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

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. I 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)

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other comprehensive loss	Noncontrolling interest: cumulative preferred stock of 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

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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.

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 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:

	Three months ended September 30		**Nine months ended September 30**	
($ in millions)	**2009**	**2008**	**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:

($ 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/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.

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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.

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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	2008	Nine months ended September 30 2009	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.

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:

Renewable energy and energy efficiency goals. The Energy Agreement provides for the parties to pursue an overall goal of providing 70% of Hawaii s electricity and ground transportation energy needs from clean energy sources, including renewable energy and energy efficiency, by 2030. The ground transportation energy needs included in this goal include a contemplated move in Hawaii to electrification of transportation and the use of electric utility capacity in off peak hours to recharge vehicles and batteries. To 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).

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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

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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.

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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

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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.

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)	(10,965)	60,652
Cash flows from investing activities							
Capital expenditures	(90,318)	(56,692)	(23,311)				(170,321)
Contributions in aid of construction	7,574	3,092	1,600				12,266
Advances from (to) affiliates	(39,550)		2,000			37,550	
Investment in consolidated subsidiary	(100)					100	
Other	862				(113)		749
Net cash used in investing activities	(121,532)	(53,600)	(19,711)		(113)	37,650	(157,306)
Cash flows from financing activities							
Common stock dividends	(14,088)		(10,965)			10,965	(14,088)
Preferred stock dividends	(810)	(400)	(286)				(1,496)
Proceeds from issuance of long-term debt	14,399	1,628	2,680				18,707
Proceeds from issuance of common stock					100	(100)	
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	110,204	23,550	16,000			(37,550)	112,204
Decrease in cash overdraft	(8,581)		(1)				(8,582)
Net cash provided by financing activities	101,124	24,778	7,428		100	(26,685)	106,745

Net increase (decrease) in cash and equivalents		8,909	(967)	2,611	(58)	(404)		10,091
Cash and equivalents, beginning of period		203	3,069	773	198	435		4,678
Cash and equivalents, end of period	$	9,112	2,102	3,384	140	31	$	14,769

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

The following discussion updates Management s Discussion and Analysis of Financial Condition and Results of Operations incorporated by reference in HEI s and HECO s Form 10-K for the year ended December 31, 2008 and should be read in conjunction with the annual (as of and for the year ended December 31, 2008) included in HEI s and HECO s Form 8-K dated June 9, 2009, and the quarterly (as of and for the three months ended March 31, 2009, as of and for the three and six months ended June 30, 2009 and as of and for the three and nine months ended September 30, 2009) consolidated financial statements of HEI and HECO and accompanying notes included in the Forms 10-Q for the first, second and third quarters of 2009.

HEI Consolidated

RESULTS OF OPERATIONS

(in thousands, except per share amounts)	Three months ended September 30, 2009	2008	% change	Primary reason(s) for significant change*
Revenues	$ 620,313	$ 915,431	(32)	Decrease for the electric utility and the bank segments
Operating income	68,639	74,129	(7)	Decrease for the bank and other segments, partly offset by an increase for the electric utility segment
Net income for common stock	33,483	37,281	(10)	Lower operating income, partly offset by lower income taxes** and higher AFUDC
Basic earnings per common share	$ 0.37	$ 0.44	(16)	Lower net income and higher weighted average shares outstanding
Weighted-average number of common shares outstanding	91,522	84,625	8	Issuances of shares through a common stock offering in December 2008 and the HEI Dividend Reinvestment and Stock Purchase Plan and other Company plans

(in thousands, except per share amounts)	Nine months ended September 30 2009	2008	% change	Primary reason(s) for significant change*
Revenues	$ 1,690,011	$ 2,419,103	(30)	Decrease for the electric utility and the bank segments
Operating income	148,352	166,477	(11)	Decrease for the electric utility and other segments, partly offset by an increase for the bank segment (resulting from the impact of the June 2008 balance sheet restructuring)
Net income for common stock	69,357	76,384	(9)	Lower operating income, partly offset by higher AFUDC and lower interest expense other than on deposit liabilities and other bank borrowings and income taxes**
Basic earnings per common share	$ 0.76	$ 0.91	(16)	Lower net income and higher weighted average shares outstanding
Weighted-average number of common shares outstanding	91,173	84,052	8	Issuances of shares through a common stock offering in December 2008 and the HEI Dividend Reinvestment and Stock Purchase Plan and other Company plans

* Also, see segment discussions which follow.

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** The Company s effective tax rates (federal and state) for the third quarters of 2009 and 2008 were 36% and 35%, respectively. The Company s effective tax rate for the first nine months of 2009 and 2008 was 34%.

Dividends. The payout ratios for 2008 and the first nine months of 2009 were 116% and 122%, respectively. Excluding the $35.6 million net charge related to ASB s balance sheet restructuring (and disregarding other adjustments to net income that would be necessary to more fully reflect the impact on net income if the restructuring had not occurred), the payout ratio for 2008 would have been 83%. HEI currently expects to maintain the dividend at its present level; however, the HEI Board of Directors evaluates the dividend quarterly and considers many factors in the evaluation, including but not limited to the Company s results of operations, the long-term prospects for the Company, and current and expected future economic conditions.

Economic conditions

Note: The statistical data in this section is from public third-party sources (e.g., Department of Business, Economic Development and Tourism; University of Hawaii Economic Research Organization; Hawaii Department of Labor and Industrial Relations; Honolulu Board of Realtors ,Realtors Association of Maui, Century 21 Kauai Real Estate, The Conference Board, Blue Chip Financial Forecasts; national and local newspapers).

On a national level, improving economic data referred to as green shoots cited in the second quarter of 2009 became full-fledged positive data points in the third quarter of 2009. In September 2009, the Conference Board s index of leading economic indicators rose for the sixth consecutive month, the strongest six-month gain since 1983 and the October 1, 2009 Blue Chip Financial Forecast reported a real gross domestic product (GDP) consensus forecast of 3.2% for the third quarter of 2009, the first positive measure since the second quarter of 2008, and its GDP forecast for the fourth quarter of 2009 was revised upward to 2.5% from the July 1, 2009 forecast of 1.8%. Further, at October 1, 2009, more than 90% of the Blue Chip panelists agreed that the deepest recession since World War II has ended. Positive data points are continuing in the fourth quarter of 2009. On October 14, 2009, the Dow Jones Industrial Average (Dow) broke the psychologically-important 10,000 mark, a level not seen since the credit crisis in the fall of 2008 and a sign that investors believe the economy is improving. The Dow has recovered 53% since early March 2009 when stocks reached their lowest levels in more than a decade.

Hawaii economic growth, as measured by the change in real personal income, has been revised upward from the second quarter of 2009; although still negative, it is projected to be lower by 1.1% and 0.2% in 2009 and 2010, respectively, before a moderate positive recovery of 1.5% is predicted for 2011.

The Hawaii economy generally lags behind the U.S. economy in recovery and continued to be weak in the third quarter of 2009. The State continues to be challenged by its budget deficit predicted to be $1 billion through June 2011. During the third quarter of 2009, Governor Lingle instituted furlough days and salary reductions for executive branch officials and ordered layoffs of approximately 1,100 State employees (a number now estimated at 750) beginning in November 2009 as initial steps to address the shortfall. In addition, in September 2009, the Hawaii State Teachers Association ratified a contract with furlough days estimated to equal an 8% labor cost savings. Further, in October 2009, the Hawaii Government Employees Association (HGEA) ratified a new two-year contract that affects nearly 30,000 employees in various state and county areas. The HGEA agreement is estimated to equal about an 8% cut in pay accomplished through furlough days between 2009 and 2011 and is the first time the union has conceded to a significant salary reduction.

Weakness is most notable in one of the State s largest industries, tourism, which is affected by the health of the U.S. and key international economies, especially Japan. While still negative, total visitor arrivals appear to have stabilized near the 2002-2003 level and projections for visitor arrivals have been revised upward, projected to be 4.4% lower than 2008, compared to the June 2009 estimate of a 6.8% decline. However, recovery is expected to be slow as U.S. and Japanese consumers remain cautious. On a positive note, Japan s economy returned to growth in the second quarter of 2009 and Japanese visitor arrivals recovered sooner than expected from the H1N1 scare. Japanese arrivals for 2009 have been revised upward from the June 2009 forecast and are now expected to be 4.1% lower than in 2008, rather than 13.8% lower. 2009 U.S. visitor arrivals are close to expectation and are forecasted to be 3.3% lower than 2008 with positive growth of 2.7% projected for 2010. The weakness in tourism is expected to impact the neighbor island economies more than Oahu because their economies rely more on tourism.

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With the hotel industry in the U.S. experiencing its worst downturn since the Great Depression, the impact to Hawaii is severe. Occupancy rates at Hawaii hotels are expected to average 66% in 2009 and remain below 70% through 2011. In addition, continued widespread discounting is resulting in forecasted visitor expenditures declining 12% in 2009 from 2008 before an increase of 2% is projected in 2010.

At 7.2%, seasonally-adjusted Hawaii unemployment at the end of September 2009 remains below the national average of 9.8%, but is much higher than the averages of 2.6% for 2007 and 4% for 2008. The Hawaii unemployment rate is projected to be 7.4% in 2009 and to rise to 8.1% in 2010 before gradually receding back to 7.5% in 2011. Hawaii s relative high unemployment rate is anticipated to further stress businesses as unemployment insurance taxes are expected to be raised beginning in April 2010 due to the projection that the unemployment insurance trust fund balance will be below an adequate level. The declines in tourism-related sectors and construction have resulted, and will continue to result, in job losses. The job base is expected to contract by 3.0% and 0.8% in 2009 and 2010, respectively, before projected recovery of 0.9% begins in 2011.

The Oahu housing market saw slight improvement in September 2009 with increases to both home sales and prices for the first time since 2006 although year-to-date 2009 sales remain at a 10-year low and demand remains relatively weak. Sales have been challenged by stricter mortgage underwriting guidelines and Hawaii further suffers from the credit freeze in the jumbo-loan market and for second home purchases. Total single-family home sales on Oahu for the first nine months of 2009 were 16.2% lower with median prices paid 8.0% lower than the same period in 2008. The recent surge in sales is not considered an overall rebound but is being explained as a rush of first-time buyers taking advantage of the federal tax credit. Lower home prices and relatively low mortgage rates have helped the consumer psychology and local authorities note that the housing market appears to be bottoming if it hasn t already moved past a bottom point. The median Oahu sales price of $600,000 in September 2009 was a 1.7% increase from the same period last year. Maui and Kauai housing markets are weaker than Oahu. For the first nine months of 2009, Maui and Kauai experienced home sales declines of 36% and 26% and price declines 18% and 25%, respectively. The finite supply of developable land in Hawaii has been a stabilizing force although the pessimistic outlook for jobs and job growth puts continued downward pressure on prices and increases the risk for additional foreclosures. For the third quarter of 2009, foreclosures in Hawaii continued to rise and Hawaii ranked 14th among states for overall foreclosure activity at 1/185 households. The state s foreclosure rate was favorable to the national rate of 1/136 households although the rate on Maui (1/111) and Kauai (1/85) both were worse than the national rate.

While credit markets have improved, conditions are still tight and the downturn in Hawaii s construction industry is expected to continue as commercial, industrial and resort development are hampered by the weak economic outlook. Residential construction is also expected to be lower with residential permits predicted to drop 44% in 2009, followed by a further 4% drop in 2010. Government spending initiatives have been delayed with the surge in government contracts pushed back one year to 2010. Thus, while real government contracts awarded are estimated to grow 4.5% in 2009, the significant growth is now estimated to occur in 2010 with an increase of 36%, or nearly $1.4 billion in construction activity.

The signs of recovery in the U.S. and Japan are positive indicators for the Hawaii economy although weakness is still expected for the remainder of the year. Assuming national and international economic conditions continue to improve, Hawaii is expected to see gradual recovery beginning in 2010 that continues into 2012.

Emergency Economic Stabilization Act of 2008 and American Economic Recovery and Reinvestment Act of 2009. The Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law on October 3, 2008. The principal parts of the 2008 Act are: (1) a $700 billion financial markets stabilization plan; and (2) $150 billion in tax benefits, which are partially offset by $40 billion in revenue raisers. As part of its energy and conservation related incentives, the 2008 Act allows public utility property to qualify for the energy credit for periods after February 13, 2008 and extends the credit for solar energy property, fuel cell property and microturbine property through December 31, 2016. In addition, the 2008 Act allows the credit for combined heat and power (CHP) system property as energy property for periods after October 3, 2008. Further, the 2008 Act extends the renewable production credit through December 31, 2009 for qualified wind and refined coal production facilities and through December 31, 2010 for other sources. The 2008 Act also provides for a 10-year accelerated depreciation period for smart electric meters

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and smart electric grid equipment for property placed in service after October 3, 2008. Finally, the 2008 Act extends the per-gallon incentives for biodiesel and alternative fuels through December 31, 2009. The tax provisions of the 2008 Act did not have a material effect on the Company s results of operations for 2008. These tax provisions, however, may influence the Company s decisions to invest in the various properties entitled to credits and favorable depreciation. The Company will continue to analyze the 2008 Act for its impacts on results of operations, financial condition and liquidity and for the opportunities it presents.

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

The extension through 2009 of bonus depreciation, as originally provided in the 2008 Economic Stimulus Act, has the most direct and immediate impact on the Company. Although not quantified, the additional tax depreciation deduction will increase deferred income taxes and provide positive cash flow. The energy related provisions of the 2009 Act may impact utility operations indirectly. Some of the energy incentives are as follows: (1) a 30% tax credit of up to $1,500 for the purchase of highly efficient residential air conditioners, heat pumps or furnaces, (2) $0.3 billion in rebates for purchases of efficient appliances, (3) $20 billion for green jobs to make wind turbines and solar panels and to improve energy efficiency in schools and federal buildings, (4) $6 billion in loan guarantees for renewable energy projects, (5) $5 billion to help low-income homeowners make energy improvements, (6) $11 billion to modernize and expand the U.S. electric power grid, (7) $2 billion for research into batteries for future electric cars and (8) the extension of existing energy incentives and the addition of a few new ones. Finally, the 2009 Act temporarily eliminates the alternative minimum tax preference item for private activity bond interest for bonds (such as special purpose revenue bonds issued by HECO and its subsidiaries) issued in 2009 and 2010, including the $150 million of special purpose revenue bonds issued for the benefit of HECO and HELCO on July 30, 2009. This favorable change may influence the utilities decision to participate in issuances of additional bonds before the end of 2010.

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

Retirement benefits. 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. Assets were $1.1 billion at December 31, 2007, the fiscal year end prior to the 2008 market downturn.

