TUCOWS INC /PA/
Form 10-Q
November 07, 2018

Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2018

OR

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

For the transition period from to

Commission file number 1-32600

TUCOWS INC.

(Exact Name of Registrant as Specified in Its Charter)

Pennsylvania **23-2707366**

(State or Other Jurisdiction of Incorporation or Organization) (I.R.S. Employer Identification No.)

96 Mowat Avenue,

Toronto, Ontario M6K 3M1, Canada

(Address of Principal Executive Offices) (Zip Code)

(416) 535-0123

(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant: (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 No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company
	Emerging Growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act): Yes No

As of November 6, 2018, there were 10,615,925 outstanding shares of common stock, no par value, of the registrant.

Table of Contents

TUCOWS INC.

Form 10-Q Quarterly Report

INDEX

TRADEMARKS, TRADE NAMES AND SERVICE MARKS

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Table of Contents

PART I.

FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements

Tucows Inc.

Consolidated Balance Sheets

(Dollar amounts in thousands of U.S. dollars)

(unaudited)

	September 30, 2018	**December 31, 2017***
Assets		
Current assets:		
Cash and cash equivalents	$ 10,775	$ 18,049
Accounts receivable, net of allowance for doubtful accounts of $132 as of September 30, 2018 and $168 as of December 31, 2017	11,529	12,376
Inventory	3,140	2,944
Prepaid expenses and deposits	14,554	14,186
Prepaid domain name registry and ancillary services fees, current portion (note 11 (b))	91,590	103,302
Income taxes recoverable	3,109	3,004
Total current assets	134,697	153,861
Prepaid domain name registry and ancillary services fees, long-term portion (note 11 (b))	19,636	23,701
Property and equipment	40,220	24,620
Contract costs (note 11 (a))	1,383	-
Intangible assets (note 6)	51,505	58,414
Goodwill (note 6)	90,054	90,054
Total assets	$ 337,495	$ 350,650
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 8,242	$ 7,026
Accrued liabilities	6,877	6,412
Customer deposits	11,885	15,255
Derivative instrument liability (note 5)	62	-

Deferred rent, current portion	21	21
Loan payable, current portion (note 7)	17,810	18,290
Deferred revenue, current portion	120,459	129,155
Accreditation fees payable, current portion	1,035	1,175
Income taxes payable	1,128	1,226
Total current liabilities	167,519	178,560
Deferred revenue, long-term portion	28,033	31,427
Accreditation fees payable, long-term portion	260	289
Deferred rent, long-term portion	121	130
Loan payable, long-term portion (note 7)	46,605	58,634
Deferred gain	258	429
Deferred tax liability (note 8)	19,265	19,834
Redeemable non-controlling interest (note 4 (a))	-	1,136
Stockholders' equity (note 13)		
Preferred stock - no par value, 1,250,000 shares authorized; none issued and outstanding	-	-
Common stock - no par value, 250,000,000 shares authorized; 10,615,566 shares issued and outstanding as of September 30, 2018 and 10,583,879 shares issued and outstanding as of December 31, 2017	15,635	15,368
Additional paid-in capital	3,462	2,167
Retained earnings	56,373	42,676
Accumulated other comprehensive income	(36)	-
Total stockholders' equity	75,434	60,211
Total liabilities and stockholders' equity	$ 337,495	$ 350,650

Commitments and contingencies (note 16)

*The Company has initially applied ASC 2014-09 (Topic 606) using the modified retrospective method. Under this method, the comparative information is not restated.

See accompanying notes to unaudited consolidated financial statements

Table of Contents

Tucows Inc.

