electricity use reduction to be achieved by 2015, 2020, and 2025, and may revise the 2030 standard by rule or order to maximize cost-effective, energy-efficiency programs and technologies and may establish incentives and penalties.

Public benefits fund (PBF). To help fund energy efficiency programs, incentives, program administration, customer education, and other related program costs, as expended by the third-party administrator for the energy efficiency programs or by program contractors, which may include the utilities, the Energy Agreement provides that the parties will request that the PUC establish a PBF that is funded by collecting 1% of the utilities revenues in years one and two after implementation of a PBF; 1.5% in years three and four; and 2% thereafter. In December 2008, the PUC issued an order directing the utilities to collect revenue equal to 1% of the projected total electric revenue of the utilities, of which 60% shall be collected via the DSM surcharge and 40% via the PBF surcharge. Beginning January 1, 2009, the 1% is being assessed on customers of HECO and its subsidiaries.

Clean Energy Infrastructure Surcharge (CEIS). The Energy Agreement provides for the establishment of a CEIS. The CEIS, which will need to be approved by the PUC, is to be designed to expedite cost recovery for a variety of infrastructure that supports greater use of renewable energy or grid efficiency within the utility systems (such as advanced metering, energy storage, interconnections and interfaces). The Energy Agreement provides that the surcharge should be available to recover costs that would normally be expensed in the year incurred and capital costs (including the allowed return on investment, AFUDC, depreciation, applicable taxes and other approved costs), and could also be used to recover costs stranded by clean energy initiatives. On November 28, 2008, HECO and the Consumer Advocate filed a joint letter informing the PUC that the pending Renewable Energy Infrastructure Program (REIP) Surcharge satisfies the Energy Agreement provision for an implementation procedure for the CEIS recovery mechanism and that no further regulatory action on the CEIS is necessary, and reaffirming that the REIP Surcharge is ready for PUC decision-making.

Renewable energy projects. HECO and its subsidiaries will continue to negotiate with developers of currently proposed projects (identified in the Energy Agreement) to integrate 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 of Hawaii, 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 technical resources such as the U.S. Department of Energy national laboratories, HECO, along with the other 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 for the Oahu grid 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.

With respect to the undersea transmission cable system, 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. In the event federal funding is unavailable, the State will employ its best effort to fund the undersea cable system through a prudent combination of taxpayer and ratepayer sources. There is no obligation on the part of HECO to fund any of the cost of the undersea cable. However, in the event HECO funds any part of the cost to develop the undersea cable system and assumes any ownership of the cable system, all reasonably incurred capital costs and expenses are intended to be recoverable through the CEIS.

Feed-in tariff (FIT). As another method of accelerating the acquisition of renewable energy by the utilities, the Energy Agreement includes support of the parties for the development of a FIT system with standardized purchase prices for renewable energy. The PUC was requested to conclude an investigative proceeding by March 2009 to determine the best design for a FIT that supports the HCEI goals, considering such factors as categories of renewables, size or locational limits for projects qualifying for the FIT, what annual limits should apply to the amount of renewables allowed to utilize the FIT, what factors to incorporate into the prices set for FIT payments, and other terms and conditions. Based on these understandings, the Energy Agreement required that the parties request the PUC to suspend the pending intra-governmental wheeling and avoided cost (Schedule Q) dockets for a period of 12 months. 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. On December 11, 2008, the PUC issued a scoping paper prepared by its consultant that specified certain issues and questions for the parties to address and for the utilities and the Consumer Advocate to consider in a joint FIT proposal. On December 23, 2008, the utilities and the Consumer Advocate filed a joint proposal on FITs that called for the establishment of simple, streamlined and broad standard payment rates, which can be offered to as many renewable technologies as feasible. It proposed that the initial FIT be focused on photovoltaics (PV), concentrated solar power, in-line hydropower and wind, with individual project sizes targeted to provide a greater likelihood of more straightforward interconnection, project implementation and use of standardized energy rates and power purchase contracting. The FIT would be regularly reviewed to update tariff pricing to applicable technologies, project sizes and annual targets. A FIT update would be conducted for all islands in the utilities service territory not later than two years after initial implementation of the FIT and every three years thereafter.

The FIT joint proposal also recommended that no applications for new net energy metering contracts be accepted once the FIT is formally made available to customers (although existing net energy metering systems under contract would be grandfathered), and no applications for new Schedule Q contracts would be accepted once a FIT is formally made available for the resource type. Schedule Q would continue as an option for qualifying projects of 100 kW and less for which a FIT is not available.

In September 2009, the PUC issued a 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, concentrated solar power, onshore wind, and in-line hydropower projects up to 5 MW depending on technology and location. There will also be a baseline FIT rate to encourage other renewable energy technologies. Net energy metering, competitive bidding, negotiated PPAs, Schedule Q, and avoided cost offerings will continue to exist as additional and complementary mechanisms to provide multiple avenues for the procurement of renewable energy. 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, size, and interconnection costs; and will be levelized. The FIT program will be reexamined two years after it first becomes effective and every three years thereafter. The D&O directs the utilities to develop reliability standards for each company, and states that the PUC will direct: (1) the companies to establish FITs in their respective service territories; (2) the companies to file status reports on the progress of the FIT program; and (3) the companies collaborate with the other parties to craft queuing and interconnection procedures that will minimize delays associated with numerous potential FIT projects and the various interconnection studies they could require. On October 12, 2009, the utilities and Consumer Advocate filed a proposed order setting forth a procedural schedule for the docket. The State of Hawaii Department of Business, Economic Development and Tourism (DBEDT) and the other parties also filed a proposed procedural schedule.

Net energy metering (NEM). The Energy Agreement also provides that system-wide caps on NEM should be removed. 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 net energy metering system caps from 1% to 3% of system peak demand (among other changes) and the PUC approved the proposed caps. The PUC directed the parties to file a proposed plan to address the provisions regarding NEM in the Energy Agreement, which plans were filed in August 2009. The utilities plan provides for HECO to develop per-circuit interconnection limitations for all grid-connected distributed generation, of which NEM is one category, by December 31, 2009. In the case of HELCO and possibly MECO, the plan noted that because of their increasing renewable energy penetration, the earlier HCEI agreement to remove system-wide caps must be further reviewed in order to ensure circuit reliability, safety and grid stability. The timeframe for completing this assessment of the implications of removing the system-wide caps is November/December 2009.