Additional guidance on funding relief for qualified defined benefit pension plans was received in March 2009 including: (1) IRS Notice 2009-22 related to the application of new asset valuation rules included in the Worker, Retiree, and Employer Recovery Act of 2008 and (2) publication of a Special Edition March 2009 employee plans news related to yield curve selection for the target liability calculation. As a result, the Company estimates that the cash funding for the qualified defined benefit pension plans in 2009 and 2010 will be about $16 million and $48 million, respectively, which should fully satisfy the minimum required contribution, including requirements of the utilities pension tracking mechanisms and the Plan s funding policy. Prior to the March 2009 funding relief measures, cash funding to satisfy the minimum required contribution in 2009 and 2010 was estimated to be $21 million and $64 million, respectively. Additional guidance on minimum required contribution determinations for 2010 was released in Special Edition September 25, 2009 employee plans news necessitating selection of a different yield curve for 2010 valuations forward from what was used for 2009. This guidance does not change the estimate of 2010 contribution levels available at this time.

Other factors could cause changes to the required contribution levels. The Pension Protection Act provides that if a pension plan s funded status falls below certain levels, more conservative assumptions must be used to value obligations and restrictions on participant benefit accruals may be placed on the plans.

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

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

Other segment

(in thousands)	Three months ended September 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ (74)	$ (32)	NM	
Operating loss	(3,222)	(2,410)	NM	Higher expenses due to lower charges to subsidiaries
Net loss	(4,354)	(4,056)	NM	See explanation for operating loss and lower tax benefits, partly offset by lower interest expense (due to lower short-term borrowings in 2009 after the common stock sale in December 2008)

(in thousands)	Nine months ended September 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ (121)	$ (164)	NM	Lower unrealized losses on venture capital investments
Operating loss	(9,368)	(8,812)	NM	Higher expenses due to lower charges to subsidiaries
Net loss	(13,010)	(13,453)	NM	See explanation for operating loss and lower tax benefits, more than offset by lower interest expense (due to lower short-term borrowings in 2009 after the common stock sale in December 2008)

NM Not meaningful.

The other business segment includes results of operations of HEI and American Savings Holdings, Inc., holding companies; HEI Investments, Inc. (HEIII), a company previously holding investments in leveraged leases; Pacific Energy Conservation Services, Inc., a contract services company primarily providing wind farm operational and maintenance services to an affiliated electric utility; HEI Properties, Inc., a company holding passive, venture capital investments; The Old Oahu Tug Service, Inc., a maritime freight transportation company that ceased operations in 1999; and eliminations of intercompany transactions. Since HEIII sold all of its leveraged lease investments by the end of 2007, HEIII has filed articles of dissolution and is winding up its affairs.

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FINANCIAL CONDITION

Liquidity and capital resources

The Company believes that its ability to generate cash, both internally from electric utility and banking operations and externally from issuances of equity and debt securities, commercial paper and bank borrowings, is adequate to maintain sufficient liquidity to fund its contractual obligations and commercial commitments, its forecasted capital expenditures and investments, its expected retirement benefit plan contributions and other cash requirements in the foreseeable future.

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

(in millions)	September 30, 2009		December 31, 2008	
Short-term borrowings other than bank	$	%	$	%
Long-term debt, net other than bank	1,365	48	1,212	46
Noncontrolling interest: cumulative preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,422	51	1,389	53
	$ 2,821	100%	$ 2,635	100%

As of October 27, 2009, the Standard & Poor s (S&P) and Moody s Investors Service s (Moody s) ratings of HEI securities were as follows:

	S&P	Moody s
Commercial paper	A-3	P-2
Senior unsecured debt	BBB	Baa2

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

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

The rating agencies use a combination of qualitative measures (e.g., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HEI securities. In May 2009, S&P revised HEI s outlook to negative from stable, and lowered its commercial paper rating to A-3 from A-2 . S&P indicated the rating actions reflected its view that the next two years are likely to be challenging for HEI s electric utilities, which HEI relies on for cash flows to service its own obligations, chiefly debt repayment and common stock distributions. S&P stated that the deterioration in the Hawaii economy is likely to weaken 2009 and 2010 consolidated metrics, which it observed have been only marginally supportive of the BBB corporate credit ratings currently assigned to HEI.

S&P designates business risk profiles as excellent, strong, satisfactory, fair, weak or vulnerable. S&P s financial risk designations are m modest, intermediate, significant, aggressive and highly leveraged. In October 2009, S&P listed HEI s business risk profile as strong and financial risk profile as significant.

On July 20, 2009, Moody s issued a news release in which it indicated it had changed HEI s rating outlook to negative from stable and affirmed HEI s long-term and short-term (commercial paper) ratings. Moody s indicated that the rating affirmation reflects the fact that notwithstanding the issues outlined in the release, HEI s financial metrics are reasonably positioned in its rating category. See discussion below regarding the negative outlook.

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

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

Information about HEI s short-term borrowings and line of credit facility was as follows:

	Nine months ended September 30, 2009		
(in millions)	Average balance	End-of-period balance	December 31, 2008
Short-term borrowings [1]			
HEI commercial paper	$	$	$
HEI line of credit draws			
Line of credit facility (expiring March 31, 2011) [1]		$ 100	$ 100
Undrawn capacity under HEI s line of credit facility [2]		100	100

1 In the future, the Company may seek to enter into new lines of credit and may also seek to increase the amount of credit available under such lines as management deems appropriate. This table does not include HECO s separate commercial paper issuances and line of credit facilities and draws.

2 At October 27, 2009, there was no outstanding commercial paper balance and the line of credit facility was undrawn.

HEI utilizes short-term debt, typically commercial paper, to support normal operations, to refinance commercial paper, to retire long-term debt and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO s cash requirements, including the funding of loans by HECO to HELCO and MECO. As of September 30, 2009, HEI had no short-term borrowings outstanding and had short-term loans to HECO of $10.7 million. HEI expects to contribute approximately $100 million of equity to HECO by December 31, 2009 and thus will require short-term borrowings in the fourth quarter of 2009. Since HEI s commercial paper rating has been downgraded to A-3/P-2, management believes that it will access the commercial paper market at higher prices and shorter maturities, or access may be unreliable. Such limitations could cause HEI to draw on its syndicated credit facility instead. Management believes that if HEI s commercial paper ratings were to be further downgraded, or if credit markets for commercial paper with HEI s ratings or otherwise were to further tighten, it would be even more difficult and expensive to sell commercial paper or it might not be able to sell commercial paper in the future.

In November 2008, HEI filed an omnibus registration statement to register an indeterminate amount of debt, equity and hybrid securities. Under Securities and Exchange Commission (SEC) regulations, this registration statement expires on November 4, 2011. On December 2, 2008, HEI offered and priced under the registration a public offering of 5,000,000 shares of its common stock at $23 per share for gross proceeds of $115 million. HEI used the net proceeds of approximately $110 million, after deduction of underwriting discounts and commissions and estimated HEI expenses, to repay its outstanding short-term indebtedness, to make loans to HECO and for working capital and other general corporate purposes. An over-allotment option granted to the underwriters was not exercised.

Issuances of common stock through the Hawaiian Electric Industries, Inc. Dividend Reinvestment and Stock Purchase Plan (DRIP) and the Hawaiian Electric Industries Retirement Savings Plan (HEIRS) have been important sources of capital for HEI. Issuances of common stock through DRIP and HEIRS provided new capital of $43 million (approximately 1.8 million shares) in 2008 and $41 million (approximately 1.7 million shares) in 2007. From January 1, 2009 through April 15, 2009, issuances of common stock through these plans increased significantly. During this period, HEI raised $14 million of new capital through the issuance of approximately 1.0 million shares for these plans.

HEI ceased such issuances of stock through DRIP and HEIRS effective April 16, 2009 and began satisfying the HEI common stock requirements of DRIP and HEIRS through open market purchases. Also, since inception on May 7, 2009, the current ASB 401(k) Plan has satisfied its HEI common stock requirements through open market

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purchases. On September 4, 2009, HEI resumed satisfying the HEI common stock requirements of DRIP, HEIRS and the ASB 401(k) Plan through issuances of new common stock and raised $8 million of new capital through the issuance of approximately 0.5 million shares for these plans in September 2009.

For the first nine months of 2009, net cash provided by operating activities of consolidated HEI was $227 million. Net cash provided by investing activities for the same period was $223 million, primarily due to net decreases in loans receivable and investment and mortgage-related securities at ASB, partly offset by HECO s consolidated capital expenditures. Net cash used in financing activities during this period was $374 million as a result of several factors, including net decreases in other bank borrowings, deposit liabilities and retail repurchase agreements and the payment of common stock dividends, partly offset by drawdown of SPRB proceeds and proceeds from the issuance of common stock under HEI plans.

For the first nine months of 2009, net cash used by operating activities of the other segment was $18 million. Net cash used by investing activities for the same period was $0.1 million, primarily due to capital expenditures. Net cash provided by financing activities during this period was $39 million primarily due HECO s repayment of borrowings from HEI and proceeds from the issuance of common stock, partly offset by payment of common stock dividends.

Forecasted HEI consolidated net cash used in investing activities (excluding investing cash flows from ASB) for 2009 through 2011 consists primarily of the net capital expenditures of HECO and its subsidiaries. In addition to the funds required for the electric utilities construction program, approximately $150 million will be required in 2011 to repay maturing HEI medium-term notes, which are expected to be repaid with the proceeds from the issuance of commercial paper, bank borrowings, common stock issued under Company plans and/or dividends from subsidiaries. Additional debt and/or equity financing may be utilized to pay down commercial paper or other short-term borrowings or may be required to fund uncertain or unanticipated expenditures not included in the 2009 through 2011 forecast, such as increases in the costs of or an acceleration of the construction of capital projects of the utilities, utility capital expenditures that may be required by the HCEI or new environmental laws and regulations, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements and higher tax payments that would result if certain tax positions taken by the Company do not prevail. In addition, existing debt may be refinanced prior to maturity (potentially at more favorable rates) with additional debt or equity financing (or both).

The Company was not required to make any contributions to the qualified pension plans to meet minimum funding requirements pursuant to ERISA for 2008, but made voluntary contributions in 2008. Contributions to the retirement benefit plans totaled $15 million in 2008 (comprised of $14 million made by the utilities, $1 million by HEI and nil by ASB) and are expected to total $25 million in 2009 ($24 million by the utilities, $1 million by HEI and nil by ASB). Depending on the performance of the assets held in the plans trusts and numerous other factors, additional contributions may be required in the future to meet the minimum funding requirements of ERISA or to pay benefits to plan participants. Although credit markets have tightened and may tighten further, the Company believes it will have adequate access to capital resources to support any necessary funding requirements.

CERTAIN FACTORS THAT MAY AFFECT FUTURE RESULTS AND FINANCIAL CONDITION

The Company s results of operations and financial condition can be affected by numerous factors, many of which are beyond the Company s control and could cause future results of operations to differ materially from historical results. For information about certain of these factors, see pages 12 to 13, 39 to 44, and 53 to 55 of HEI s MD&A, which is filed in HEI Exhibit 99.1 to HEI s Form 8-K dated June 9, 2009.

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

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MATERIAL ESTIMATES AND CRITICAL ACCOUNTING POLICIES

In preparing financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses. Actual results could differ significantly from those estimates.

In accordance with SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, management has identified the accounting policies it believes to be the most critical to the Company s financial statements that is, management believes that these policies are both the most important to the portrayal of the Company s financial condition and results of operations, and currently require management s most difficult, subjective or complex judgments.

For information about these material estimates and critical accounting policies, see pages 13 to 14, 44 to 45, and 56 of HEI s MD&A, which is filed in HEI Exhibit 99.1 to HEI s Form 8-K dated June 9, 2009.

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

Electric utility

RESULTS OF OPERATIONS

(dollars in thousands, except per barrel amounts)	Three months ended September 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 548,440	$ 827,788	(34)	Lower fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers ($275 million), lower KWH sales ($8 million) and lower DSM costs recovered through a surcharge ($8 million), offset in part by HECO test year 2009 interim rate relief ($10 million)
Expenses				
Fuel oil	186,719	377,157	(50)	Lower fuel oil costs and less KWHs generated
Purchased power	134,447	202,125	(33)	Lower fuel costs and less KWHs purchased
Other operation	61,173	61,599	(1)	See Results three months ended September 30, 2009 below
Maintenance	25,968	25,174	3	See Results three months ended September 30, 2009 below
Depreciation	35,557	35,419		
Taxes, other than income taxes	50,031	74,201	(33)	Decrease in revenues
Other	373	266	40	
Operating income	54,172	51,847	4	Interim rate relief, partly offset by lower sales and higher maintenance expense
Net income for common stock	26,514	25,932	2	Higher operating income and AFUDC
Kilowatthour sales (millions)	2,572	2,593	(1)	Slowing economy and customer conservation, partly offset by warmer weather
Cooling degree days (Oahu)	1,588	1,530	4	
Average fuel oil cost per barrel	$ 66.40	$ 133.99	(50)	

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(dollars in thousands, except per barrel amounts)	Nine months ended September 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 1,460,654	$ 2,139,798	(32)	Lower fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers ($609 million), lower KWH sales ($83 million) and lower DSM costs recovered through a surcharge ($6 million), partly offset by HECO test year 2009 interim rate relief ($10 million)
Expenses				
Fuel oil	463,893	900,455	(48)	Lower fuel oil costs and less KWHs generated
Purchased power	364,120	530,146	(31)	Lower fuel costs and less KWHs purchased
Other operation	186,751	176,600	6	See Results nine months ended September 30, 2009 below
Maintenance	81,562	72,777	12	See Results nine months ended September 30, 2009 below
Depreciation	108,406	106,254	2	Additions to plant in service in 2008
Taxes, other than income taxes	137,741	194,058	(29)	Decrease in revenues
Other	777	1,282	(39)	
Operating income	117,404	158,226	(26)	Lower sales and higher other operation and maintenance (O&M) and depreciation expenses, partly offset by interim rate relief
Net income for common stock	56,141	77,949	(28)	Lower operating income, partly offset by higher AFUDC
Kilowatthour sales (millions)	7,203	7,478	(4)	Slowing economy, customer conservation and cooler, less humid weather on Oahu
Cooling degree days (Oahu)	3,591	3,779	(5)	
Average fuel oil cost per barrel	$ 59.21	$ 111.37	(47)	

Note: The electric utilities had an effective tax rate for the third quarters of 2009 and 2008 of 37% and 36%, respectively. The electric utilities had an effective tax rate for the first nine months of 2009 and 2008 of 37%.

See Economic conditions in the HEI Consolidated section above.

Results three months ended September 30, 2009. Operating income for the third quarter of 2009 increased 4% from the same period in 2008 due primarily to $10 million of interim rate relief granted by the PUC to HECO (2009 test year) effective August 2009, partially offset by lower sales and higher maintenance expenses. For the third quarter of 2009, kilowatthour (KWH) sales were down 0.8% compared with the same quarter of 2008, primarily due to the soft economy and ongoing customer conservation, partly offset by the impact of warmer and more humid weather.