Consolidated Statements of Operations and Comprehensive Income

(Dollar amounts in thousands of U.S. dollars, except per share amounts)

(unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2018	**2017**	**2018**	**2017**
Net revenues (note 10)	$83,519	$85,008	$260,401	$238,800
Cost of revenues (note 10)				
Cost of revenues	55,105	60,731	178,578	169,488
Network expenses	2,315	2,461	7,590	7,064
Depreciation of property and equipment	1,339	823	3,698	2,128
Amortization of intangible assets (note 6)	499	499	1,497	1,335
Total cost of revenues	59,258	64,514	191,363	180,015
Gross profit	24,261	20,494	69,038	58,785
Expenses:				
Sales and marketing	8,412	7,384	24,629	22,051
Technical operations and development	2,207	1,910	6,657	5,402
General and administrative	4,120	3,381	12,906	10,124
Depreciation of property and equipment	106	155	309	486
Amortization of intangible assets (note 6)	1,797	1,746	5,456	4,735
Impairment of indefinite life intangible assets (note 6)	-	2		2
Loss (gain) on currency forward contracts (note 5)	(27)	(54)	22	(115)
Total expenses	16,615	14,524	49,979	42,685
Income from operations	7,646	5,970	19,059	16,100
Other income (expenses):				
Interest expense, net	(914)	(864)	(2,761)	(2,703)
Other income, net	(16)	157	181	512
Total other income (expenses)	(930)	(707)	(2,580)	(2,191)
Income before provision for income taxes	6,716	5,263	16,479	13,909
Provision for income taxes (note 8)	1,370	1,823	3,781	2,781

Net income before redeemable non-controlling interest	5,346	3,440	12,698	11,128
Redeemable non-controlling interest	-	(69)	(26)	(312)
Net income attributable to redeemable non-controlling interest	-	69	26	312
Net income for the period	5,346	3,440	12,698	11,128
Other comprehensive income, net of tax				
Unrealized income (loss) on hedging activities (note 5)	144	309	(112)	638
Net amount reclassified to earnings (note 5)	63	(318)	76	(416)
Other comprehensive income (loss) net of tax of $ (59) and $ 5 for the three months ended September 30, 2018 and September 30, 2017, $ 19 and $ (127) for the nine months ended September 30, 2018 and September 30, 2017 (note 5)	207	(9)	(36)	222
Comprehensive income, net of tax for the period	$ 5,553	$ 3,431	$ 12,662	$ 11,350
Basic earnings per common share (note 9)	$ 0.50	$ 0.33	$ 1.20	$ 1.06
Shares used in computing basic earnings per common share (note 9)	10,611,579	10,564,311	10,599,243	10,522,841
Diluted earnings per common share (note 9)	$ 0.50	$ 0.32	$ 1.18	$ 1.03
Shares used in computing diluted earnings per common share (note 9)	10,794,297	10,785,342	10,795,668	10,785,050

*The Company has initially applied ASC 2014-09 (Topic 606) using the modified retrospective method. Under this method, the comparative information is not restated.

See accompanying notes to unaudited consolidated financial statements

4

Table of Contents

Tucows Inc.

Consolidated Statements of Cash Flows

(Dollar amounts in thousands of U.S. dollars)

(unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2018	**2017**	**2018**	**2017**
Cash provided by:				
Operating activities:				
Net income for the period	$5,346	$3,440	$12,698	$11,128
Items not involving cash:				
Depreciation of property and equipment	1,445	978	4,007	2,614
Loss on write off of property and equipment	-	8	-	17
Amortization of debt discount and issuance costs	72	57	211	204
Amortization of intangible assets	2,296	2,245	6,953	6,070
Impairment of indefinite life intangible asset	-	2	-	2
Change in capitalized contract costs	(29)	-	21	-
Deferred income taxes (recovery)	(369)	(1,445)	(861)	(3,011)
Excess tax benefits on share-based compensation expense	(191)	(444)	(532)	(2,615)
Amortization of deferred rent	(5)	-	(9)	6
Loss on disposal of domain names	5	8	70	25
Other income	-	(129)	(171)	(386)
Loss (gain) on change in the fair value of forward contracts	(30)	1	13	(37)
Stock-based compensation	711	203	1,904	834
Change in non-cash operating working capital:				
Accounts receivable	685	533	847	(332)
Inventory	108	(643)	(196)	(1,739)
Prepaid expenses and deposits	874	202	(368)	(2,169)
Prepaid domain name registry and ancillary services fees	4,229	3,084	15,777	570
Income taxes recoverable	(137)	2,225	293	1,815
Accounts payable	778	(644)	1,048	(4,682)
Accrued liabilities	107	981	465	994
Customer deposits	(1,049)	(1,905)	(3,370)	1,163
Deferred revenue	(3,559)	(1,425)	(12,090)	7,543
Accreditation fees payable	(73)	(50)	(169)	(200)
Net cash provided by operating activities	11,214	7,282	26,541	17,814
Financing activities:				
Proceeds received on exercise of stock options	23	68	62	173
Payment of tax obligations resulting from net exercise of stock options	(116)	(117)	(404)	(1,438)