Using biofuels. The Energy Agreement includes support of the parties for 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. The parties agree that use of biofuels in the utilities generating units, particularly biofuels from local sources, can contribute to achieving RPS requirements and decreasing greenhouse gas emissions, while avoiding 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 cost of the biodiesel fuel purchased under such contracts in their respective ECACs and, in the case of HECO, the commitment of funds in excess of $2.5 million (estimated at $5.2 million) for the purchase of capital equipment, in connection with proposed demonstration projects to test the use of biofuels to determine, in the case of HECO, the maximum blend of biofuels with low sulfur fuels for use in its steam electric generation units and, in the case of MECO, biodiesel s potential as a primary fuel in utility scale diesel engines with the objective of evaluating the longer term effects biodiesel will have on efficiency, emissions, storage and handling, operations and other issues. In September 2009, the PUC denied the application of Life of the Land to intervene in the two proceedings, but allowed it to participate with respect to the issue of the environmental sustainability of palm oil base biodiesel. The PUC has approved procedural orders proposed by the utilities and Consumer Advocate in each docket.

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 agree that it is appropriate to adopt a regulatory rate-making model, which is subject to PUC approval, under which HECO, HELCO and MECO revenues would be decoupled from KWH sales. If approved by the PUC, the new regulatory model, which could be similar to the regulatory models currently used in California, would employ a revenue adjustment mechanism to track on an ongoing basis the differences between the amount of revenues allowed in the last rate case and (a) the current costs of providing electric service and (b) a reasonable return on and return of additional capital investment in the electric system. The utilities would also continue to use existing PUC-approved tracking mechanisms for pension and other post-retirement benefits. The utilities would also be allowed an automatic revenue adjustment mechanism to reflect changes in state or federal tax rates.

On October 24, 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In addition to the utilities and the Consumer Advocate, there are five other parties in the proceeding. The utilities and the Consumer Advocate filed a joint statement of position in March and May 2009. Panel hearings at the PUC were completed on July 1, 2009. Briefing by the parties was completed in September 2009.

In its 2009 test year rate case, HECO proposed to establish a revenue balancing account (RBA) to be effective upon the issuance of the interim D&O, but the PUC did not approve the proposal, pending the outcome of the decoupling proceeding. The Energy Agreement also contemplates that additional rate cases based on a 2009 test year will be filed by HELCO and MECO in order to provide their respective baselines for implementation of the new regulatory model, but HELCO and MECO were unable to file 2009 test year rate case applications. On July 17, 2009, MECO filed a Notice of Intent to file an application for a general rate case using a 2010 calendar test year on or after September 30, 2009 (but before January 1, 2010), and HELCO filed a Notice of Intent to file an application for a general rate case using a 2010 test year on or after November 25, 2009 (but before January 1, 2010).

Subsequently, MECO filed its general rate increase application on September 30, 2009, requesting approval of a revenue increase of 9.7%, or $28.2 million, over revenues at current rates.

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, including all capacity, operation and maintenance expenses and other non-energy payments.

In December 2008, HECO filed updates to its 2009 test year rate case. The updates 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.

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 and including, but not limited to: (a) promoting through specifically proposed steps greater use of solar energy through solar water heating, commercial and residential photovoltaic energy installations and concentrated solar power generation; (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 in 2009 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) including 10% of the energy purchased under FITs in each utility s respective rate base through January 2015; (g) delinking prices paid under all new renewable energy contracts from oil prices; and (h) exploring the possibility of establishing lifeline rates designed to provide a cap on rates for those who are unable to pay the full cost of electricity. The utilities proposed Lifeline Rate Program, submitted for approval at the end of April 2009 to the PUC, would provide a monthly bill credit to qualified, low-income customers. HECO and the Consumer Advocate are progressing through the information request process, as provided for in a stipulated procedural schedule filed in September 2009.

Interim increases. On April 4, 2007, the PUC issued an interim D&O in HELCO s 2006 test year rate case granting an annual increase of $24.6 million, or 7.58%, which was implemented on April 5, 2007.

On October 22, 2007, the PUC issued, and HECO immediately implemented, an interim D&O in HECO s 2007 test year rate case, granting an annual increase of $70 million, a 4.96% increase over rates effective at the time of the interim decision ($78 million over rates granted in the final decision in HECO s 2005 test year rate case).

On December 21, 2007, the PUC issued, and MECO immediately implemented, an interim D&O in MECO s 2007 test year rate case, granting an annual increase of $13 million, or a 3.7% increase.

On July 2, 2009, the PUC issued an interim D&O in HECO s 2009 test year rate case, which 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. HECO calculated the interim increase amount at $61.1 million annually, or a 4.7% increase, and submitted the information to the PUC on July 8, 2009. The PUC approved HECO s calculation and HECO implemented the interim increase on August 3, 2009.

As of September 30, 2009, HECO and its subsidiaries had recognized $237 million of revenues with respect to interim orders ($5 million related to interim orders regarding certain integrated resource planning costs and $232 million related to interim orders regarding general rate increase requests). Revenue amounts recorded pursuant to interim orders are subject to refund, with interest, if they exceed amounts allowed in a final order.

Energy cost adjustment clauses. Hawaii Act 162 (Act 162) was signed into law in June 2006 and requires that any automatic fuel rate adjustment clause requested by a public utility in an application filed with the PUC be designed, as determined in the PUC s discretion, to (1) fairly share the risk of fuel cost changes between the utility and its customers, (2) provide the utility with incentive to manage or lower its fuel costs and encourage greater use of renewable energy, (3) allow the utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through commercially reasonable means, such as through fuel hedging contracts, (4) preserve the utility s financial integrity, and (5) minimize the utility s need to apply for frequent general rate increases for fuel cost changes. While the PUC already had reviewed the automatic fuel adjustment clauses in rate cases, Act 162 requires that these five specific factors be addressed in the record.

In May 2008, the PUC issued a final D&O in HECO s 2005 test year rate case in which the PUC agreed with the parties stipulation in the proceeding that it would not require the parties in the proceeding to submit a stipulated procedural schedule to address the Act 162 factors in the 2005 test year rate case proceeding, and stated it expected HECO and HELCO to develop information relating to the Act 162 factors for examination during their next rate case proceedings.

In the HELCO 2006 test year rate case, the filed testimony of the Consumer Advocate s consultant concluded that HELCO s ECAC provides a fair sharing of the risks of fuel cost changes between HELCO and its ratepayers in a manner that preserves the financial integrity of HELCO without the need for frequent rate filings. In April and December 2007, the PUC issued interim D&Os in the HELCO 2006 and MECO 2007 test year rate cases that reflected for purposes of the interim order the continuation of their ECACs, consistent with agreements reached between the Consumer Advocate and HELCO and MECO, respectively. The Consumer Advocate and MECO agreed that no further changes are required to MECO s ECAC in order to comply with the requirements of Act 162.