Other operation expenses for the third quarter of 2009 decreased by $0.4 million over the same period in 2008, primarily due to lower DSM expenses (see Demand-side management programs below) that are generally passed on to customers through surcharges ($7.0 million), partly offset by higher retirement benefits expense ($2.0 million), a retrospective medical plan premium adjustment ($1.8 million), higher planned production and transmission and distribution operations expense to maintain reliable operations ($2.2 million, including expenses for HECO s CIP CT-

1) and expenses to pursue renewable initiatives. Retirement benefit expenses increased due to a higher discount rate, lower projected long-term asset return rate and amortization of deferred expenses related to the PUC tracking mechanism (see Note 4 of HECO s Notes to Consolidated Financial Statements). Maintenance expense increased $0.8 million, primarily due to higher substation maintenance, vegetation management and underground line maintenance expenses, partially offset by lower generating unit overhaul expenses.

Increased O&M expenses are expected to continue as the electric utilities expect higher production expenses (primarily due to increased utilization of HECO s generating assets commensurate with the level of demand that has occurred over the past five years), higher contract services costs, and higher transmission and distribution expenses to maintain system reliability. Also, additional expenses are expected to be incurred for the costs of CIP CT-1, for environmental compliance in response to more stringent regulatory requirements, and to execute the provisions of the Energy Agreement. Partly offsetting the anticipated increased costs are lower DSM expenses (that are generally passed on to customers through a surcharge) due to the transition of energy efficiency programs to a third-party administrator in July 2009 and the impact of cost containment measures. The utilities now expect O&M for 2009 to increase by approximately 6% compared with 2008 with no significant change in DSM expenses between the third and fourth quarters of 2009. Due to the current economic challenges and management s efforts to prudently manage costs, the utilities are deferring HCEI expenditures that are not time-critical. However, the utilities continue to fund time-critical initiatives in order to maintain momentum in achieving the state s clean energy goals.

Although peak demand moderated in 2008, generation reserve margins on Oahu continued to be strained. HECO has taken a number of steps to mitigate the risk of outages, including securing additional purchased power, adding DG at some substations, completing all utility requirements for system operation for CIP CT-1 on August 3, 2009 and encouraging energy conservation. The costs of supplying energy to meet high demand and the maintenance costs required to sustain high availability of the aging generating units have been increasing and the increased costs are likely to continue.

Results nine months ended September 30, 2009. Operating income for the first nine months of 2009 decreased 26% from the same period in 2008 due primarily to lower sales and higher O&M expenses, partially offset by $10 million of interim rate relief granted by the PUC to HECO (2009 test year) effective August 2009. For the first nine months of 2009, KWH sales were down 3.7% compared to the same period in 2008. The decline in sales is attributable to the soft economy and ongoing customer conservation.

Other operation expenses increased by $10.2 million in the first nine months of 2009 compared to the same period in 2008, primarily due to higher planned production and transmission and distribution operations expense to maintain reliable operations and pursue renewable initiatives ($5.5 million) and higher retirement benefits expense ($2.0 million) and a retrospective medical plan premium adjustment ($1.8 million). Maintenance expense increased $8.8 million, primarily due to the greater number and scope of generating unit overhauls and higher expenses for overhead and underground line maintenance, vegetation management and substation maintenance.

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

In its June 30, 2009 filing with the PUC, HECO reported a consolidated RPS of 18% in 2008. This was accomplished through a combination of municipal solid waste, geothermal, wind, biomass, hydro, photovoltaic and biodiesel renewable generation resources; renewable energy displacement technologies; and energy savings from efficiency technologies.

The electric utilities are actively exploring the use of biofuels for existing and planned company-owned generating units. HECO has committed to using 100% biofuels for its new 110 MW generating unit. HECO is researching the possibility of switching its steam generating units from fossil fuels to biofuels, and in the Energy Agreement has committed to do so if economically and technically feasible and if adequate biofuels are available. In July 2009, HECO and MECO submitted separate applications with the PUC to approve biodiesel supply contracts for their respective biodiesel demonstration projects, and to include the biodiesel fuel costs and related costs in their respective energy cost adjustment clauses. HECO s application also requested approval of capital project costs, but MECO s estimated capital project costs were below the threshold that required separate PUC approval.

In January 2007, HECO and MECO agreed to form a venture with BlueEarth Biofuels LLC (BlueEarth) to develop a biodiesel production facility on MECO property on the island of Maui. BlueEarth Maui Biodiesel LLC (BlueEarth Maui), a joint venture to pursue biodiesel development, was formed in early 2008 between BlueEarth and Uluwehiokama Biofuels Corp. (UBC), a non-regulated subsidiary of HECO. In February 2008, an Operating Agreement and an Investment Agreement were executed between BlueEarth and UBC, under which UBC invested $400,000 in BlueEarth Maui in exchange for a minority ownership interest. MECO began negotiating with BlueEarth Maui for a fuel purchase contract for biodiesel to be used in existing diesel-fired units at MECO s Maalaea plant. However, negotiations for the biodiesel supply contract stalled based on an inability to reach agreement on various financial and risk allocation issues. In October 2008, BlueEarth filed a civil action in federal district court in Texas against MECO, HECO and others alleging claims based on the parties failure to have reached agreement on the biodiesel supply and related land agreements. The lawsuit seeks damages and equitable relief. In April 2009, the venue of the action was transferred to Hawaii. A trial date has been scheduled for June 2010. Work on the project was suspended because the litigation was filed. The Memorandum of Understanding (MOU) between HECO, MECO and BlueEarth regarding the project has also expired. Although HECO remains committed to supporting development of renewable fuels production, because of the filing of the litigation, the expiration of the MOU, and other factors, HECO and MECO now consider the project terminated.

The electric utilities also support renewable energy through solar water heating and heat pump programs, and the negotiation and execution of purchased power contracts with non-utility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric, photovoltaic and wind turbine generating systems). In November 2007, HECO entered into a contract with Hoku Solar, Inc. to purchase energy from a photovoltaic system with a generating capacity of up to 300 kilowatts (kW) to be located at HECO s Archer Substation. The PUC approved the contract in May 2008, and the project is scheduled to be in service on December 16, 2009, which date may be extended. In November 2008, the PUC approved a power purchase contract between MECO and Lanai Sustainability Research, LLC for the purchase of up to 1.2 MW of electricity from a photovoltaic system owned by Lanai Sustainability Research, LLC, which was placed in service in December 2008. In December 2008, the PUC approved a power purchase contract between HELCO and Keahole Solar Power LLC (a wholly-owned subsidiary of Sopogy, Inc.) for the purchase of energy from a 500 kW concentrated solar power facility, which is now being installed. In March 2009, HECO and HELCO filed an executed term sheet with the PUC for a power purchase contract with Hu Honua Bioenergy, LLC, which intends to refurbish a biomass plant located on the island of Hawaii. In July 2009, HECO executed a purchase power agreement with Kahuku Wind Power, LLC, subject to PUC approval, to purchase 30 MW of electricity from a wind turbine generating system, and in August 2009 HECO filed an application requesting PUC approval of the agreement.

On April 30, 2009, HECO filed an application with the PUC for approval of a Photovoltaic (PV) Host Pilot Program. If approved, this will be a two-year pilot program whereby HECO, HELCO and MECO would lease rooftops or other space from property owners, with a focus on governmental facilities, for third-party owned photovoltaic systems. The PV developer would own, operate and maintain the system and sell the energy to the utilities at a fixed rate under a long term contract. The procedural schedule begins with a technical session in November 2009 and ends with the filing of HECO s Reply Statement of Position in June 2010.

In September 2007, HECO issued a Solicitation of Interest for its planned Renewable Energy Request for Proposals (RFP) for combined renewable energy projects up to 100 MW on Oahu. In June 2008, the PUC approved HECO s Oahu Renewable Energy RFP and HECO issued the RFP shortly thereafter. An Award Group of bidders has been selected and notified. The RFP schedule provides for submittal of PPAs for PUC approval by December 2009. Included in the bids received were proposals for large scale neighbor island wind projects. In accordance with the Energy Agreement, the proposals for large scale neighbor island wind projects (Big Wind projects) were bifurcated from the Oahu Renewable Energy RFP. The utilities intend to separately negotiate

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purchase power agreements with two neighbor island wind projects that would produce energy to be imported to Oahu via a yet-to-be-built undersea transmission cable system.

On July 17, 2009, HECO filed an application requesting approval to (1) to defer the costs of outside services incurred in 2009 and 2010 to conduct the studies and analyses necessary (a) to reliably and effectively integrate large amounts of wind-generated renewable energy potentially located on the islands of Molokai and Lanai to the Oahu electric grid, and (b) to assess the potential routes and permitting requirements for the Oahu transmission lines and facilities necessary to interconnect undersea cables delivering power from the Big Wind Projects to Oahu; and (2) to recover the expenses for these Big Wind Implementation Studies through a surcharge mechanism. The specific approvals requested included approvals (1) to defer the costs for outside services (estimated at $6.3 million) for the Big Wind Implementation Studies that are expected to be incurred from January 1, 2009 through 2010, and that would otherwise be expensed; and (2) to recover the revenue requirements of those deferred costs through the Renewable Energy Infrastructure Program/Clean Energy Infrastructure Surcharge (REIP/CEI Surcharge) that is pending approval or, in the alternative, through a Big Wind Project-specific surcharge (Big Wind Surcharge) mechanism that the PUC would approve in this proceeding. If the PUC does not approve recovery of the Big Wind Implementation Studies expenses through a surcharge mechanism, HECO requested PUC approval (1) to defer the Big Wind Implementation Studies costs beginning January 1, 2009 until its next rate case, (2) to amortize the deferred costs over a three-year period beginning when rates established in the next rate case that reflect the amortization become effective, (3) to include the annual amortization expense in determining the revenue requirements in that next rate case, and (4) to include the unamortized balance of the deferred costs in rate base to determine HECO s revenue requirement. The PUC entered a procedural order in the docket on September 23, 2009.

HECO s unregulated subsidiary, Renewable Hawaii, Inc. (RHI), was established to stimulate renewable energy initiatives by prospecting for new projects and sites and taking a passive, minority interest in selected third-party renewable energy projects. Beginning in 2003, RHI actively pursued a number of projects, particularly those utilizing wind, landfill gas, and ocean energy. While RHI has executed some memoranda of understanding and conditional investment agreements with project developers, no investments have been made to date. Due to the active renewable energy marketplace in Hawaii, RHI is not seeking new projects at this time.

The electric utilities promote research and development in the areas supporting renewable energy such as biofuels, ocean energy, battery storage, smart grids, and integration of non-firm power into the separate island electric grids.

Energy efficiency and DSM programs for commercial and industrial customers, and residential customers, including load control programs, have resulted in reducing system peak load and contribute to the achievement of the RPS. Since the inception of the energy efficiency and DSM programs in 1996 and through the end of 2008, the total system peak load has been reduced by 163 MW (143 MW at HECO, 8 MW at HELCO, and 12 MW at MECO) at the gross generation level and net of estimated reductions from participants who would have installed the DSM measure without the program and rebate.

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

Also, see Renewable Portfolio Standard under Legislation and regulation below.

Competition. Although competition in the generation sector in Hawaii has been moderated by the scarcity of generation sites, various permitting processes and lack of interconnections to other electric utilities, HECO and its subsidiaries face competition from IPPs and customer self-generation, with or without cogeneration.

In 1996, the PUC issued an order instituting a proceeding to identify and examine the issues surrounding electric competition and to determine the impact of competition on the electric utility infrastructure in Hawaii. In October 2003, the PUC opened investigative proceedings on two specific issues (competitive bidding and DG) to move toward a more competitive electric industry environment under cost-based regulation. For a description of some of the regulatory changes that will be pursued as part of the Energy Agreement, see Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements.

Competitive bidding proceeding. The stated purpose of this proceeding, commenced in 2003, was to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii. In December 2006, the PUC issued a decision that included a final competitive bidding framework, which became effective immediately. The final framework states, among other things, that under the framework: (1) a utility is required to use competitive bidding to acquire a future generation resource or a block of generation resources unless the PUC finds bidding to be unsuitable; (2) the determination of whether to use competitive bidding for a future generation resource or a block of generation resources will be made by the PUC during its review of the utility s IRP; (3) the framework does not apply to three pending projects, specifically identified offers to sell energy on an as-available basis or to sell firm energy and/or capacity by non-fossil fuel producers and certain other situations identified in the framework; (4) waivers from competitive bidding for certain circumstances will be considered by the PUC; (5) for each project that is subject to competitive bidding, the utility is required to submit a report on the cost of parallel planning upon the PUC s request; (6) the utility is required to consider the effects on competitive bidding of not allowing bidders access to utility-owned or controlled sites, and to present reasons to the PUC for not allowing site access to bidders when the utility has not chosen to offer a site to a third party; (7) the utility is required to select an independent observer from a list approved by the PUC whenever the utility or its affiliate seeks to advance a project proposal (i.e., in competition with those offered by bidders); (8) the utility may consider its own self-bid proposals in response to generation needs identified in its RFP; (9) the evaluation of the utility s bid should account for the possibility that the capital or running costs actually incurred, and recovered from ratepayers, over the plant s lifetime, will vary from the levels assumed in the utility s bid; and (10) for any resource to which competitive bidding does not apply (due to waiver or exemption), the utility retains its traditional obligation to offer to purchase capacity and energy from a Qualifying Facility (QF) at avoided cost upon reasonable terms and conditions approved by the PUC.

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

In June 2008, HECO issued a RFP, which seeks proposals for the supply of up to approximately 100 MW of long-term renewable energy for the island of Oahu under a PPA. An Award Group of bidders has been selected and notified. The RFP schedule provides for submittal of PPAs for PUC approval by December 2009. The Energy Agreement recognized that the Oahu Renewable Energy RFP provides an excellent near-term opportunity to add new clean renewable energy sources on Oahu and included the anticipated up to 100 MW of renewable energy from these project proposals in its goals. See Renewable energy strategy above for a discussion on the bifurcation of the large-scale neighbor island wind project proposals from the other proposals received in response to the Oahu Renewable Energy RFP.

In December 2007, in response to MECO s request for approval to proceed with a competitive bidding process to acquire two separate increments of approximately 20 MW to 25 MW of firm generating capacity on the island of Maui in the 2011 and 2015 timeframes, the PUC opened a new docket related to MECO s proposed RFP. Subsequently, MECO filed an updated Adequacy of Supply Report and informed the PUC that due to lower loads, the need date for new firm capacity resources is now in the 2021 timeframe. Based on this development, in October 2009, MECO requested that the PUC close the proceeding related to MECO s RFP.

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

In the third and fourth quarters of 2008, the PUC granted requests for waivers from the Competitive Bidding Framework for five projects. The waivers for four of the five projects subsequently expired without reaching agreement on a term sheet. Discussions on the fifth waivered project continued. HECO and HELCO then proposed a competitive bidding process to acquire renewable generation on the island of Hawaii.

In March 2009, HELCO reached agreement on a term sheet with the remaining waivered biomass project. Since this term sheet agreement would have an effect on the proposed competitive bidding process, HELCO retained an Independent Engineering consultant to evaluate the suitability of the current generation system conditions for issuing an RFP for acquiring additional renewable resources. In June 2009, the Independent Engineer recommended that HELCO not proceed with an RFP at this time and instead conduct further analyses to determine what resource attributes would be most beneficial to the HELCO system and then assess how best to acquire those resources. Those analyses are currently being performed by HELCO.