Proceeds received on loan payable	-	-	2,500	86,998
Repayment of loan payable	(4,387)	(4,573)	(15,212)	(15,403)
Payment of loan payable costs	(4)	(16)	(8)	(620)
Net cash (used in) provided by financing activities	(4,484)	(4,638)	(13,062)	69,710
Investing activities:				
Additions to property and equipment	(7,003)	(2,859)	(19,439)	(9,461)
Acquisition of a portion of the minority interest in Ting Virginia, LLC (note 4(a))	-	-	(1,200)	(2,000)
Acquisition of Enom Incorporated, net of cash (note 4(b))	-	-	-	(76,237)
Acquisition of intangible assets	(113)	(2,384)	(114)	(2,384)
Net cash used in investing activities	(7,116)	(5,243)	(20,753)	(90,082)
Decrease in cash and cash equivalents	(386)	(2,599)	(7,274)	(2,558)
Cash and cash equivalents, beginning of period	11,161	15,146	18,049	15,105
Cash and cash equivalents, end of period	$10,775	$12,547	$10,775	$12,547
Supplemental cash flow information:				
Interest paid	$919	$870	$2,781	$2,717
Income taxes paid, net	$1,793	$1,308	$5,370	$6,313
Supplementary disclosure of non-cash investing and financing activities:				
Property and equipment acquired during the period not yet paid for	$382	$186	$382	$186

*The Company has initially applied ASC 2014-09 (Topic 606) using the modified retrospective method. Under this method, the comparative information is not restated.

See accompanying notes to unaudited consolidated financial statements

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Organization of the Company:

Tucows Inc. (referred to throughout this report as the "Company", "Tucows", "we", "us" or through similar expressions) provides simple useful services that help people unlock the power of the Internet. The Company provides U.S. consumers and small businesses with mobile phone services nationally and high-speed fixed Internet access in selected towns. The Company is also a global distributor of Internet services, including domain name registration, digital certificates, and email. It provides these services primarily through a global Internet-based distribution network of Internet Service Providers, web hosting companies and other providers of Internet services to end-users.

2. Basis of presentation:

The accompanying unaudited interim consolidated balance sheets, and the related consolidated statements of operations and comprehensive income and cash flows reflect all adjustments, consisting of normal recurring adjustments, that are, in the opinion of management, necessary for a fair presentation of the financial position of Tucows and its subsidiaries as at September 30, 2018 and the results of operations and cash flows for the interim periods ended September 30, 2018 and 2017. The results of operations presented in this Quarterly Report on Form 10-Q are not necessarily indicative of the results of operations that may be expected for future periods.

The accompanying unaudited interim consolidated financial statements have been prepared by Tucows in accordance with the rules and regulations of the United States Securities and Exchange Commission (the "SEC"). Certain information and footnote disclosures normally included in the Company's annual audited consolidated financial statements and accompanying notes have been condensed or omitted. Other than the exception noted below, these interim consolidated financial statements and accompanying notes follow the same accounting policies and methods of application used in the annual financial statements and should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2017 included in Tucows' 2017 Annual Report on Form 10-K filed with the SEC on March 6, 2018 (the "2017 Annual Report"). There have been no material changes to our significant accounting policies and estimates during the nine months ended September 30, 2018 as compared to the significant accounting policies and estimates described in our 2017 Annual Report, except for the adoption of Accounting Standards Update ("ASU") No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* ("ASU 2014-09"). See note 3 – Recent accounting pronouncements for more information.