In September 2007, HECO, the Consumer Advocate and the federal Department of Defense (DOD) agreed that the ECAC should continue in its present form for purposes of an interim rate increase in the HECO 2007 test year rate case and stated that they are continuing discussions with respect to the final design of the ECAC to be proposed for approval in the final D&O. In October 2007, the PUC issued an interim D&O, which reflected the continuation of HECO s ECAC for purposes of the interim increase.

Management cannot predict the ultimate effect of the required Act 162 analysis on the continuation of the utilities existing ECACs, but the Energy Agreement confirms the intent of the parties that the existing ECACs will continue, subject to periodic review by the PUC. As part of that periodic review, the parties agree that the PUC will examine whether there are renewable energy projects from which the utility should have, but did not, purchase energy or whether alternate fuel purchase strategies were appropriately used or not used.

On December 30, 2008, HECO and the Consumer Advocate filed joint proposed findings of fact and conclusions of law in the HECO 2007 test year rate case, which stated that, given the Energy Agreement, which documents a course of action to make Hawaii energy independent and recognizes the need to maintain HECO s financial health while achieving that objective, as well as the overwhelming support in the record for maintaining the ECAC in its current form, the PUC should determine that HECO s proposed ECAC complies with the requirements of Act 162.

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 the 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 September 30, 2009 noted in parentheses) include HECO s Campbell Industrial Park (CIP) combustion turbine No. 1 (CT-1) and a transmission line ($177 million), HECO s East Oahu Transmission Project ($45 million), HELCO s ST-7 ($90 million) and a customer information system ($24 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 (including the new unit) to the rest of the Oahu electric grid (collectively, the Project). The CT completed all utility requirements for system operation on August 3, 2009. Plans are for the CT to be run primarily as a peaking unit and to be fueled by biodiesel at a later date, when a supply of biodiesel fuel becomes available.

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. In May 2007, the PUC issued a D&O approving the Project and the DOH issued the final air permit, which became effective at the end of June 2007. The D&O further stated that no part of the Project costs may be included in HECO s rate base unless and until the Project is in fact installed, and is used and useful for public utility purposes. 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 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. HECO contends that the CIP CT-1 costs should be included in rate base in an interim decision and the final decision in the 2009 test year rate case.

In a related application filed with the PUC in June 2005, HECO requested approval of community benefit measures to mitigate the impact of the new generating unit on communities near the proposed generating unit site. In June 2007, the PUC issued a D&O which (1) approved HECO s request to commit funds for HECO s project to use recycled instead of potable water for industrial water consumption at the Kahe power plant, (2) approved HECO s request to commit funds for the environmental monitoring programs and (3) denied HECO s request to provide a base electric rate discount for HECO s residential customers who live near the proposed generation site. The approved measures are estimated to cost $11 million (through the first 10 years of implementation).

As of September 30, 2009, HECO s cost estimate for the Project (exclusive of the costs of the community benefit measures described above) was $193 million (of which $177 million had been incurred, including $9 million of AFUDC) and outstanding commitments for materials, equipment and outside services totaled $16 million. 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 September 30, 2009. 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.

In August 2007, HECO entered into a contract with Imperium Services, LLC (Imperium), to supply biodiesel for the planned generating unit, subject to PUC approval. In January 2009, HECO and Imperium amended the contract, Imperium assigned the contract to Imperium Grays Harbor, LLC (Imperium GH), and HECO filed the amended contract with the PUC. In August 2009, the PUC denied approval of the amended HECO contract with Imperium GH and a related terminalling and trucking agreement, indicating that HECO did not satisfy the burden of proof that the contracts, the costs of which will be passed directly to the ratepayers, were reasonable, prudent and in the public interest. The PUC also stated it remains strongly supportive of biofuels and other renewable energy resources. The commission s decision herein is not intended to reflect a decision as to the prudency of biodiesel or the proposed biodiesel feedstock. In September 2009, HECO solicited new bids from biofuel suppliers for CIP CT-1.

In October 2009, a process was established with PUC approval to allow HECO to use CIP CT-1 for critical load purposes, which HECO has done on one occasion.

Consistent with the plan approved by the PUC in its May 2007 order approving the Project, during the unit s initial period of commercial operation, it is undergoing testing using low sulfur diesel fuel to verify that performance guarantees from the vendor are met and to complete miscellaneous commissioning activities. This will be followed by testing using biofuels to obtain the data necessary for modification of the unit s air permit. Also consistent with the PUC s May 2007 order**,** HECO will be working with the PUC and Consumer Advocate to address contingency plans should there be a delay in securing a biofuel supplier for fuel to be used after the testing phase.

On October 2, 2009, HECO filed an application with the PUC for approval of a biodiesel supply contract for the CIP CT-1 biodiesel emissions data project and to include the contract costs in HECO s ECAC. The application also requests that HECO be allowed to use biodiesel blended with no more than 1% petroleum diesel (in addition to 100% biodiesel) to benefit from the federal biofuel blenders tax credit. On October 6, 2009, HECO purchased 400,000 gallons of biodiesel under the biodiesel supply contract, which contract, and the recovery of costs under it, has not yet been approved.

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East Oahu Transmission Project (EOTP). HECO had planned a project (EOTP) 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; see costs incurred below) for an EOTP, revised to use a 46 kV system and modified route, none of which is in conservation district lands. The environmental review process for the EOTP, as revised, was completed in 2005.

In written testimony filed in 2005, a consultant for the Consumer Advocate contended that HECO should always have planned for a project using only the 46 kV system and recommended that HECO be required to expense the $12 million incurred prior to the denial of the permit in 2002, and the related allowance for funds used during construction (AFUDC) of $5 million at the time. HECO contested the consultant s recommendation, emphasizing that the originally proposed 138 kV line would have been a more comprehensive and robust solution to the transmission concerns the project addresses. 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.

The project is currently estimated to cost $74 million and HECO plans to construct the EOTP in two phases. The first phase is currently in construction and projected to be completed in 2010. The second phase is projected to be completed in 2013. HECO, however, is evaluating an alternative which might result in faster implementation and lower cost for the second phase. A portion of this alternative has been awarded funding through the Smart Grid Investment Grant Program of the American Recovery and Reinvestment Act of 2009. PUC approval is required before the alternative can be implemented.