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

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

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

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

The January 2006 D&O also required the utilities to file tariffs and establish standby rates based on unbundled costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services). The utilities filed their proposed modifications to existing DG interconnection tariffs and their proposed unbundled standby rates for PUC approval in the third quarter of 2006. The Consumer Advocate stated that it did not object to implementation of the interconnection and standby rate tariffs at that time, but reserved the right to review the

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reasonableness of both tariffs in rate proceedings for each of the utilities. See Distributed generation tariff proceeding below.

In April 2006, the PUC provided clarification to the conditions under which the utilities are allowed to provide regulated DG services (e.g., the utilities can use a portfolio perspective a DG project aggregated with other DG systems and other supply-side and demand-side options to support a finding that utility-owned, customer-sited DG projects fulfill a legitimate system need, and the economic standard of least cost in the order means lowest reasonable cost consistent with the standard in the IRP framework). The PUC also affirmed that the electric utility has the responsibility to demonstrate that it meets all applicable criteria included in the D&O in its application for PUC approval to proceed with a specific DG project.

The utilities are developing or evaluating potential DG projects. In September 2008, HECO executed an agreement with the State of Hawaii Department of Transportation to develop a dispatchable standby generation (DSG) facility at the Honolulu Airport that will be owned by the State and operated by HECO. The D&O encouraged HECO to pursue such DG operating arrangements with customers. HECO filed an application to the PUC for approval of the agreement in December 2008.

By a D&O issued in June 2009, the PUC approved the agreement for the DSG facility at the Honolulu International Airport. The PUC also approved HECO s request to waive the project from the Competitive Bidding Framework and HECO s commitment of funds. However, the PUC denied HECO s proposed accounting and ratemaking treatment for capital and overhaul reimbursement payments to be made by HECO to the Department of Transportation under the terms of the agreement. HECO and the Department of Transportation amended the agreement to provide HECO with the ability to seek cost recovery for these expenses in accordance with the PUC D&O. HECO will submit the amended agreement to the PUC for approval.

HECO is also evaluating the potential to develop utility-owned DG at Oahu military bases, in a manner consistent with the D&O, in order to meet utility system needs and the energy objectives of the DOD. In 2009, HECO will conduct a feasibility review of extending the use of temporary DG units that were installed at various HECO substations in 2005 to 2007 and converting them to run on biodiesel.

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

Distributed generation tariff proceeding. In December 2006, the PUC opened a new proceeding to investigate the utilities proposed DG interconnection tariff modifications and standby rate tariffs. In March 2008, the parties to the proceeding filed a settlement agreement with the PUC proposing that a standby service tariff agreed to by the parties should be approved. The interconnection tariffs, with modifications made in response to the PUC s information requests, were approved in April 2008. In May 2008, the PUC approved the settlement agreement on the standby service tariff.

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

As required in the Energy Agreement, the utilities conducted a review of the modified DG interconnection tariffs to evaluate whether the tariffs are effective in supporting non-utility DG and distributed energy storage by improving the process and procedure for interconnection. HECO filed its evaluation report to the PUC in June 2009, concluding that the process has been working efficiently. Several minor modifications to clarify portions of the tariff were identified. A request to modify the DG interconnection tariff will be filed with the PUC later in 2009.

DG and distributed energy storage under the Energy Agreement. Under the Energy Agreement, the utilities committed to facilitate planning for distributed energy resources through a new Clean Energy Scenario Planning process. Under this process, Locational Value Maps will be developed by December 31, 2009 to identify areas where DG and distributed energy storage would provide utility system benefits and can be reasonably accommodated.

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

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

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

The Energy Agreement also provides that to the degree that transmission and distribution automation and other smart grid technology investments are needed to facilitate distributed energy resource utilization, those investments will be recovered through a Clean Energy Infrastructure Surcharge and later placed in rate base in the next rate case proceeding.

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

As of October 27, 2009, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 10.7% for HECO (D&O issued on May 1, 2008, based on a 2005 test year), 11.5% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). The ROACEs used by the PUC in the interim rate increases in HECO, HELCO and MECO rate cases based on 2009, 2006 and 2007 test years issued in August 2009, April 2007 and December 2007, were 10.5%, 10.7% and 10.7% respectively.

For the 12 months ended September 30, 2009, the actual ROACEs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 6.52%, 6.17% and 4.74%, respectively. HECO s actual ROACE was 398 basis points lower than its interim D&O ROACE primarily due to lower KWH sales and increased O&M expenses, which are expected to continue. HELCO and MECO s actual ROACEs were 453 and 596 basis points, respectively, lower than their interim D&O ROACEs due in part to lower KWH sales.

As of October 27, 2009, the return on rate base (ROR) found by the PUC to be reasonable in the most recent final rate decision for each utility was 8.66% for HECO, 9.14% for HELCO and 8.83% for MECO (D&Os noted above). The RORs used by the PUC for purposes of the interim D&Os in the HECO, HELCO and MECO rate cases based on 2009, 2006 and 2007 test years were 8.45%, 8.33% and 8.67%, respectively. For the 12 months ended September 30, 2009, the actual RORs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 5.36%, 4.92% and 4.87%, respectively.

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

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

HECO.

2005 test year rate case. In November 2004, HECO filed a request with the PUC to increase base rates, based on a 2005 test year, a 9.11% ROR and an 11.5% ROACE. Disregarding an amount included in the request to transfer the cost of existing DSM programs from a surcharge line item on electric bills into base electricity charges, which issue was bifurcated for consideration in another proceeding, the requested base rates increase was $74 million, or 7.3%.

In September 2005, HECO, the Consumer Advocate and the DOD reached agreement (subject to PUC approval) on most of the issues in the rate case proceeding. The significant issue not resolved among the parties was the appropriateness of including in rate base approximately $50 million related to HECO s prepaid pension asset, net of deferred income taxes.

Later in September 2005, the PUC issued its interim D&O, authorizing an increase of $53 million ($41 million net additional revenues). For purposes of the interim D&O, the PUC included HECO s prepaid pension asset in rate base (with an annual rate increase impact of approximately $7 million).

On October 25, 2007, the PUC issued an amended proposed final D&O, authorizing a net increase of 2.7%, or $34 million, in annual revenues, based on a 10.7% ROACE (and an 8.66% ROR on a rate base of $1.060 billion). The amended proposed final D&O, which was issued in final form with certain modifications (as described below), reversed the portion of the interim D&O related to the inclusion of HECO s approximately $50 million pension asset, net of deferred income taxes, in rate base, and required a refund of revenues associated with that reversal, including interest, retroactive to September 28, 2005 (the date the interim increase became effective).

On May 1, 2008, the PUC issued the final D&O for HECO s 2005 test year rate case, which was consistent with a stipulated revised results of operations filed by the parties on March 28, 2008, and authorized an increase of $45 million in annual revenues ($34 million net) based on a 10.7% ROACE (and an 8.66% ROR on a rate base of $1.060 billion). In the final D&O, the PUC accepted the parties position that the review of the ECAC under Act 162 (Hawaii Revised Statutes §269-16(g)) should not be required in this case, but would be made in HECO s 2007 test year rate case.

Following the issuance of the final D&O, the required refund, with interest, to customers was completed in August 2008. On October 2, 2008, HECO filed with the PUC its 2005 test year rate case refund reconciliation, which reflected that $1.4 million was over-refunded. On October 28, 2008, the PUC issued a letter stating that HECO was not authorized to collect the over-refunded amount and HECO reduced its revenues for the third quarter of 2008 by $1.4 million.

2007 test year rate case. On December 22, 2006, HECO filed a request with the PUC for a general rate increase of $99.6 million, or 7.1% over the electric rates currently in effect (i.e., over rates that included the interim rate increase discussed above of $53 million ($41 million net additional revenues) granted by the PUC in September 2005), based on a 2007 test year, an 8.92% ROR, an 11.25% ROACE and a $1.214 billion average rate base. This rate case excluded DSM surcharge revenues and associated incremental DSM costs because certain DSM issues, including cost recovery, were being addressed in another proceeding.

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

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

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

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

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

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

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

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

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

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

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

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

2009 test year rate case. On July 3, 2008, HECO filed a request for a general rate increase of $97 million or 5.2% over the electric rates currently in effect (i.e., over rates that included the interim rate increase discussed above granted by the PUC in HECO s 2007 test year rate case, which amount is $77 million based on the effects of the final decision in HECO s 2005 test year rate case), based on a 2009 test year, an 8.81% ROR, an 11.25% ROACE, and a $1.408 billion rate base. HECO s application requested an interim increase of $73 million on or before the statutory deadline for interim rate relief and a step increase of $24 million based on the return on the annualized net investment of the new CIP CT-1 and recovery of associated expenses to be effective at the in-service date of the new unit.

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

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

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

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

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

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identified by HECO in March 2009 relating to the replacement of HECO s customer information system. The DOD recommended a revenue increase of $45.1 million based on its proposed ROR of 7.85%, an ROACE of 9.50% and a proposed average rate base of $1.309 billion. The DOD also recommended an average rate base treatment for the CIP CT-1 and in its recommendations has removed the costs and expenses identified by HECO in March 2009 relating to the replacement of HECO s customer information system.

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

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

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

On July 2, 2009, the PUC issued an interim D&O in HECO s 2009 test year rate case proceeding. The interim D&O approved a rate increase for interim purposes, but directed that adjustments be made to reduce the increase reflected in HECO s statement of probable entitlement for several items, including certain labor expenses, and the costs related to CIP CT-1 (approximately $13 million of revenue requirements). Part of the labor expense reduction relates to new positions established to carry out initiatives included in the HCEI. The PUC removed certain costs related to HCEI, because those initiatives are still the subject of pending PUC proceedings and have not yet been approved. The PUC removed the costs related to CIP CT-1 from rate base indicating that the record did not yet demonstrate that the CIP CT-1 unit would be in service by the end of the 2009 test year. The PUC did not approve the proposal to establish an RBA to be effective as of the date of the interim D&O, pending the outcome of the decoupling proceeding.

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

On July 15, 2009, in responding to HECO s calculations, the Consumer Advocate stated that HECO s proposed adjustments were conservatively prepared, that HECO s revised schedules were in general compliance with the PUC s interim D&O, and that it did not object to HECO s filing. The Consumer Advocate also identified Hawaii Clean Energy Initiative (HCEI)-related costs of $1.5 million that were included in the settlement agreement and HECO s statement of probable entitlement that it believed could be subject to interpretation as to whether they should be included in the interim rate relief under the D&O. HECO filed a response providing an explanation supporting the inclusion of these costs in its original interim increase calculations. The DOD did not file any comments on HECO s interim increase calculations. The interim decision was implemented on August 3, 2009. If the amounts collected pursuant to an interim decision exceed the amount of the increase ultimately approved in the final D&O, then the excess would have to be refunded to HECO s customers, with interest.

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

As the PUC did not accept the material terms of the settlement agreement, any (and all) of the parties may withdraw from the agreement and pursue their respective positions at the hearing, but none of the parties have indicated an intention to do so. Management cannot predict the timing, or ultimate outcome, of a final D&O in this rate case.

HELCO.

2006 test year rate case. In May 2006, HELCO filed a request with the PUC to increase base rates by $29.9 million, or 9.24% in annual base revenues, based on a 2006 test year, an 8.65% ROR, an 11.25% ROACE and a $369 million average rate base. HELCO s application included a proposed new tiered rate structure, which would enable most residential users to see smaller increases in the range of 3% to 8%. The tiered rate structure was designed to minimize the increase for residential customers using less electricity and is expected to encourage customers to take advantage of solar water heating programs and other energy management options. In addition, HELCO s application proposed new time-of-use service rates for residential and commercial customers. The proposed rate increase would pay for improvements made to increase reliability, including transmission and distribution line improvements and the two generating units at the Keahole power plant (CT-4 and CT-5), and increased O&M expenses. The application requested the continuation of HELCO s ECAC.

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

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

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

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

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

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

2010 test year rate case. On July 17, 2009, HELCO filed a Notice of Intent to file an application for a general rate increase on or after November 25, 2009 (but before January 1, 2010).

MECO.

2007 test year rate case. In February 2007, MECO filed a request with the PUC to increase base rates by $19.0 million, or 5.3% in annual base revenues, based on a 2007 test year, an 8.98% ROR, an 11.25% ROACE and a $386 million average rate base. MECO s application included a proposed new tiered rate structure for residential customers to reward customers who practice energy conservation with lower electric rates for lower monthly usage. The proposed rate increase would pay for improvements to increase reliability, including two new generating units added since MECO s last rate case (which was based on a 1999 test year) at its Maalaea Power plant (M19, a 20 MW CT placed in service in 2000 and M18, an 18 MW steam turbine placed in service in October 2006 to complete the installation of a second dual-train combined cycle unit), and transmission and distribution infrastructure improvements. The proposed rate structure also included continuation of MECO s ECAC. The application requested a return on MECO s pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of deferred income taxes) in rate base. The application also proposed to restore book equity (in determining the equity balance for ratemaking purposes) for the amounts that were charged against equity (i.e., to AOCI) as a result of recording a pension and other postretirement benefits liability after implementing a new accounting standard at that time.

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

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

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

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

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

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

2010 test year rate case. On September 30, 2009, MECO filed a request with the PUC to increase base rates by $28.2 million, or 9.7% in annual base revenues, over the electric rates currently in effect (i.e., over rates that include the $13.2 million interim rate increase discussed above granted in MECO s 2007 test year rate case), based on a 2010 test year, an 8.57% ROR, a 10.75% ROACE and a $390 million average rate base. The proposed rate increase would cover investments to improve service reliability, including the replacement and upgrade of Maalaea generating units (M17 & M19) power plant control systems, installation of a new 100-kw photovoltaic system at MECO s Kahului Baseyard to incorporate solar energy into MECO s facilities, replacement and upgrade of underground lines, new or expanded substations to support past and future growth and improve service, and higher O&M expenses due to MECO s aging infrastructure. MECO s proposed ROR and ROACE assume the establishment of a revenue balance account and a revenue adjustment mechanism, based on the Joint Decoupling Proposal between the utilities (HECO, HELCO and MECO) and the Department of Commerce and Consumer Affairs. If the Joint Decoupling Proposal is not approved, the test year revenue requirements would have to be recalculated according to a ROR of 8.72% and a ROACE of 11%.

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

MECO proposes an inclining rate block structure for residential customers (similar to the structure MECO proposed in its 2007 test year rate case) and an optional residential and commercial time-of-use service rate to enable customers to manage their energy usage. The proposed rate structure also includes the continuation of MECO s ECAC. Pursuant to the Energy Agreement, MECO proposes the establishment of a purchased power adjustment clause to recover non-energy purchased power agreement costs to be effective upon issuance of the final D&O. The adoption of pension and OPEB tracking mechanisms is included in the test year estimates that were approved on an interim basis by the PUC in MECO s 2007 test year interim D&O.

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

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. On May 11, 2009, the utilities and the Consumer Advocate filed their joint final statement of position and the other parties filed their final statements of position. The utilities and Consumer Advocate s joint proposal is for a decoupling mechanism with two components: (1) a sales decoupling component via a revenue balancing account and a revenue escalation component via a revenue adjustment mechanism and (2) an earnings sharing mechanism. Panel hearings at the PUC were completed in July 2009 and post-hearing briefs were filed in September 2009. In their reply brief, the utilities requested the issuance of an interim D&O approving their proposed revenue balancing account and revenue adjustment mechanism.

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

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

Demand-side management programs. On February 13, 2007, the PUC issued its D&O in the Energy Efficiency Demand-Side Management (EE DSM) Docket that had been opened by the PUC to bifurcate the EE DSM issues originally raised in the HECO 2005 test year rate case. In the D&O, the PUC required that the administration of all EE DSM programs be turned over to a non-utility, third-party administrator, with the transition to the administrator, funded through a public benefits fund (PBF) surcharge. The PUC opened a new docket to select a third-party administrator and to refine details of the new market structure in an order issued in September 2007. In the order, the PUC stated that [u]pon selection of the PBF Administrator, the PUC intends, in this docket, to determine whether the electric utilities will be allowed to compete for the implementation of the Energy Efficiency DSM programs. In July 2008, the PUC issued an Order to Initiate the Collection of Funds for the PBF Administrator of Energy Efficiency Programs, which authorized the electric utilities to expense $50,000 per quarter beginning July 1, 2008 for the initial start-up costs associated with the PBF Administrator and recover the cost in the DSM surcharge; confirmed that the load management, SolarSaver Pilot (SSP) and Residential Customer Energy Awareness programs shall remain with the electric utilities; and directed the electric utilities to continue to operate the DSM programs through June 30, 2009, after which transition period the electric utilities can compete for implementation of DSM programs as a subcontractor.

The PUC executed a PBF Administrator contract with Science Applications International Corporation (SAIC) in March 2009.

On December 15, 2008, the PUC ordered that the $50,000 collected by the utilities during the third quarter of 2008 was to be paid to the PUC. In a separate order, Order Setting the Public Benefits Fee Surcharge for 2009 (Order), also dated December 15, 2008, the PUC established a Public Benefits Fund equal to 1% of estimated 2009 total revenues that would be used for the 2009 implementation of energy efficiency programs, of which 40% would be collected through the PBF Surcharge for use by the PBF Administrator, and 60% would be collected through the DSM Surcharge to be used by the utilities for their energy efficiency programs until those programs were transferred to the PBF Administrator. The Order stated that the 60/40 split roughly equates with the proportionate period of time that the commission expects the HECO Companies and the third-party administrator to provide services in 2009. The utilities issued new PBF Surcharge and revised DSM Surcharge filings effective January 1, 2009.

The utilities filed new DSM program budgets and goals on January 20, 2009.

The Order also ended the expensing and collection of $50,000 per quarter as of January 1, 2009. The $100,000 collected in total during the third and fourth quarters of 2008, plus interest, was delivered to the PUC s PBF fiscal agent, as instructed, on January 2, 2009. The utilities were ordered to transfer the collected PBF Surcharge revenues, less the revenue tax liabilities, to the PUC s PBF fiscal agent beginning on March 1, 2009, and monthly thereafter.

On July 1, 2009, SAIC began administering the energy efficiency DSM programs.

The EE DSM Docket D&O also provides for HECO s recovery of DSM program costs and utility incentives. With respect to cost recovery, the PUC continues to permit recovery of reasonably-incurred DSM implementation costs, under the IRP framework. On June 29, 2009, HECO filed with the PUC a request to increase its residential DSM programs budget by a net $1.4 million primarily to pay customer incentives related to DSM program applications that will have been completed and approved through June 30, 2009. The payments to customers of these incentives had been postponed in order for HECO to remain within the monthly program budgets. In June 2009, HECO accrued and expensed the net $1.4 million of incentives. The PUC required that HECO confirm that all required payments of customer incentives (related to undisputed program applications completed and approved through June 30, 2009 for the Residential Efficient Water Heating and Residential New Construction Programs) have been made, and HECO made the required incentive payments and provided the required confirmation in July 2009. HECO is awaiting a determination from the PUC on its request to increase its program budget, however, on August 13, 2009 the PUC issued an Order suspending the 45-day approval process for this request.

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DSM utility incentives will be derived from a graduated performance-based schedule of net system benefits. In order to qualify for an incentive, the utility must meet cumulative MW and MWh reduction goals for its EE DSM programs in both the commercial and industrial sector, and the residential sector. The amount of the annual incentive is capped at $4 million for HECO, and may not exceed either 5% of the net system benefits, or utility earnings opportunities foregone by implementing DSM programs in lieu of supply-side rate based investments. Negative incentives will not be imposed for underperformance.

In 2007, HECO recorded incentives of $4 million. HELCO and MECO proposed goals for their programs, based on the goals established for HECO s programs, but recorded no incentives in 2007. On May 21, 2007, the PUC clarified the 2007 and 2008 energy efficiency goals and the calculation of the DSM utility incentive, and granted HECO the ability to request program modifications and budget increases by letter request. Since that time, the PUC has approved budget increases and program modifications for various DSM programs. In June 2008, the PUC issued an order approving MECO s proposed cumulative energy and demand savings goals for 2007 and 2008, but set MECO s annual incentive cap at $320,000. Thus, in the second quarter of 2008, MECO recorded an incentive of $320,000 related to 2007. The PUC also issued an order approving HELCO s proposed cumulative energy and demand savings goals for 2007 and 2008, and an annual incentive cap of $200,000. However, HELCO did not achieve those goals and, therefore, no incentives were earned by HELCO. The utilities DSM incentives for 2007 and 2008 were subject to adjustment based on the results of impact evaluation studies.

In December 2008, the results of the impact evaluation studies became available. The impact evaluation reduced actual DSM energy and demand savings for 2005 through 2007. As a result of the reduced savings, the utilities Lost Margin and Shareholder Incentives earned in 2005 and 2006 were reduced. In addition, MECO no longer met its 2007 goals for DSM utility incentives. As a result of these changes, the utilities accrued a refund to its customers of $1.4 million, including interest, in December 2008. The refund was included in the DSM surcharge adjustments effective on April 1, 2009 for HECO, and on May 1, 2009, for HELCO and MECO. On September 17, 2009, the PUC requested a final summary explaining all adjustments and revisions made as a result of the impact evaluation. On October 19, 2009 the utilities filed this summary.

HECO and MECO surpassed their energy and demand savings goals for 2008 and earned their maximum DSM utility incentives of $4 million and $320,000, respectively. In its December 15, 2008 Order, in anticipation of the transfer of the DSM programs to the third-party administrator during 2009, the PUC decreased the maximum DSM utility incentive for HECO to $2 million for 2009 and decreased HELCO s and MECO s maximum incentives to $100,000 and $160,000, respectively, for 2009.

HECO filed its annual DSM Accomplishments and Surcharge Report (A&S Report) on March 31, 2009, which documents HECO s portion of the refund for years 2005 and 2006 and its earned DSM utility incentive of $4 million. MECO filed its A&S Report on April 30, 2009, documenting its portion of the refund and its earned DSM utility incentive of $320,000.

Unlike the EE DSM programs, load management DSM programs will continue to be administered by the utilities. HECO s residential load management program includes a monthly electric bill credit for eligible customers who participate in the program, which allows HECO to disconnect the customer s residential electric water heaters or central air conditioning systems from HECO s system to reduce system load when deemed necessary by HECO. The commercial and industrial load management program provides an incentive on the portion of the demand load that eligible customers allow to be controlled or interrupted by HECO. This program includes small business direct load control and voluntary program elements.

In March and April 2009, HECO filed applications for three-year extensions, from 2010 through 2012, of the Commercial and Industrial Direct Load Control (CIDLC) Program and the Residential Direct Load Control (RDLC) Program, respectively. Without an extension of the programs by the PUC, the CIDLC and RDLC Programs will terminate on December 31, 2009. The CIDLC Program application included an action plan for a load aggregator pilot program. An RFP for the load aggregator was issued and bid proposals were received in September 2009. HECO is currently evaluating the bid proposals. In October 2009, HECO briefed the PUC on the status, benefits, and plans for the two direct load control programs and demand response in general.

In April 2008, HECO filed an application for approval of a Dynamic Pricing Pilot (DPP) Program and for recovery of the incremental costs of the program through the DSM Adjustment component of the IRP Cost Recovery

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Provision. Dynamic pricing is a type of demand response program that allows prices to change from normal tariff rates as system conditions change and encourages customer curtailment of load through price incentives when there is insufficient generation to meet a projected peak demand period. The proposed pilot program would run for approximately one year and test the effect of a demand response program on a sample of residential customers. In its February 18, 2009 Statement of Position (SOP), the Consumer Advocate did not object to the PUC s approval of the proposed pilot program, with certain qualifications. In June 2009, the PUC, in its Order Directing HECO to Modify its Dynamic Pricing Pilot Program, directed HECO to modify the DPP Program to address the recommendations and concerns outlined in the Consumer Advocate s SOP , or alternatively, HECO and the Consumer Advocate may file a stipulated proposed DPP Program. HECO met with the Consumer Advocate in September 2009 to discuss its recommendations and concerns and presented a revised DPP Program design for the Consumer Advocate s consideration. HECO s response to the PUC s order and its filing date are dependent on the outcome of discussions with the Consumer Advocate.

Avoided cost generic docket. In May 1992, the PUC instituted a generic investigation to examine the proxy method and formula used by the electric utilities to calculate their avoided energy costs and Schedule Q rates. In general, Schedule Q rates are available to customers with cogeneration and/or small power production facilities with a capacity of 100 kW or less who buy power from or sell power to the electric utility. The parties to the proceeding agreed that avoided fuel costs, except for Lanai and Molokai, would be determined using a computer production simulation model and agreed on certain parameters that would be used to calculate avoided costs. In March 2008, the PUC ordered that the new avoided energy cost rates and Schedule Q rates would go into effect on August 1, 2008. HECO, HELCO and MECO filed new avoided energy costs rates and Schedule Q rates, which were determined using the new differential revenue requirements resource-in / resource-out methodology instead of the proxy method. These rates were effective from August 1 through December 31, 2008, and the fuel component of the rates was adjusted monthly for changes in fuel prices.

On April 18, 2008, the PUC initiated a docket to examine the methodology for calculating Schedule Q electricity payment rates in the State of Hawaii. The proceeding was intended to examine new methodologies for calculating Schedule Q payment rates, with the intent of removing or reducing any linkages between the price of fossil fuels and the rate for non-fossil fuel generated electricity. The parties to the Energy Agreement agreed that all new renewable energy contracts are to be delinked from fossil fuel and that the utilities would seek to renegotiate existing PPAs with independent power producers (IPPs) that are based on fossil fuel prices to delink their energy payment rates from oil costs. Based on this understanding, the parties agreed to request that the PUC suspend the pending Schedule Q proceeding for a period of 12 months with a view to reviewing the necessity of the docket. On November 28, 2008, the PUC granted the request to suspend the Schedule Q proceeding for 12 months. On December 31, 2008, HECO, HELCO and MECO filed avoided energy costs rates and Schedule Q rates to be effective for 2009, subject to monthly adjustment of the fuel component of the rates for changes in fuel prices.

Integrated resource planning, requirements for additional generating capacity and adequacy of supply. The PUC issued an order in 1992 requiring the energy utilities in Hawaii to develop integrated resource plans (IRPs), which may be approved, rejected or modified by the PUC. The goal of integrated resource planning is the identification of demand- and supply-side resources and the integration of these resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. The utilities proposed IRPs are planning strategies, rather than fixed courses of action, and the resources ultimately added to their systems may differ from those included in their 20-year plans. Under the PUC s IRP framework, the utilities are required to submit annual evaluations of their plans (including a revised five-year program implementation schedule) and to submit new plans on a three-year cycle, subject to changes approved by the PUC. Prior to proceeding with the DSM programs, separate PUC approval proceedings must be completed.

The utilities were to be entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, including the costs of DSM programs, either through a surcharge or through their base rates. Under procedural schedules for the IRP cost proceedings, the utilities were able to recover their incremental IRP costs in the month following the filing of their actual costs incurred for the year, subject to refund with interest pending the PUC s final D&O approving recovery in the docket for each year s costs. HELCO (since February 2001), HECO (since September 2005) and MECO (since December 2007) now recover IRP costs (which are included in O&M) through base rates. Previously, HECO, HELCO and MECO recovered their costs through a surcharge. The Consumer Advocate has objected to the recovery of $1.2 million (before interest) of the $4.0 million of incremental IRP costs incurred by the utilities during the 2002-2007 period, and the PUC s decisions on the recovery of these costs are pending. Also, see Note 5 in HECO s Notes to Consolidated Financial Statements and Demand-side management programs above.

The parties to the Energy Agreement agreed to seek to replace the IRP process with a new Clean Energy Scenario Planning (CESP) process, described in the Energy Agreement, intended to be used to determine future investments in transmission, distribution and generation that will be necessary to facilitate high levels of renewable energy production. Requests by the parties to the Energy Agreement to move to the CESP process were filed with the PUC on November 6, 2008, and the PUC acted on those requests by ordering the utilities and the Consumer Advocate to develop a joint proposal for a framework for the CESP process. HECO and the Consumer Advocate filed a proposed CESP framework with the PUC on April 28, 2009. The proposed CESP framework revises the previous IRP framework and proposes a planning process to develop generation and transmission resource plan options for multiple 20-year planning scenarios. From these scenarios, the framework proposes the development of a 5-year Action Plan based on range of resource needs identified through the various scenarios analyzed. Furthermore, the framework proposes that the CESP include the identification of Renewable Energy Zones, or geographic areas of the islands of rich renewable energy resources in which infrastructure improvements should be focused. The framework also proposes that the CESP include the identification of any geographic areas of the distribution system in which distributed generation or DSM resources are of higher value. The parties committed to supporting reasonable and prudent investment in the ongoing maintenance and upgrade of the existing generation, transmission and distribution systems, unless the CESP process determines otherwise. On May 14, 2009, the PUC opened an investigative proceeding to examine the proposed CESP framework. In addition to HECO, HELCO, Kauai Island Utility Cooperative (KIUC) and the Consumer Advocate, eleven parties have been allowed as intervenors in the proceeding. The PUC issued a Prehearing Order in September 2009 with panel hearings scheduled in January 2010.

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

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

On November 26, 2008, the PUC closed the HECO IRP-4 process and directed HECO to suspend all activities pursuant to the IRP framework to allow for resources to be diverted to the development of a CESP framework.

HELCO s IRP. In May 2007, HELCO filed its third IRP. The plan included the installation of a nominal 16 MW steam turbine (ST-7) in 2009 at its Keahole Generating Station (see Major projects in Note 5 of HECO s Notes to Consolidated Financial Statements). The plan also followed through on a commitment to have no new fossil-fired generation installed after ST-7. The plan anticipated increasing customer photovoltaic systems plus a 37 gigawatthours per year renewable energy resource in the 2014 to 2020 timeframe, a firm capacity renewable energy resource in 2022, energy efficiency (continuation of existing DSM programs) and CHP. In November 2007, HELCO and the Consumer Advocate filed a stipulated agreement which recommended that the PUC approve HELCO s IRP-3 and in which HELCO agreed to make improvements to the IRP process and to submit evaluation reports. In January 2008, the PUC issued its D&O approving HELCO s IRP-3 and required HELCO to submit annual evaluation reports and file its IRP-4 by May 31, 2010.