As of September 30, 2009, the accumulated costs recorded for the EOTP amounted to $45 million, including (i) $12 million of planning and permitting costs incurred prior to 2003, (ii) $12 million of planning, permitting and construction costs incurred after 2002 and (iii) $21 million for AFUDC. Management believes no adjustment to project costs is required as of September 30, 2009. 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 noise mitigation work is ongoing to ensure compliance with the applicable night-time noise 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, subject to PUC approval. Under the 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 in the first quarter of 2007 of $7 million (included in Other, net under Other income (loss) on HECO s consolidated statement of income).

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. However, the interim D&O does not commit the PUC to accept any of the amounts in the interim increase in its final D&O.

On June 22, 2009, ST-7 was placed into service. As of September 30, 2009, HELCO s cost estimate for ST-7 was $92 million (of which $90 million had been incurred and $2 million was estimated for ongoing peripheral work). HELCO intends to seek to recover the costs of ST-7 in HELCO s planned 2010 test year rate case.

Management believes no adjustment to project costs is required at September 30, 2009. 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 or disallow any ST-7 costs, 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. The application stated that the new CIS would allow the utilities to (i) more quickly and accurately store, maintain and manage customer-specific information necessary to provide basic customer service functions, such as producing bills, collecting payments, establishing service and fulfilling customer requests in the field, and (ii) have substantially greater capabilities and features than the existing system, enabling the utilities to enhance their operations, including customer service. 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 allowance for funds used during construction 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, alleging that HECO had wrongfully withheld payment of invoices under the contract. Peace filed a lawsuit against HECO the same day in the Hawaii United States District Court. Peace alleges, 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 counterclaims against Peace and Peace s former owner, First Data Corporation, for breach of contract and tortious interference.

The CIS project will continue with HECO selecting a new software vendor through a future competitive bid process, and HECO is currently preparing the request for proposal documents. As of September 30, 2009, the accumulated deferred and capital costs recorded for the CIS amounted to $24 million. Management believes no adjustment to project costs is required as of September 30, 2009. 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 producing in aggregate up to 400 MW of wind power 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 agrees 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 is pending a decision in a separate PUC proceeding. The application asks 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 through a surcharge mechanism. In September 2009, the PUC entered its order approving (with modifications) a stipulated procedural order and modifying the statement of issues for the docket.

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

HECO, HELCO and MECO, like other utilities, periodically 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 consolidated HECO s financial statements.

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

Honolulu Harbor investigation. 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. 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.

Besides subsurface investigation, assessments and preliminary oil removal tasks that have been conducted by the Participating Parties, HECO and others investigated their ongoing operations in the Iwilei Unit in 2003 to evaluate whether their facilities were active sources of petroleum contamination in the area. HECO s investigation concluded that its facilities were not then releasing petroleum. Routine maintenance and inspections of HECO facilities since then confirm that they are not currently releasing petroleum.

For administrative management purposes, the Iwilei Unit has been subdivided into four subunits. The Participating Parties have developed analyses of various remedial alternatives for the four subunits. The DOH uses the analyses to make a final determination of which remedial alternatives the Participating Parties will be required to implement. Once the DOH makes a remedial determination, the Participating Parties are required to develop remedial designs for the various elements of the remedy chosen. The DOH has completed remedial determinations for two subunits to date and the Participating Parties have initiated the remedial design work for those subunits. The Participating Parties anticipate that the DOH will complete the remaining remedial determinations during 2009 and anticipate that all remedial design work will be completed by the end of 2009 or early 2010. The Participating Parties will begin implementation of the remedial design elements as they are approved by the DOH.

Through September 30, 2009, HECO has accrued a total of $3.3 million for estimates of HECO s share of costs for continuing investigative work, remedial activities and monitoring for the Iwilei unit. As of September 30, 2009, the remaining accrual (amounts expensed less amounts expended) for the Iwilei unit was $1.6 million. Because (1) the

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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. To date, Hawaii has not developed an implementation plan. After Hawaii adopts its plan or the EPA issues an FIP, HECO, HELCO and MECO will evaluate the plan s impacts, if any. If any of the utilities generating units are ultimately required to install post-combustion control technologies to meet BART emission limits, the resulting capital and operation and maintenance costs could be significant.

Hazardous Air Pollutant (HAP) Control Steam Electric Generating Units. In February 2008, the federal Circuit Court of Appeals for the District of Columbia vacated the EPA s Delisting Rule, which had removed coal- and oil-fired electric generating units (EGUs) from the list of sources requiring control under Section 112 of the Clean Air Act. The EPA s request for a rehearing was denied. In October 2008, the EPA petitioned the U.S. Supreme Court to review the decision of the Circuit Court of Appeals for the District of Columbia vacating the EPA s Delisting Rule. Also, an industry group sought review of the Delisting Rule decision. On February 6, 2009, the EPA filed a motion with the Supreme Court to withdraw its petition for review. In the motion, the EPA indicated that it would begin rulemaking to establish MACT standards for EGUs. On February 23, 2009, the U.S. Supreme Court dismissed the petitions filed by the EPA and industry group requesting review of the decision vacating the EPA s Delisting Rule.

The EPA is thus required to develop Maximum Achievable Control Technology (MACT) standards for oil-fired EGU HAP emissions, including nickel compounds. On July 2, 2009, the EPA published in the Federal Register a notice of intent to issue an Information Collection Request (ICR) regarding coal-fired and oil-fired utility EGUs. The ICR will be the first step in the regulatory process to develop the MACT standards for utility EGUs. The EPA states that the purpose of the ICR is (1) to identify categories of affected sources and (2) to define the emission level being achieved by the average of the top performing 12% of the existing sources. The Clean Air Act mandates the average of the top performing 12% of existing sources (i.e., units with the lowest HAP emission rates) as the MACT standard for existing sources. The ICR will be applicable to HECO steam units and will require providing existing fuel and emissions data to the EPA as well as emission testing at each of HECO s steam generating plants on Oahu.

On October 22, 2009, the EPA filed in the United States District Court for the District of Columbia a proposed consent decree in American Nurses Association, et al. v. Jackson. The consent decree would require the EPA to propose MACT standards for coal- and oil-fired EGUs no later than March 16, 2011 and promulgate final standards no later than November 16, 2011. A public comment period will begin when the proposed consent decree is published in the Federal Register. The EPA is required to respond to any adverse comments before the consent decree becomes final.

Depending on the MACT standards developed (and the success of a potential challenge, after the MACT standards are issued, that the EPA inappropriately listed oil-fired EGUs initially), costs to comply with the standards could be significant. Management is currently evaluating its options regarding potential MACT standards for applicable HECO steam units, but will need to review the standards adopted by the EPA before determining its ultimate response and course of action.

Hazardous Air Pollutant (HAP) Control Reciprocating Internal Combustion Engines (RICE). On February 25, 2009, the EPA issued proposed MACT standards that would regulate HAPs from certain existing diesel compression ignition engines and gasoline spark ignition engines (i.e., RICE). As proposed, the RICE MACT rule would require installation of pollution control devices on 80 RICE at the utilities facilities. Eight of the utilities RICE would be required to implement only specified maintenance practices, rather than install pollution control equipment. If adopted, the RICE MACT rule would provide a three-year compliance period after its effective date. Under the terms

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of a consent decree, the EPA is required to complete the final rule by February 10, 2010. Management is evaluating the impacts of the proposed RICE MACT rule, including potential capital expenditures and other compliance costs.

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. In 2004, the EPA issued a rule establishing design, construction and capacity standards for existing cooling water intake structures, such as those at HECO s Kahe, Waiau and Honolulu generating stations, and required demonstrated compliance by March 2008. The rule provided a number of compliance options, some of which were far less costly than others. HECO had retained a consultant that was developing a cost effective compliance strategy.

In January 2007, the U.S. Circuit Court of Appeals for the Second Circuit issued a decision that remanded for further consideration and proceedings significant portions of the rule and found other portions to be impermissible, including the EPA s use of a cost-benefit analysis to determine compliance options. In July 2007, the EPA formally suspended the rule and provided guidance to federal and state permit writers that they should use their best professional judgment in determining permit conditions regarding cooling water intake requirements at existing power plants.

HECO facilities were subject to permit renewal in mid-2009. HECO timely submitted permit renewal applications for its facilities in 2009. The existing permits remain in force until renewals are issued. The renewed permits, when issued, may include new permit conditions to address cooling water intake requirements.

In April 2008, the U.S. Supreme Court agreed to review the Second Circuit Court of Appeal s rejection of a cost-benefit test to determine compliance options. On April 1, 2009, the Supreme Court issued its opinion, ruling that it was permissible, but not required, for the EPA to rely on a cost-benefit analysis in developing cooling water intake standards under the Clean Water Act and to allow variances from the standards based on a cost-benefit comparison. The Supreme Court remanded the case. Because it remains unclear what form the regulations will take and whether the EPA will retain the cost-benefit portions of the rule, management is unable to predict which compliance options, some of which could entail significant capital expenditures to implement, will be applicable to its facilities. It is anticipated that the EPA will issue draft rules in mid-2010.

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 (including the electric utilities), 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 from sources or categories of sources of greenhouse gases 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. Because the full scope of the Task Force report remains to be determined and regulations implementing Act 234 have not yet been promulgated, management cannot predict the impact of Act 234 on the electric utilities and the Company.

Management believes that, in addition to the state s activities, federal legislative and regulatory action to control and reduce GHG emissions is likely.

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 to 17% by 2020, 42% by 2030, and 83% by 2050. ACES also establishes a trading and offset scheme for GHG allowances. The trading program combined with the declining cap is known as a cap and trade approach to emissions reduction. In September 2009, the U.S. Senate began consideration of the Clean Energy Jobs and American Power Act (S.1733) introduced by Senators Kerry and Boxer. S. 1733 also includes cap and trade provisions to reduce GHG emissions.

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On April 7, 2007, in Massachusetts v. EPA, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG emissions from motor vehicles under the Clean Air Act (CAA or the Act). The Court further ruled that the EPA must determine whether or not motor vehicle GHG emissions cause or contribute to air pollution which may be reasonably anticipated to endanger public health or welfare (known as an endangerment finding), or whether the science about GHGs was too uncertain to make a reasoned decision. Under President Obama s administration, the EPA has accelerated rulemaking to address GHG emission control in both stationary and mobile sources.

In April 2009, the EPA proposed making the finding that motor vehicle GHG emissions endanger public health or welfare. Although a separate finding will have to be made for stationary sources like the utilities generating units, the language regarding mobile sources in the CAA requiring endangerment findings prior to regulation is virtually identical to the CAA language for stationary sources. Thus, there is little doubt that the EPA will make the same or similar endangerment finding regarding GHG emissions from stationary sources. 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. The rule applies to fossil fuel suppliers and industrial gas suppliers, as well as to direct GHG emitters, including the utilities. The rule 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.

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 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, which would last for 6 years, would establish a temporary major stationary source applicability threshold of 25,000 tons per year of carbon dioxide equivalent (tpyCO_2e) to determine if an existing source would be required to obtain a Title V operating permit (known as a Covered Source Permit in Hawaii) and a temporary PSD significance level between 10,000 and 25,000 tpyCO_2e. Modifications of existing units that result in increases in emissions in excess of PSD significance levels trigger analysis under the PSD program including new source review. Within 5 years of the final tailoring rule, the EPA would conduct a study to assess administrability issues of the rule, and, if appropriate, conduct another rulemaking by the end of the 6th 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 1 year following the effective date of the final rule. These rules are being proposed and adopted 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.

Apollo Energy Corporation/Tawhiri Power LLC. HELCO purchases energy generated at the Kamao a wind farm pursuant to the Restated and Amended Power Purchase Contract 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 ouput of the wind farm is 20 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. A panel of three neutral arbitrators has been formed and a hearing has been scheduled for January 2010.

By letter to Tawhiri dated September 23, 2009, HELCO requested binding arbitration as provided for under the provisions of the RAC on three issues related to the Kamao a switching station under the terms of the RAC: (1) transfer of the title/bill of sale for the switching station to HELCO; (2) transfer of an interest in land for the switching station necessary for HELCO to operate and maintain it; and (3) reimbursements of certain of HELCO s interconnection costs in connection with the construction of the switching station. HELCO also indicated the Tawhiri RAC would be terminated if Tawhiri did not cure its breaches under the RAC. On October 13, 2009, Tawhiri submitted its response, denying any breaches of the RAC that would justify its termination and stating that the issues related to interconnection costs involve the interpretation of the various orders of the PUC related to the RAC, rather than the interpretation and application of the terms and conditions of the RAC itself. On October 19, 2009 Tawhiri petitioned the PUC for a ruling that the RAC and the PUC s order approving it required HELCO to reimburse Tawhiri $2.1 million for interconnections costs. Management is vigorously disputing this claim. Under the RAC, the parties are required to continue to negotiate for 60 days before proceeding to arbitration.