On November 26, 2008, the PUC suspended the HELCO IRP-4 process and directed HELCO to suspend all activities pursuant to the IRP Framework to allow for resources to be diverted to the development of a CESP framework.

MECO s IRP. In April 2007, MECO filed its third IRP, which proposes multiple solutions to meet future energy needs on the islands of Maui, Lanai and Molokai, including renewable energy resources (such as photovoltaics, additional wind, biomass and waste-to-energy), energy efficiency (continuation of existing and addition of new DSM programs), technology (such as CHP and DG) and competitive bidding for generation or blocks of generation on Maui for 20 MW in each of 2011 and 2013 and 18 MW in 2024 which, under the utility parallel plan, could be located at its Waena site. In July 2008, the PUC approved MECO s IRP-3 and directed MECO to submit evaluation reports, to make various improvements to the IRP process and to submit its IRP-4 by April 30, 2010.

On December 8, 2008, the PUC suspended the MECO IRP-4 process and directed MECO to suspend all activities pursuant to the IRP Framework to allow for resources to be diverted to the development of a CESP framework.

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

Adequacy of supply.

HECO. HECO s 2009 Adequacy of Supply (AOS) letter, filed in February 2009, indicated that HECO s analysis estimates its reserve capacity shortfall to be approximately 30 MW in 2009, even with the addition of the CIP CT-1, primarily because shortfalls are projected to occur before the unit is installed and will not be entirely alleviated once the unit is available for service. Generation shortfalls did not occur during the first half of 2009, in part because power demand was consistently less than forecasted primarily due to weather that was cooler than normal. Moreover, sustained maintenance efforts have resulted in a leveling in availability rates that had been declining since 2002, at levels that continue to be better than those for comparable units on the U.S. mainland. Generation capacity shortfalls did not occur prior to or after the startup of CIP CT-1 when reserve capacity conditions were substantially improved.

To mitigate the projected reserve capacity shortfalls, HECO has implemented and is continuing to plan and implement mitigation measures, such as installing distributed generators at substations or other sites, implementing additional load management and other demand reduction measures, and pursuing efforts to improve the availability of generating units.

HECO reported in its 2009 AOS letter that, after the scheduled mid-2009 addition of the CIP CT-1, and in recognition of the uncertainty underlying key forecasts, it anticipates that its reserve capacity situation could range from a shortfall of 10 MW if demand is higher than expected to a surplus of 50 MW in a base case scenario for 2010, with the shortfalls higher and the surpluses lower in future years. In May 2009, HECO prepared a new sales and peak forecast in which HECO projected peak demand to be lower than previously forecast in September 2008. However, actual recorded peaks since May 2009 have been more closely tracking the September 2008 forecast. Therefore, the analyses and conclusions in the 2009 AOS letter (that used the September 2008 forecast) continue to be valid. As noted under HECO s IRP above, HECO is revisiting its plans to submit an application and waiver request to pursue the installation of a second biofueled CT (100 MW) at its CIP generating station in the 2011-2012 timeframe given the uncertainty of future sales and peak demand. HECO may seek, under the guidance of the Competitive Bidding Framework issued by the PUC in December 2006, a firm, dispatchable renewable resource to meet future needs, while continuing contingency planning activities.

HECO s gross peak demand was 1,327 MW in 2004, 1,273 MW in 2005, 1,315 MW in 2006, 1,261 MW in 2007 and 1,227 MW in 2008. Peak demand may vary from year to year, but over time, demand for electricity on Oahu is projected to increase. On occasions in 2004 through 2007, HECO issued public requests that its customers voluntarily conserve electricity as generating units were out for scheduled maintenance or were unexpectedly unavailable. In addition to making the requests, in 2005 through 2007 and in 2009, HECO on occasion remotely turned off water heaters for a number of residential customers who participate in its load-control program. No such requests were made or actions taken in 2008. 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.

HELCO. HELCO s 2009 Adequacy of Supply letter filed in January 2009 indicated that HELCO s generation capacity for the next three years, 2009 through 2011, is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

MECO. MECO s 2009 Adequacy of Supply letter filed in January 2009 indicated that MECO s generation capacity for the next three years, 2009 through 2011, is sufficient to meet the forecasted demands on the islands of Maui, Lanai and Molokai. MECO s 2009 Adequacy of Supply letter also indicated that the date the next increment of additional firm generating capacity on Maui is needed has changed from 2014 to 2015 due primarily to a reduction in the forecast of peak demand. On September 28, 2009, MECO filed an update to its AOS letter and informed the PUC that the need date for the next increment of firm generation capacity on the island of Maui was changed from 2015 to 2021 due to a reduction in the forecast of peak demand. MECO also noted that if peak demand is higher than forecast, the need date for the next increment of firm generation capacity could be as soon as 2015. Based on the 2021 need date for additional firm capacity, on October 15, 2009, MECO requested that the PUC close the related docket and terminate the competitive bidding process.

The PPA between MECO and Hawaiian Commercial & Sugar Company (HC&S), which provides for 16 MW of firm capacity, continues in effect from year to year, subject to termination on written notice by either party of not less than two years. In July 2007, however, the parties agreed to not issue a notice of termination that would result in the termination of the PPA prior to the end of 2014.

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

On January 12, 2009, the PUC issued an order initiating an investigation of the outage to address the following preliminary issues: (1) what caused the outage; (2) if lightning strikes during the lightning storm initially caused the power outage, could HECO have reasonably prevented damaging effects of lightning strikes to prevent the power outage from initially occurring; (3) through reasonable measures, could HECO have prevented the power outage or prevented it from becoming island-wide; (4) could HECO have reasonably shortened the duration of the power outage and restored power more quickly to customers; (5) what are the necessary steps to prevent similar power outages in the future, to minimize the scope and duration of similar power outages and to improve HECO s response to such outages in the future; and (6) what penalties, if any, should be imposed on HECO.

On March 31, 2009, HECO submitted its outage report that was prepared by its expert consultant, POWER Engineers, Inc. (POWER). The outage report concluded that the island-wide outage was triggered by lightning strikes on or near HECO s 138 kilovolt (kV) transmission system, one of which resulted in a short-circuit over all three phases of the Kahe-Waiau 138 kV line, setting in motion a series of events that resulted in the necessary loss of customer load, loss of generation and the eventual island-wide shut down of HECO s system. POWER found that: (1) the HECO system was in proper operating condition and was appropriately staffed at the time of the lightning storm, and (2) HECO s restoration efforts were prudent and allowed for the restoration of power as quickly as possible under the circumstances, while also ensuring the safety and protection of HECO s employees and customers and preventing any further or permanent damage to the electric system from attempts to bring the system back too quickly. POWER made a number of recommendations, largely technical in nature, for HECO to consider that may reduce the likelihood of the recurrence of a similar power outage or minimize the duration of an outage should one occur in the future.

The Consumer Advocate and the PUC will review the outage report and conduct their own independent reviews. The Consumer Advocate s consultants have been conducting a detailed review of the outage, which review is ongoing.

Management cannot at this time predict the outcome of the PUC s or Consumer Advocate s investigations or their impact on HECO.

Intra-governmental wheeling of electricity. In June 2007, the PUC initiated a docket to examine the feasibility of implementing intra-governmental wheeling of electricity in the State of Hawaii. In the fourth quarter of 2008, the Department of Business, Economic Development and Tourism requested (in accordance with the provisions of the Energy Agreement) that the PUC suspend the pending intra-governmental wheeling docket for a period of 12 months while the parties to the agreement evaluate the necessity of the docket in view of the other agreements of the parties. The PUC approved the request, provided that the PUC, at its option, may re-institute this docket at an earlier date. On October 27, 2009, the PUC issued a letter asking for any written comments from the parties and participants in the docket on how to proceed, including whether an extension of the suspension period is appropriate.

Energy Independence and Security Act of 2007. On February 11, 2009, the PUC issued an order initiating an investigation whether to implement any of four new federal standards, as required by the Public Utility Regulatory Policies Act of 1978, as amended by the Energy Independence and Security Act of 2007. In summary, the four standards are as follows: (1) each electric utility shall integrate energy efficiency resources into utility, state and regional plans and adopt policies establishing cost-effective energy efficiency as a priority resource; (2) electric utility rates shall align utility incentives with the delivery of cost-effective energy efficiency and promote energy efficiency investments; (3) each state shall consider requiring that, prior to undertaking investments in non-advanced grid technologies, an electric utility demonstrate to the state that it considered an investment in a qualified smart grid system; and (4) all electricity purchasers shall be provided direct access to pricing, usage and power source information from their electricity provider. The PUC named HECO, HELCO, MECO, Kauai Island Utility Cooperative and the Consumer Advocate as parties in this proceeding. In May 2009, HECO, HELCO and MECO filed a joint position statement recommending that the PUC decline to adopt the four new federal standards, as there are already existing processes and proceedings before the PUC to consider Hawaii-specific standards. On September 30, 2009, the PUC issued its D&O declining to adopt the new federal standards.

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

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

Renewable Portfolio Standard. Act 155, passed by the 2009 Hawaii legislature and signed into law by the Governor, has amended Hawaii s RPS law to require electric utilities to meet an RPS of 10% by December 31, 2010, 15% by December 31, 2015, 25% by December 31, 2020, and 40% by December 31, 2030. The revised RPS law is consistent with the commitment the utilities agreed to in the Energy Agreement signed as part of the HCEI and provides that beginning January 1, 2015, electrical energy savings from renewable energy displacement technologies (such as solar water heating) or from energy efficiency and conservation programs shall not count toward the RPS. The amended RPS law includes a requirement for the PUC to evaluate the standard every five years, beginning in 2013, to determine whether the standards remain effective and achievable and whether the standards should be revised in light of their findings. The standard under the law prior to the amendment (8% of KWH sales by December 31, 2005) was met in 2005 when the electric utilities attained an RPS of 11.7%. The utilities are committed to achieving these RPS goals; however, due to risks such as potential delays in IPPs being able to deliver contracted renewable energy (see risks under Forward-looking Statements), it is possible the electric utilities may not attain the required renewable percentages in the future, and management cannot predict the future consequences of failure to do so (including potential penalties to be assessed by the PUC).

The RPS law was amended in 2006 to add provisions for penalties if the utility fails to meet its RPS requirements, to require the PUC to conduct a hearing prior to assessing penalties, and to amend the criteria for waiver of the penalties by the PUC. In January 2007, the PUC opened a new docket (RPS Docket) to examine Hawaii s RPS law, to establish the appropriate penalties for failure to meet RPS targets and to determine the circumstances under which penalties should be levied. The issues also included the appropriate utility ratemaking structure to include in the RPS framework to provide incentives that encourage electric utilities to use cost-effective renewable energy resources found in Hawaii to meet the RPS, while allowing for deviation from the standards in the event that the standards cannot be met in a cost-effective manner, or as a result of circumstances beyond the control of the utility that could not have been reasonably anticipated or ameliorated.

On June 30, 2009, HECO filed an RPS report in which it indicated that the utilities had attained an RPS of 18% for 2008. However, the report noted that DSM programs contributed significantly to achieving this RPS level, and indicated that, without including the energy savings, the RPS would have been 9.3% instead of 18%. Under current RPS law, energy savings resulting from energy efficiency programs will not count toward the RPS from January 1, 2015.

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. See Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements for a further discussion of the penalty.

In its December 2007 D&O, the PUC deferred the RPS incentive framework to a new generic docket (Renewable Energy Infrastructure Program or REIP Docket). The parties to the REIP Docket include the electric utilities, the Consumer Advocate, an environmental organization and Hawaii Renewable Energy Alliance (HREA). Public hearings were held in May 2008.

The Renewable Energy Infrastructure Program proposed by HECO in the RPS docket consists of two components: (1) renewable energy infrastructure projects that facilitate third-party development of renewable energy resources, maintain existing renewable energy resources and/or enhance energy choices for customers, and (2) the creation and implementation of a temporary renewable energy infrastructure surcharge to recover the capital costs, deferred costs for software development and licenses, and/or other relevant costs approved by the PUC. These costs would be removed from the surcharge and included in base rates in the utility s next rate case. In July 2008, statements of position were filed with the PUC, in which the Consumer Advocate recommended approval of, HREA supported, and the environmental organization did not oppose the REIP proposed by HECO. In October 2008, pursuant to the PUC s request, the parties to the docket informed the PUC, among other things, that the parties (1) have reached an agreement on all of the issues in the docket, (2) agree that it is appropriate that the PUC approve the utilities proposed REIP and related REIP surcharge, (3) agree that the record in the proceeding is complete and ready for PUC decision-making, and (4) waive an evidentiary hearing. In the first quarter of 2009, the parties responded to information requests prepared by the PUC s consultant, and in July 2009, the utilities and the Consumer Advocate submitted separate legal briefs, which responded to the PUC s questions on legal issues.

In the Energy Agreement, the parties also agreed that the REIP may be modified to incorporate changes for the CEIS mechanism, provided the appropriate notices to the public regarding the changes are made.

On November 28, 2008, HECO and the Consumer Advocate filed a joint letter informing the PUC that the proposed REIP Surcharge is substantially similar to the CEIS and that the REIP Surcharge proposal satisfies the Energy Agreement commitment for the filing of an implementation procedure for the CEIS.

Management cannot predict the outcome of these proceedings and processes.

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Net energy metering (NEM). Hawaii has a NEM law, which requires that electric utilities offer NEM to eligible customer generators (i.e., a customer generator may be a net user or supplier of energy and will make payment to or receive credit from the electric utility accordingly).

In 2005, the Legislature amended the NEM law by, among other revisions, authorizing the PUC, by rule or order, to increase the maximum size of the eligible net metered systems and to increase the total rated generating capacity available for NEM. In April 2006, the PUC initiated an investigative proceeding on whether the PUC should increase (1) the maximum capacity of eligible customer-generators to more than 50 kW and (2) the total rated generating capacity produced by eligible customer-generators to an amount above 0.5% of an electric utility s system peak demand. The parties to the proceeding include HECO, HELCO, MECO, Kauai Island Utility Cooperative (KIUC), the Consumer Advocate, a renewable energy organization and a solar vendor organization. In March 2008, the PUC approved a stipulated agreement filed by the parties (except for KIUC, which has its own stipulated agreement) to increase the maximum size of the eligible customer-generators from 50 kW to 100 kW and the system cap from 0.5% to 1.0% of system peak demand, to reserve a certain percentage of the 1.0% system peak demand for generators 10 kW or less and to consider in the IRP process any further increases in the maximum capacity of customer-generators and the system cap. The PUC further required the utilities: (1) to consider specific items relating to NEM in their respective IRP processes, (2) to evaluate the economic effects of NEM in future rate case proceedings and (3) to design and propose a NEM pilot program for the PUC s review and approval that will allow, on a trial basis, the use of a limited number of larger generating units (i.e., at least 100 kW to 500 kW, and may allow for larger units) for NEM purposes.