In addition to the curtailment and switching station issues, HELCO and Tawhiri have a dispute relating to reconciliation of transmission line losses, which dispute has not yet proceeded to arbitration.

Asset retirement obligation. In July 2009, HECO hired a 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 portion of the plant. The inspection indicated that retired Generating Units Nos. 5 and 7 at the plant were deteriorating, and the hygienist recommended removing the asbestos-containing materials and lead based paint. The asbestos and lead based paint, in their current state, do not pose any health risks as these hazardous materials are confined to a sealed/vacant portion of the plant. Currently, HECO 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 retirements and environmental obligations, in September 2009, HECO recorded an asset retirement obligation estimated at $23 million.

Collective bargaining agreements. As of September 30, 2009, 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 new collective bargaining and benefit agreements with HECO, HELCO and MECO. The new 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 $4 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.

6 Cash flows

Supplemental disclosures of cash flow information. For the nine months ended September 30, 2009 and 2008, HECO and its subsidiaries paid interest amounting to $29 million and $33 million, respectively.

For the nine months ended September 30, 2009 and 2008, HECO and its subsidiaries paid income taxes amounting to $12 million and $87 million, respectively. The significant change was due primarily to the differences in the taxes refundable or due with the extensions for tax years 2008 and 2007 and in the estimated tax payments due for the first three quarters of 2009 and the first three quarters of 2008. In 2007, taxable income was significantly larger in the fourth quarter when compared to the first three quarters, resulting in a larger portion of the 2007 taxes paid with the extension filed in the first quarter of 2008. Taxable income for 2008 was larger in the first half versus the second half of the year, resulting in overpayments being refunded in the first quarter of 2009. This larger taxable income also resulted in disproportionately higher estimated tax payments for the first three quarters of 2008 versus the first three quarters of 2009.

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 $10.4 million and $6.4 million for the nine months ended September 30, 2009 and 2008, 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.

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

Cash and equivalents and short-term borrowings

The carrying amount approximated fair value because of the short maturity of these instruments.

Long-term debt

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

Off-balance sheet financial instruments

Fair value of HECO-obligated preferred securities of trust subsidiaries was based on quoted market prices.

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

	September 30, 2009		December 31, 2008	
(in thousands)	Carrying amount	Estimated fair value	Carrying amount	Estimated fair value
Financial assets				
Cash and equivalents	$ 6,486	$ 6,486	$ 6,901	$ 6,901
Financial liabilities				
Short-term borrowings from affiliate	10,700	10,700	41,550	41,550
Long-term debt, net, including amounts due within one year	1,057,784	1,011,095	904,501	660,380
Off-balance sheet item				
HECO-obligated preferred securities of trust subsidiary	50,000	47,440	50,000	40,420

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

	Three months ended September 30		Nine months ended September 30	
(in thousands)	2009	2008	2009	2008
Operating income from regulated and nonregulated activities before income taxes (per HEI consolidated statements of income)	$ 54,172	$ 51,847	$ 117,404	$ 158,226
Deduct:				
Income taxes on regulated activities	(15,957)	(15,035)	(33,228)	(47,507)
Revenues from nonregulated activities	(1,938)	(1,664)	(7,031)	(4,533)
Add:	373	266	777	1,282
Expenses from nonregulated activities				
Operating income from regulated activities after income taxes (per HECO consolidated statements of income)	$ 36,650	$ 35,414	$ 77,922	$ 107,468

10 Subsequent events

HECO and its subsidiaries have evaluated subsequent events through November 2, 2009, the date the financial statements were issued.

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 September 30, 2009

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

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Three months ended September 30, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Operating revenues	$ 575,033	122,190	128,901				$ 826,124
Operating expenses							
Fuel oil	271,889	30,148	75,120				377,157
Purchased power	140,757	49,645	11,723				202,125
Other operation	44,377	7,619	9,603				61,599
Maintenance	16,574	4,485	4,115				25,174
Depreciation	20,553	7,818	7,048				35,419
Taxes, other than income taxes	51,485	10,923	11,793				74,201
Income taxes	8,728	3,675	2,632				15,035
	554,363	114,313	122,034				790,710
Operating income	20,670	7,877	6,867				35,414
Other income							
Allowance for equity funds used during construction	1,822	463	141				2,426
Equity in earnings of subsidiaries	10,754					(10,754)	
Other, net	1,508	386	81	(14)	(25)	(450)	1,486
	14,084	849	222	(14)	(25)	(11,204)	3,912
Interest and other charges							
Interest on long-term debt	7,649	1,965	2,265				11,879
Amortization of net bond premium and expense	403	108	121				632
Other interest charges	1,216	434	152			(450)	1,352
Allowance for borrowed funds used during construction	(716)	(194)	(57)				(967)
	8,552	2,313	2,481			(450)	12,896
Net income (loss)	26,202	6,413	4,608	(14)	(25)	(10,754)	26,430
Less net income attributable to noncontrolling interest preferred stock of subsidiaries		133	95				228
Net income (loss) attributable to HECO	26,202	6,280	4,513	(14)	(25)	(10,754)	26,202
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 25,932	6,280	4,513	(14)	(25)	(10,754)	$ 25,932

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Nine months ended September 30, 2009

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

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Nine months ended September 30, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Operating revenues	$ 1,458,621	332,811	343,833				$ 2,135,265
Operating expenses							
Fuel oil	632,415	79,194	188,846				900,455
Purchased power	367,450	131,590	31,106				530,146
Other operation	125,108	23,979	27,513				176,600
Maintenance	48,008	12,785	11,984				72,777
Depreciation	61,657	23,454	21,143				106,254
Taxes, other than income taxes	132,595	30,110	31,353				194,058
Income taxes	28,158	9,978	9,371				47,507
	1,395,391	311,090	321,316				2,027,797
Operating income	63,230	21,721	22,517				107,468
Other income							
Allowance for equity funds used during construction	4,957	1,069	406				6,432
Equity in earnings of subsidiaries	31,519					(31,519)	
Other, net	4,079	983	191	(54)	(347)	(1,159)	3,693
	40,555	2,052	597	(54)	(347)	(32,678)	10,125
Interest and other charges							
Interest on long-term debt	22,761	5,875	6,777				35,413
Amortization of net bond premium and expense	1,203	332	367				1,902
Other interest charges	3,004	1,205	347			(1,159)	3,397
Allowance for borrowed funds used during construction	(1,942)	(456)	(166)				(2,564)
	25,026	6,956	7,325			(1,159)	38,148
Net income (loss)	78,759	16,817	15,789	(54)	(347)	(31,519)	79,445
Less net income attributable to noncontrolling interest preferred stock of subsidiaries		400	286				686
Net income (loss) attributable to HECO	78,759	16,417	15,503	(54)	(347)	(31,519)	78,759
Preferred stock dividends of HECO	810						810
Net income (loss) for common stock	$ 77,949	16,417	15,503	(54)	(347)	(31,519)	$ 77,949

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

September 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and Eliminations	HECO consolidated
Assets							
Utility plant, at cost							
Land	$ 42,073	4,982	4,346				$ 51,401
Plant and equipment	2,775,510	981,489	855,114				4,612,113
Less accumulated depreciation	(1,067,985)	(373,390)	(381,485)				(1,822,860)
Construction in progress	126,827	15,926	12,712				155,465
Net utility plant	1,876,425	629,007	490,687				2,996,119
Investment in wholly owned subsidiaries, at equity	450,905					(450,905)	
Current assets							
Cash and equivalents	2,870	2,182	1,312	99	23		6,486
Advances to affiliates	25,350		10,000			(35,350)	
Customer accounts receivable, net	90,198	24,974	18,537				133,709
Accrued unbilled revenues, net	66,458	13,557	12,346				92,361
Other accounts receivable, net	7,059	3,382	1,179			(3,412)	8,208
Fuel oil stock, at average cost	39,517	10,703	17,669				67,889
Materials & supplies, at average cost	18,867	4,080	13,410				36,357
Prepayments and other	8,604	3,114	2,647			(486)	13,879
Total current assets	258,923	61,992	77,100	99	23	(39,248)	358,889
Other long-term assets							
Regulatory assets	394,164	76,343	64,780				535,287
Unamortized debt expense	10,158	2,754	2,272				15,184
Other	43,884	10,062	15,454				69,400
Total other long-term assets	448,206	89,159	82,506				619,871
	$ 3,034,459	780,158	650,293	99	23	(490,153)	$ 3,974,879
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,212,393	231,895	218,897	94	19	(450,905)	$ 1,212,393
Cumulative preferred stock not subject to mandatory redemption	22,293						22,293
Noncontrolling interest cumulative preferred stock of subsidiaries not subject to mandatory redemption		7,000	5,000				12,000
Stockholders equity	1,234,686	238,895	223,897	94	19	(450,905)	1,246,686
Long-term debt, net	672,184	211,240	174,360				1,057,784

Total capitalization	1,906,870	450,135	398,257	94	19	(450,905)	2,304,470
Current liabilities							
Short-term borrowings affiliate	20,700	25,350				(35,350)	10,700
Accounts payable	86,838	18,803	12,401				118,042
Interest and preferred dividends payable	13,263	3,938	3,903			(8)	21,096
Taxes accrued	101,834	28,603	25,260			(486)	155,211
Other	28,015	10,559	13,210	5	4	(3,404)	48,389
Total current liabilities	250,650	87,253	54,774	5	4	(39,248)	353,438
Deferred credits and other liabilities							
Deferred income taxes	140,321	25,017	12,998				178,336
Regulatory liabilities	191,994	52,124	38,121				282,239
Unamortized tax credits	32,133	13,034	12,718				57,885
Retirement benefits liability	296,063	52,187	51,289				399,539
Other	35,948	35,099	12,470				83,517
Total deferred credits and other liabilities	696,459	177,461	127,596				1,001,516
Contributions in aid of construction	180,480	65,309	69,666				315,455
	$ 3,034,459	780,158	650,293	99	23	(490,153)	$ 3,974,879

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

December 31, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and Eliminations	HECO consolidated
Assets							
Utility plant, at cost							
Land	$ 33,213	4,982	4,346				$ 42,541
Plant and equipment	2,567,018	874,322	836,159				4,277,499
Less accumulated depreciation	(1,028,501)	(352,382)	(360,570)				(1,741,453)
Construction in progress	188,754	68,650	9,224				266,628
Net utility plant	1,760,484	595,572	489,159				2,845,215
Investment in wholly owned subsidiaries, at equity	437,033					(437,033)	
Current assets							
Cash and equivalents	2,264	3,148	1,349	123	17		6,901
Advances to affiliates	62,000		12,000			(74,000)	
Customer accounts receivable, net	109,724	32,108	24,590				166,422
Accrued unbilled revenues, net	74,657	17,876	14,011				106,544
Other accounts receivable, net	3,983	2,217	1,143		11	564	7,918
Fuel oil stock, at average cost	53,546	10,326	13,843				77,715
Materials & supplies, at average cost	16,583	4,366	13,583				34,532
Prepayments and other	6,918	2,311	3,664			(267)	12,626
Total current assets	329,675	72,352	84,183	123	28	(73,703)	412,658
Other long-term assets							
Regulatory assets	388,054	77,038	65,527				530,619
Unamortized debt expense	9,802	2,282	2,419				14,503
Other	38,099	7,699	7,197		119		53,114
Total other long-term assets	435,955	87,019	75,143		119		598,236
	$ 2,963,147	754,943	648,485	123	147	(510,736)	$ 3,856,109
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,188,842	221,405	215,382	105	141	(437,033)	$ 1,188,842
Cumulative preferred stock not subject to mandatory redemption	22,293						22,293
Noncontrolling interest cumulative preferred stock of subsidiaries not subject to mandatory redemption		7,000	5,000				12,000
Stockholders equity	1,211,135	228,405	220,382	105	141	(437,033)	1,223,135
Long-term debt, net	582,132	148,030	174,339				904,501

Total capitalization	1,793,267	376,435	394,721	105	141	(437,033)	2,127,636
Current liabilities							
Short-term borrowings affiliate	53,550	62,000				(74,000)	41,550
Accounts payable	84,238	27,795	10,961				122,994
Interest and preferred dividends payable	10,242	2,547	2,819			(211)	15,397
Taxes accrued	144,366	38,117	37,830			(267)	220,046
Other	33,462	9,015	11,992	18	6	775	55,268
Total current liabilities	325,858	139,474	63,602	18	6	(73,703)	455,255
Deferred credits and other liabilities							
Deferred income taxes	134,359	19,621	12,330				166,310
Regulatory liabilities	202,003	49,843	36,756				288,602
Unamortized tax credits	32,501	13,476	12,819				58,796
Retirement benefits liability	284,826	54,664	53,355				392,845
Other	11,576	35,432	7,941				54,949
Total deferred credits and other liabilities	665,265	173,036	123,201				961,502
Contributions in aid of construction	178,757	65,998	66,961				311,716
	$ 2,963,147	754,943	648,485	123	147	(510,736)	$ 3,856,109