In April 2008, the electric utilities applied for PUC approval of a proposed four-year NEM pilot program to evaluate the effects on the grid of units larger than the currently approved maximum size. The program will consist of analytical investigations and field testing and is designed for a limited number of participants that own (or lease from a third party) and operate a solar, wind, biomass, or hydroelectric generator, or a hybrid system. The electric utilities propose to recover program costs through the IRP cost recovery provision.

In 2008, the NEM law was again amended to authorize the PUC, by rule or order, to modify the maximum size of the eligible net metered systems and evaluate on an island-by-island basis whether to exempt an island or utility grid system from the total rated generating capacity limits available for NEM.

In the Energy Agreement, the parties agreed to seek to remove system-wide caps on NEM. Instead, they plan to seek to limit DG interconnections on a per circuit basis and to replace NEM with an appropriate feed-in tariff and new net metered installations that incorporate time-of-use metering equipment for future full scale implementation of time-of-use metering and sale of excess energy.

On February 13, 2009, the parties to the NEM proceeding filed a joint letter pointing out that the Energy Agreement calls for the development of a feed-in tariff that may eventually replace NEM and that the outcome of the feed-in tariff proceeding may influence the future direction of NEM. The parties proposed to provide an update on the proposed pilot program within a month after the completion of the feed-in tariff proceeding.

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.

DSM programs. See Demand-side management programs above.

Non-fossil fuel purchased power contracts. In 2006, a law was enacted that required that the PUC establish a methodology that removes or significantly reduces any linkage between the price paid for non-fossil-fuel-generated electricity under future power purchase contracts and the price of fossil fuel, in order to allow utility customers to receive the potential cost savings from non-fossil fuel generation (in connection with the PUC s determination of just and reasonable rates in purchased power contracts).

Renewable energy. In 2007, a law was enacted that stated that the PUC may consider the need for increased renewable energy in rendering decisions on utility matters. Due to this measure, it is possible that, if energy from a renewable source were more expensive than energy from fossil fuel, the PUC may still approve the purchase of energy from the renewable source.

In 2008, a law was enacted to promote and encourage the use of solar thermal energy. This measure will require the installation of solar thermal water heaters in residences constructed after January 1, 2010, but allow for limited variances in cases where installation of solar water heating is deemed inappropriate. The measure will establish standards for quality and performance of such systems. Also in 2008, a law was enacted that is intended to facilitate the permitting of larger (200 MW or greater) renewable energy projects. The Energy Agreement includes several undertakings by the utilities to integrate solar energy into the electric grid.

In 2009, a bill became law (Act 185) that authorizes preferential rates to agricultural energy producers selling electricity to utilities. In addition, pursuant to Act 50, avoided cost is no longer a consideration in determining a just and reasonable rate for non-fossil fuel generated electricity.

Biofuels. In 2007, a law was enacted with the stated purpose of encouraging further production and use of biofuels in Hawaii. It established that biofuel processing facilities in Hawaii are a permitted use in designated agricultural districts and established a program with the Hawaii Department of Agriculture to encourage the production in Hawaii of energy feedstock (i.e., raw materials for biofuels).

In 2008, a law was enacted that encourages the development of biofuels by authorizing the Hawaii Board of Land and Natural Resources to lease public lands to growers or producers of plant and animal material used for the production of biofuels.

The utilities have agreed in the Energy Agreement to test the use of biofuels in their generating units and, if economically feasible, to connect them to the use of biofuels. For its part, the State agrees to support this testing and conversion by expediting all necessary approvals and permitting. The Energy Agreement recognizes that, if such conversion is possible, HECO s requirements for biofuels would encourage the development of a local biofuels industry. HECO and MECO have applied to the PUC for authority to enter into and recover the costs of biodiesel fuel contracts under which they will purchase biofuels to test their use in HECO and MECO generating units.

Suspension of Hawaii capital goods excise tax credit. Act 178, which became law on July 15, 2009, temporarily suspended the Hawaii capital goods excise tax credit for property placed in service between May 1 and December 31, 2009. This credit is a 4% investment credit on depreciable tangible personal property placed into service in Hawaii. This suspension of the credit could increase HECO s consolidated current income tax liability by as much as $6 million, depending on the property placed in service during the suspension period. Since these tax credits are deferred and amortized over the expected lives of the properties, the annual net income impact of losing these credits would be significantly lower and is estimated to be $0.2 million per year for the next 30 years.

For additional discussion of environmental legislation and regulations, see Environmental regulation in Note 5 of HECO s Notes to Consolidated Financial Statements.

At this time, it is not possible to predict with certainty the impact of the foregoing legislation or legislation that is, or may in the future be, proposed.

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Other developments

Advanced Metering Infrastructure (AMI). On December 1, 2008, the utilities filed an AMI project application with the PUC for approval to implement AMI, covering approximately 451,000 meters (293,000 on Oahu, 92,000 on the island of Hawaii and 66,000 on Maui). The application embodies the goals of the HCEI, which is further described in Note 5 of HECO s Notes to Consolidated Financial Statements. Hearings were initially scheduled for July 2009, but have been rescheduled for July 2010. The delay will allow the utilities to provide information on their Smart Grid roadmaps, and how the proposed AMI project will facilitate the roadmaps. The additional time will also allow the utilities to assess the impact, if any, of ongoing developments with respect to their new Customer Information System (CIS) and Cyber-Security. HECO issued a Request for Proposal (RFP) to a selected set of consultants with experience in developing Smart Grid roadmaps and anticipates awarding a contract in the fourth quarter of 2009.

The AMI project application includes a request to approve a contract between Sensus Meter Systems, Inc. and HECO under which the utilities would purchase smart meters and pay Sensus to provide and maintain an AMI system to operate the smart meters. By its terms, either party may declare the contract null and void if it is not approved by the PUC by November 30, 2009.

HECO continues to operate a Sensus AMI network, currently consisting of 8,700 advanced meters at both residential and commercial customer sites on Oahu, and will be starting the RFP development process for the selection of commercially-available Meter Data Management (MDM) software. This effort is being closely coordinated with the utilities plan to procure a new CIS. The MDM will ultimately capture the increased data volume from advanced meters and will serve as the data warehouse and knowledge store for current and future utility applications, and integrate with the utilities CIS.

AMI technology enables automated meter reading, improved field service operations, improved meter accuracy, time-of-use pricing and conservation options for utility customers. The utilities plan to utilize the Smart Grid roadmaps to help explore other utility applications such as distribution circuit monitoring and water heater and air conditioning load control for improved residential and commercial customer reliability and renewables support. AMI technology is rapidly evolving and has become an integral part of the utilities Smart Grid planning.

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

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

FINANCIAL CONDITION

Liquidity and capital resources

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

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

(in millions)	September 30, 2009		December 31, 2008	
Short-term borrowings	$ 11	%	$ 42	2%
Long-term debt	1,058	46	905	42
Cumulative preferred stock	22	1	22	1
Noncontrolling interest cumulative preferred stock of subsidiaries	12	1	12	
Common stock equity	1,212	52	1,189	55
	$ 2,315	100%	$ 2,170	100%

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As of October 27, 2009, the S&P and Moody s ratings of HECO securities were as follows:

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

The above ratings reflect only the view of the applicable rating agency at the time the ratings are issued, from whom an explanation of the significance of such ratings may be obtained. Such ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating. HECO s overall S&P corporate credit rating is BBB/Negative/A-3. HECO s issuer rating by Moody s is Baa1 and Moody s outlook for HECO is negative.

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

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

The rating agencies use a combination of qualitative measures (e.g., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HECO securities. In May 2009, S&P revised HECO s outlook to negative from stable, and lowered HECO s short-term rating to A-3 from A-2. S&P indicated the rating actions reflected its view that the next two years are likely to be challenging for HEI s electric utilities. S&P stated that the deterioration in the Hawaii economy is likely to weaken 2009 and 2010 consolidated metrics, which it observed have been only marginally supportive of the BBB corporate credit ratings currently assigned to HECO. In July 2009, S&P issued a bulletin which stated the interim ruling July 2 in Hawaiian Electric Co. Inc. s (HECO; BBB/Negative/A-3) rate case and a recently announced delay in the company s rate case hearings is adverse for credit quality but is adequately captured in the negative outlook assigned to the ratings last month.

S&P designates business risk profiles as excellent, strong, satisfactory, fair, weak or vulnerable. S&P s financial risk designations are m modest, intermediate, significant, aggressive and highly leveraged. In October 2009, S&P listed HECO s business risk profile as strong a financial risk profile as significant.

On July 20, 2009, Moody s issued a news release in which it indicated it had changed HECO s rating outlook to negative from stable, affirmed HECO s long-term and short-term (commercial paper) ratings, and assigned a Baa1 rating to the $150 million senior unsecured SPRBs due 2039 that were subsequently issued on July 30, 2009 by the Department of Budget and Finance of the State of Hawaii (DBF) for the benefit of HECO and HELCO. See discussion below regarding the negative outlook and rating affirmation.

Subsequently on August 3, 2009, Moody s issued a credit opinion on HECO. Moody s indicated that the rating affirmation reflects the fact that notwithstanding the issues outlined in the credit opinion, the utilities financial metrics are reasonably positioned in its rating category. Regarding the negative rating outlook, Moody s indicated that HECO s negative rating outlook reflects the impact of a weakened economy that is affecting electric demand and electric sales resulting in weaker financial performance, which may be influencing the outcome of state regulatory decisions, at a time when the company s capital investment program is substantial. Moody s stated that [t]he rating

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could be downgraded should weaker than expected regulatory support emerge at HECO or if the economy worsens materially more than anticipated causing earnings and sustainable cash flows to suffer. Consequently, if the utilities financial ratios declined on a permanent basis such that FFO (Funds From Operations defined as net cash flow from operations less net changes in working capital items) to Adjusted Debt falls below 17% (17% last twelve months as of March 31, 2009-latest reported by Moody s) or FFO to Adjusted Interest declines to less than 3.5x (3.6x last twelve months as of March 31, 2009-latest reported by Moody s) for an extended period, the rating could be lowered.

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

	Nine months ended September 30, 2009		
(in millions)	**Average balance**	**End-of-period balance**	**December 31, 2008**
Short-term borrowings			
Commercial paper	$ 0.4	$	$
Line of credit draws	15		
Borrowings from affiliates	26	11	42
Line of credit facilities [1]			
Undrawn capacity under line of credit facility expiring March 31, 2011 [2]		175	175
Undrawn capacity under line of credit facility expiring September 8, 2009 [3]			75
Special purpose revenue bonds authorized for issue			
2005 legislative authorization (expiring June 30, 2010)-HELCO		$ 20	$ 20
2007 legislative authorization (expiring June 30, 2012)			
HECO		170	260
HELCO		55	115
MECO		25	25
Total special purpose revenue bonds available for issue		$ 270	$ 420

1 At October 27, 2009, there was no outstanding commercial paper balance and the credit facility expiring on March 31, 2011 was undrawn. HECO may seek to modify the credit facility expiring March 31, 2011 in accordance with the expedited approval process approved by the PUC, including to increase the amount of credit available under an agreement, and/or to enter into new lines of credit, as management deems appropriate.

2 In April 2009, HECO filed with the PUC a request for expedited approval of Amendment No. 2 (which the Required Lenders, as defined in the agreement, signed) to the $175 million credit facility. Among other things, Amendment No. 2 eliminates from the credit agreement representations relating to the funded status of HECO s pension plan, which were not correct. On May 26, 2009, the PUC approved the Amendment No. 2.

3 On August 4, 2009, the $75 million credit facility terminated in accordance with its terms based on the completion on July 30, 2009 of the $150 million SPRB offering for the benefit of HECO and HELCO.

HECO utilizes short-term debt, typically commercial paper, to support normal operations and for other temporary requirements. In June 2009, HECO began drawing on the credit facility expiring March 31, 2011, rather than issuing commercial paper. HECO also borrows short-term from HEI for itself and on behalf of HELCO and MECO, and HECO may borrow from or loan to HELCO and MECO short-term. The intercompany borrowings among the utilities, but not the borrowings from HEI, are eliminated in the consolidation of HECO s financial statements. At September 30, 2009, HECO had $11 million and $10 million of short-term borrowings from HEI and MECO, respectively, and HELCO had $25 million of short-term borrowings from HECO. HECO had average outstanding balances of commercial paper and credit facility draws for the first nine months of 2009 of $0.4 million and $15 million, respectively, and had no commercial paper or credit facility draws outstanding at September 30, 2009. Due to market conditions since September 2008 which resulted in a tightening of the commercial paper (CP) market, higher CP rates and limitations on maturity options as well as a result of S&P s downgrade of HECO s short-term borrowing rating to A-3 from A-2, HECO began drawing on its $175 million syndicated line of credit facility in June 2009, rather than issuing commercial paper. Management believes that, if HECO s commercial paper ratings were to

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be further downgraded or if credit markets were to further tighten, it would be even more difficult and expensive to sell commercial paper or make other short-term borrowings.

Revenue bonds are issued by the DBF to finance capital improvement projects of HECO and its subsidiaries, but the source of their repayment are the unsecured obligations of HECO and its subsidiaries under loan agreements and notes issued to the DBF, including HECO s guarantees of its subsidiaries obligations. The payment of principal and interest due on all SPRBs outstanding as of September 30, 2009 and issued prior to 2009 are insured either by Ambac Assurance Corporation (Ambac), Financial Guaranty Insurance Company (FGIC), MBIA Insurance Corporation (MBIA) or Syncora Guarantee Inc. (Syncora) (formerly XL Capital Assurance Inc.). The insured outstanding revenue bonds were initially issued with S&P and Moody s ratings of AAA and Aaa, respectively, based on the ratings at the time of issuance of the applicable bond insurer. Beginning in 2008, however, ratings of Ambac, MBIA, FGIC and XLCA (now Syncora) were downgraded and/or withdrawn by S&P and Moody s resulting in a downgrade of the bond ratings of all of the bonds as shown in the ratings table above. The $150 million of SPRBs sold by the DBF for the benefit of HECO and HELCO on July 30, 2009, were sold without bond insurance. Management believes that if HECO s long-term credit ratings were to be downgraded, or if credit markets further tighten, it could be even more difficult and/or expensive to sell bonds in the future.

Operating activities provided $152 million in net cash during the first nine months of 2009. Investing activities during the same period used net cash of $230 million for capital expenditures, net of contributions in aid of construction. Financing activities for the same period provided net cash of $77 million, primarily due to drawdown of $153 million of SPRB proceeds, partly offset by the payment of $34 million of common and preferred dividends, a $31 million net decrease in short-term borrowings and a $10 million decrease in cash overdraft.