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Stockholders Equity (unaudited)

Nine months ended September 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Balance, December 31, 2008	$ 1,211,135	228,405	220,382	105	141	(437,033)	$ 1,223,135
Comprehensive income:							
Net income (loss)	56,951	10,879	8,048	(11)	(147)	(18,083)	57,637
Retirement benefit plans:							
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes	8,008	1,206	989			(2,195)	8,008
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits	(7,835)	(1,193)	(971)			2,164	(7,835)
Comprehensive income (loss)	57,124	10,892	8,066	(11)	(147)	(18,114)	57,810
Capital stock expense	(7)	(2)	(1)			3	(7)
Common stock dividends	(32,756)		(4,264)			4,264	(32,756)
Preferred stock dividends	(810)	(400)	(286)				(1,496)
Issuance of common stock					25	(25)	
Balance, September 30, 2009	$ 1,234,686	238,895	223,897	94	19	(450,905)	$ 1,246,686

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Stockholders Equity (unaudited)

Nine months ended September 30, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Balance, December 31, 2007	$ 1,132,755	208,820	213,521	182	388	(410,911)	$ 1,144,755
Comprehensive income:							
Net income (loss)	78,759	16,817	15,789	(54)	(347)	(31,519)	79,445
Retirement benefit plans:							
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes	4,099	569	464			(1,033)	4,099
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits	(3,928)	(554)	(446)			1,000	(3,928)
Comprehensive income (loss)	78,930	16,832	15,807	(54)	(347)	(31,552)	79,616
Common stock dividends	(14,088)		(10,965)			10,965	(14,088)

Preferred stock dividends	(810)	(400)	(286)				(1,496)
Issuance of common stock					100	(100)	
Balance, September 30, 2008	$ 1,196,787	225,252	218,077	128	141	(431,598)	$ 1,208,787

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Nine months ended September 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Cash flows from operating activities							
Net income (loss)	$ 56,951	10,879	8,048	(11)	(147)	(18,083)	$ 57,637
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(18,158)					18,083	(75)
Common stock dividends received from subsidiaries	4,339					(4,264)	75
Depreciation of property, plant and equipment	61,523	24,754	22,129				108,406
Other amortization	2,804	2,554	2,344				7,702
Changes in deferred income taxes	6,081	5,414	1,037				12,532
Changes in tax credits, net	115	(332)	(284)				(501)
Allowance for equity funds used during construction	(8,254)	(1,530)	(569)				(10,353)
Changes in assets and liabilities:							
Decrease in accounts receivable	16,450	5,969	6,017		11	3,976	32,423
Decrease in accrued unbilled revenues	8,199	4,319	1,665				14,183
Decrease (increase) in fuel oil stock	14,029	(377)	(3,826)				9,826
Decrease (increase) in materials and supplies	(2,284)	286	173				(1,825)
Increase in regulatory assets	(7,460)	(2,973)	(3,396)				(13,829)
Increase (decrease) in accounts payable	2,600	(8,992)	1,440				(4,952)
Changes in prepaid and accrued income and utility revenue taxes	(42,546)	(9,342)	(10,500)				(62,388)
Changes in other assets and liabilities	12,299	(4,439)	(509)	(13)	(2)	(3,976)	3,360
Net cash provided by (used in) operating activities	106,688	26,190	23,769	(24)	(138)	(4,264)	152,221
Cash flows from investing activities							
Capital expenditures	(159,900)	(55,283)	(22,481)				(237,664)
Contributions in aid of construction	4,253	1,993	1,226				7,472
Advances from affiliates	36,650		2,000			(38,650)	
Other	221				119		340
Investment in consolidated subsidiary	(25)					25	
Net cash provided by (used in) investing activities	(118,801)	(53,290)	(19,255)		119	(38,625)	(229,852)
Cash flows from financing activities							
Common stock dividends	(32,756)		(4,264)			4,264	(32,756)
Preferred stock dividends	(810)	(400)	(286)				(1,496)
Proceeds from issuance of long-term debt	90,000	63,186					153,186
Proceeds from issuance of common stock					25	(25)	
Net decrease in short-term borrowings from affiliate with original maturities of three months or less	(32,850)	(36,650)				38,650	(30,850)
Decrease in cash overdraft	(9,847)						(9,847)
Other	(1,018)	(2)	(1)				(1,021)
Net cash provided by (used in) financing activities	12,719	26,134	(4,551)		25	42,889	77,216

Net increase (decrease) in cash and equivalents		606	(966)	(37)	(24)	6	(415)
Cash and equivalents, beginning of period		2,264	3,148	1,349	123	17	6,901
Cash and equivalents, end of period	$	2,870	2,182	1,312	99	23	$ 6,486

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Nine months ended September 30, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Cash flows from operating activities							
Net income (loss)	$ 78,759	16,817	15,789	(54)	(347)	(31,519)	$ 79,445
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(31,594)					31,519	(75)
Common stock dividends received from subsidiaries	11,040					(10,965)	75
Depreciation of property, plant and equipment	61,657	23,454	21,143				106,254
Other amortization	2,368	532	3,526				6,426
Changes in deferred income taxes	6,244	1,939	(1,595)				6,588
Changes in tax credits, net	588	759	156				1,503
Allowance for equity funds used during construction	(4,957)	(1,069)	(406)				(6,432)
Changes in assets and liabilities:							
Increase in accounts receivable	(40,569)	(14,145)	(12,140)			7,303	(59,551)
Increase in accrued unbilled revenues	(16,483)	(3,242)	(3,669)				(23,394)
Increase in fuel oil stock	(73,820)	(3,702)	(2,171)				(79,693)
Decrease (increase) in materials and supplies	(2,816)	(637)	18				(3,435)
Decrease (increase) in regulatory assets	1,804	182	(2,014)				(28)
Increase (decrease) in accounts payable	37,035	13,550	(4,261)				46,324
Changes in prepaid and accrued income and utility revenue taxes	(1,938)	(1,684)	(4,347)				(7,969)
Changes in other assets and liabilities	1,999	(4,899)	4,865	(4)	(44)	(7,303)	(5,386)
Net cash provided by (used in) operating activities	29,317	27,855	14,894	(58)	(391)		