The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO. In October 2008, HECO, HELCO and MECO filed an application with the PUC for approval of one or more SPRB financings under the 2007 legislative authorization identified in the table above (up to $260 million for HECO, up to $115 million for HELCO, and up to $25 million for MECO). On June 29, 2009, the PUC granted the approvals necessary to permit the electric utilities to borrow the proceeds from the issuance of the SPRBs in the amounts requested. On July 30, 2009, the DBF issued (pursuant to the 2007 legislative authorization), at par, Series 2009 SPRBs in the aggregate principal amount of $150 million, which bonds are uninsured, with a maturity of July 1, 2039 and a fixed coupon interest rate of 6.50%, and loaned the proceeds to HECO ($90 million) and HELCO ($60 million). As of September 30, 2009, HECO and HELCO had drawn the full amount of the proceeds from the issuance of the SPRBs as reimbursement for previously incurred capital expenditures and had used the proceeds principally to repay short-term borrowings.

On April 20, 2009, HECO, HELCO and MECO filed with the PUC an application for the approval of the sale of each company s common stock (HECO s sale to HEI of up to $120 million and HELCO s and MECO s sales to HECO of up to $30 million and $7 million, respectively), and the purchase of the HELCO and MECO common stock by HECO, all in 2009. In October 2009, the PUC approved the utilities sale of common stock up to the amounts requested by each utility, but subject to the limitation that the issuance not result in the utility exceeding the percentage of common stock used to calculate the capital structure approved for ratemaking purposes in the utility s most recent rate case. HEI expects to contribute approximately $100 million of equity to HECO by December 31, 2009.

HECO s consolidated 2009 gross capital expenditures are now estimated to be approximately $380 million, reflecting a $37 million increase from the 2009 gross capital expenditures included in the previous five-year (2009-2013) consolidated utility forecast of $1.6 billion. The increase primarily reflects the higher cost estimate for CIP CT-1.

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Bank

RESULTS OF OPERATIONS

(in thousands)	Three months ended September 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 71,947	$ 87,675	(18)	Lower interest income primarily due to lower earning asset balances (due to repayments on the mortgage-related securities portfolio and the strategic decision to sell all salable residential loans) and lower yields on earning assets (due to the lower interest rate environment) and lower noninterest income due to OTTI charges on the mortgage-related securities portfolio
Operating income	17,689	24,692	(28)	Lower net interest income, higher provision for loan losses and lower noninterest income, partly offset by lower noninterest expense
Net income	11,323	15,405	(26)	Lower operating income

(in thousands)	Nine months ended September 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 229,478	$ 279,469	(18)	Lower interest income primarily due to lower earning asset balances (as a result of the balance sheet restructuring in June 2008 and due to repayments on the mortgage-related securities portfolio and to the strategic decision to sell all salable residential loans) and lower yields on earning assets (due to the lower interest rate environment), partly offset by higher noninterest income (due to prior year losses on the sale of investment and mortgage-related securities resulting from the balance sheet restructuring, partly offset by OTTI charges)
Operating income	40,316	17,063	136	Higher noninterest income due to losses in 2008 on the sale of investment and mortgage-related securities resulting from the balance sheet restructuring and lower noninterest expense due to the loss on early extinguishment of debt from the balance sheet restructuring, partly offset by higher provision for loan losses and lower net interest income in 2009
Net income	26,226	11,888	121	Higher operating income due to charges for the balance sheet restructure in 2008

See Economic conditions in the HEI Consolidated section above.

Average balance sheet and net interest margin. The following tables set forth average balances, together with interest and dividend income earned and accrued, and resulting yields and costs for the three and nine months ended September 30, 2009 and 2008. The average balances for investment and mortgage-related securities and other borrowings for the nine months ended September 30, 2009 were lower due to the balance sheet restructuring in June 2008, repayments on the mortgage-related securities portfolio and the strategic decision to sell all salable residential loans. The average rate for other borrowings was also impacted by the balance sheet restructure.

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	Three months ended September 30					
	2009			2008		
($ in thousands)	Average Balance	Interest	Average Rate (%)	Average Balance	Interest	Average Rate (%)
Assets:						
Other investments [1]	$ 270,177	$ 122	0.18	$ 108,818	$ 392	1.44
Investment and mortgage-related securities	662,419	6,821	4.12	868,530	9,506	4.38
Loans receivable [2]	3,845,469	53,080	5.51	4,156,656	61,100	5.87
Total interest-earning assets	4,778,065	60,023	5.01	5,134,004	70,998	5.52
Allowance for loan losses	(43,792)			(30,334)		
Non-interest-earning assets	346,107			423,057		
Total assets	$ 5,080,380			$ 5,526,727		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,279,477	1,289	0.22	$ 2,093,666	2,735	0.52
Time certificates	1,083,713	5,997	2.20	1,425,334	11,335	3.16
Total interest-bearing deposits	3,363,190	7,286	0.86	3,519,000	14,070	1.59
Other borrowings	397,327	2,205	2.17	647,718	4,616	2.80
Total interest-bearing liabilities	3,760,517	9,491	1.00	4,166,718	18,686	1.77
Non-interest bearing liabilities:						
Deposits	749,328			701,062		
Other	88,775			103,235		
Stockholder s equity	481,760			555,712		
Total Liabilities and Stockholder s Equity	$ 5,080,380			$ 5,526,727		
Net interest income		$ 50,532			$ 52,312	
Net interest margin (%) [3]			4.23			4.08

	Nine months ended September 30					
	2009			2008		
($ in thousands)	Average Balance	Interest	Average Rate (%)	Average Balance	Interest	Average Rate (%)
Assets:						
Other investments [1]	$ 202,570	$ 177	0.12	$ 130,905	$ 1,538	1.56
Investment and mortgage-related securities	660,450	21,585	4.36	1,647,451	55,540	4.50
Loans receivable [2]	3,999,395	166,535	5.56	4,163,427	186,312	5.97
Total interest-earning assets	4,862,415	188,297	5.17	5,941,783	243,390	5.46
Allowance for loan losses	(41,252)			(30,134)		
Non-interest-earning assets	345,201			419,025		
Total assets	$ 5,166,364			$ 6,330,674		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,200,539	5,434	0.33	$ 2,100,710	9,052	0.57
Time certificates	1,214,775	23,319	2.57	1,499,492	38,857	3.45

Total interest-bearing deposits	3,415,314	28,753	1.13	3,600,202	47,909	1.77
Other borrowings	453,738	7,710	2.24	1,363,097	40,030	3.91
Total interest-bearing liabilities	3,869,052	36,463	1.26	4,963,299	87,939	2.36
Non-interest bearing liabilities:						
Deposits	733,810			681,198		
Other	87,455			105,473		
Stockholder s equity	476,047			580,704		
Total Liabilities and Stockholder s Equity	$ 5,166,364			$ 6,330,674		
Net interest income		$ 151,834			$ 155,451	
Net interest margin (%) [3]			4.17			3.49

[1] Includes federal funds sold, interest bearing deposits and stock in the FHLB of Seattle ($98 million as of September 30, 2009).

[2] Includes loan fees of $1.5 million and $1.0 million for the three months ended September 30, 2009 and 2008, respectively, $5.3 million and $3.4 million for the nine months ended September 30, 2009 and 2008, respectively together with interest accrued prior to suspension of interest accrual on nonaccrual loans. Includes nonaccrual loans.

[3] Defined as net interest income as a percentage of average earning assets.

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Earning assets, costing liabilities and other factors. Earnings of ASB depend primarily on net interest income, which is the difference between interest earned on earning assets and interest paid on costing liabilities. The current interest rate environment is impacted by disruptions in the financial markets and these conditions may have a negative impact on ASB s net interest margin.

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

Loan portfolio. ASB s loan volumes and yields are affected by market interest rates, competition, demand for financing, availability of funds and management s responses to these factors. The following table sets forth the composition of ASB s loan portfolio as of the dates indicated:

	September 30, 2009		December 31, 2008	
(dollars in thousands)	**Balance**	**% of total**	**Balance**	**% of total**
Real estate loans:				
Residential 1-4 family	$ 2,402,868	63.2	$ 2,808,611	66.2
Commercial real estate	257,711	6.8	242,952	5.7
Home equity line of credit	316,922	8.3	272,505	6.4
Residential land	107,735	2.8	126,963	3.0
Commercial construction	62,326	1.6	71,518	1.7
Residential construction	20,428	0.5	34,458	0.8
Total real estate loans, net	3,167,990	83.2	3,557,007	83.8
Commercial	553,417	14.6	594,677	14.0
Consumer	83,389	2.2	90,606	2.2
	3,804,796	100.0	4,242,290	100.0
Less: Allowance for loan losses	45,898		35,798	
Total loans, net	$ 3,758,898		$ 4,206,492	

The decrease in the total loan portfolio during the first nine months of 2009 was primarily due to ASB s strategic decision to sell all salable residential loans in the current low interest rate environment.

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

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

(dollars in thousands)	September 30, 2009	December 31, 2008
Real estate loans:		
Residential 1-4 family	$ 30,827	$ 7,335
Commercial real estate	284	
Home equity line of credit	2,391	716
Residential land	21,002	7,458
Commercial construction		
Residential construction	205	189
	54,709	15,698
Commercial	1,368	2,801
Consumer	590	488
Total nonperforming loans	56,667	18,987
Real estate owned:		
Residential 1-4 family	2,255	
Residential land	2,739	1,492
Total real estate owned loans	4,994	1,492
Total nonperforming assets	$ 61,661	$ 20,479
Nonperforming assets to total loans and REO	1.61%	0.48%

The increase in nonperforming loans was primarily due to higher amounts of residential first mortgage and land loans that are 90 days or more past due.

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

	September 30, 2009		December 31, 2008	
(dollars in thousands)	Balance	% of total	Balance	% of total
Real estate loans:				
Residential 1-4 family	$ 11,053	63.2	$ 4,024	66.2
Commercial real estate	3,402	8.4	3,977	7.4
Home equity line of credit	3,003	8.3	548	6.4
Residential land	7,447	2.8	1,953	3.0
Residential construction	157	0.5	88	0.8
Total real estate loans, net	25,062	83.2	10,590	83.8
Commercial	17,723	14.6	22,294	14.0
Consumer	2,524	2.2	2,190	2.2
	45,309	100.0	35,074	100.0
Unallocated	589		724	

Total allowance for loan losses	$ 45,898	$ 35,798

The increase in the allowance for loan losses was primarily due to higher residential first mortgage and land loans and home equity lines of credit delinquencies, offset by the partial charge-off of a commercial credit.

Investment and mortgage-related securities. As of September 30, 2009, the bank s investment portfolio consisted of 53% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), 36% private-issue mortgage-related securities, 10% federal agency obligations and 1% municipal bonds. As of December 31, 2008, the bank s investment portfolio consisted of 46% mortgage-related securities issued by FNMA, FHLMC or GNMA, 45% private-issue mortgage-related securities and 9% federal agency obligations.

Principal and interest on mortgage-related securities issued by FNMA, FHLMC and GNMA are guaranteed by the issuer, and the securities carry implied AAA ratings. Private-issue mortgage-related securities carry a risk of loss due to delinquencies, foreclosures, and losses in the mortgage loans collateralizing the securities. Further

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deterioration in the U.S. residential housing market continues to pressure the private-issue mortgage-related securities held in the investment portfolio. The velocity of economic decline has exacerbated already weak home sales, which are impacted by borrowers unable to secure financing but also by those defaulting on current loans as a result of unemployment trends or payment shocks. The flood of inventory as a result of foreclosures has pressured prices and thus the credit of securities held in the portfolio. Those originated within the last 2-3 years have experienced the greatest pressure as borrowers purchasing homes at the peak of the market have experienced price declines that have eroded any remaining equity in their properties. As of September 30, 2009, private-issue mortgage-related securities represented 36% of the portfolio. 18% of the portfolio was rated non-investment grade by at least one of the major rating agencies. While the majority of those securities are backed by prime, fixed rate, 30 year mortgages, price declines coupled with increased economic pressure have impacted all sectors of the housing market which has impacted credit ratings of securities backed by loans issued within the last couple of years.

The table below summarizes the private-issue mortgage-related securities by credit rating and year of issuance.

September 30, 2009

Private-issue mortgage-related securities [1]	Book value AAA/Aaa	AA+/AA/ AA-	A+/A/A-	BBB/Baa	BB+/BB/ BB-	B/B-	CCC+/ CCC	CC/Ca	C	Total	Net unrealized loss
(in thousands)											
Prime year of issuance:											
2003 and earlier	$ 37,696	$ 47	$ 916	$	$	$ 62	$ 204[2]	$	$	$ 38,925	$ (1,926)
2004	17,254	7,656								24,910	(778)
2005	3,722	28,500	9,313	8,032	11,883	12,085				73,535	(11,157)
2006						6,719[3]	45,577[4]		7,688[5]	59,984	(9,725)
2007									9,494[6]	9,494	(772)
Total prime	58,672	36,203	10,229	8,032	11,883	18,866	45,781		17,182	206,848	(24,358)
Alt-A year of issuance:											
2005							11,379[7]			11,379	(2,227)
2006								12,976[8]		12,976	(5,233)
Total Alt-A							11,379	12,976		24,355	(7,460)
Sub-prime year of issuance:											
1999 and earlier			1,443			279[9]				1,722	(185)
Total sub-prime			1,443			279				1,722	(185)
	$ 58,672	$ 36,203	$ 11,672	$ 8,032	$ 11,883	$ 19,145	$ 57,160	$ 12,976	$ 17,182	$ 232,925	$ (32,003)

1 All issues categorized by lowest available rating by Nationally Recognized Statistical Rating Organizations.
2 Includes one issue rated CCC+ by Moody s, with no OTTI credit loss taken in third quarter 2009.
3 Includes two issues rated B- by Moody s and S&P, with a realized OTTI credit loss of $0.2 million.
4 Includes four issues rated CCC by S&P and Fitch, with a realized OTTI credit loss of $0.2 million.
5 Includes one issue rated C by Fitch, with a realized OTTI credit loss of $3.5 million.
6 Includes one issue rated C by Fitch, with a realized OTTI credit loss of $3.0 million.
7 Includes one issue rated CCC by Fitch, with a realized OTTI credit loss of $0.1 million.
8 Includes one issue rated CC by Fitch, with a realized OTTI credit loss of $0.7 million.
9 Includes one issue rated B by Fitch, with a realized OTTI credit loss of $2.2 million.

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December 31, 2008

Private-issue mortgage-related securities [1] (in thousands)	Book value AAA/Aaa	AA/Aa	A	BBB/Baa	BB+/Ba	B	Total	Net unrealized loss
Prime year of issuance:								
2003 and earlier	$ 54,062	$ 300[2]	$ 2,732	$ 66	$	$	$ 57,160	$ (3,737)
2004	62,356						62,356	(4,089)
2005	100,061						100,061	(14,950)
2006			22,415	45,334	4,321	15,682	87,752	(25,429)
2007						12,042[3]	12,042	
Total prime	216,479	300	25,147	45,400	4,321	27,724	319,371	(48,205)
Alt-A year of issuance:								
2005			13,722				13,722	(3,315)
2006					14,300		14,300	(5,921)
Total Alt-A								