Beginning with the Company’s Quarterly Report on Form 10-Q ended June 30, 2018 filed with the SEC August 8, 2018, all dollar values of current and comparative figures in the financial statements and accompanying tables have been rounded to the nearest thousand ($000), except when otherwise indicated.

During the preparation of these interim financial statements, the Company identified an immaterial error that affects the classification of expenses for the three and nine months ended September 30, 2017. This correction of the comparative periods resulted in a decrease in cost of revenues of $0.3 million, a decrease in sales and marketing expense of $0.2 million, and an increase in general and administrative expenses of $0.5 million for both the three and nine months ended September 30, 2017 compared to the amounts previously reported.

3. Recent accounting pronouncements:

Recent Accounting Pronouncements Adopted

On January 1, 2018, the Company adopted Accounting Standards Updates ("ASU") No. 2017-01, *Business Combinations (Topic* 805*): Clarifying the Definition of a Business* and ASU 2015-16, *Simplifying the Accounting for Measurement-Period Adjustments.* The adoption of these updates did not have a significant impact on the consolidated financial statements. We also adopted ASU 2014-09 on January 1, 2018. The impact of such adoption is described in more detail below.

ASU 2014-09: *Adoption of Revenue from Contracts with Customers (Topic* 606*)*

On January 1, 2018, the Company adopted ASU 2014-09 using the modified retrospective method by recognizing the cumulative effect of initially applying ASU 2014-09 as an adjustment to the opening balance of equity as at January 1, 2018. The results for reporting periods beginning after January 1, 2018 are presented under ASU 2014-09, while prior period amounts are not adjusted and continue to be reported in accordance with our historic accounting policy, under Accounting Standards Codification (“ASC”) Topic 605, Revenue Recognition (ASC Topic 605). The adoption of ASU 2014-09 did not affect the Company’s cash flows from operating, investing, or financing activities. Furthermore, the impact on timing of revenue recognition was not material as the treatment of revenue for services rendered over time is consistent under ASU 2014-09 and ASC Topic 605. The details of the significant changes and quantitative impact of the changes are set out below. For a more comprehensive description of how the Company recognizes revenue under the new revenue standard in accordance with its performance obligations, see note 10 – Revenue for more information.

The Company previously recognized commission fees related to Ting Mobile, Ting Internet, eNom domain registration and eNom domain related value-added service contracts as selling expenses when they were incurred.

Under ASU 2014-09, when these commission fees are deemed incremental and are expected to be recovered, the Company capitalizes as an asset such commission fees as costs of obtaining a contract. These commission fees are amortized into income consistently with the pattern of transfer of the good or service to which the asset relates. The amortization of deferred costs of acquisition are amortized into Sales and marketing expense. The estimation of the amortization period for the costs to obtain a contract requires judgement.

Table of Contents

Under ASU 2014-09, the Company has applied the following practical expedients

a) When the amortization period for costs incurred to obtain a contract with a customer is less than one year, the Company has elected to apply a practical expedient to expense the costs as incurred; and

b) For mobile and internet access services, where the performance obligation is part of contracts that have an original expected duration of one year or less (typically one month), the Company has elected to apply a practical expedient to not disclose revenues expected to be recognized in the future related performance obligations that are unsatisfied (or partially unsatisfied).

On January 1, 2018 as a result of adopting ASU 2014-09, the Company recorded a contract cost asset of $1.4 million with a corresponding increase to opening retained earnings and deferred tax liability of $1.1 million and $0.3 million, respectively, due to the deferral of costs of obtaining contracts.

The impact of the changes to the Company's financial statements in the current period are as follows *(Dollar amounts in thousands of U.S. dollars)*:

	September 30, 2018		
Consolidated Balance Sheet	**As reported**	**Adjustments**	**Balances without adoption of Topic 606**
Assets			
Contract Costs (note 11(a))	$1,383	$ (1,383)	$-
Total assets	337,495	$ (1,383)	$336,112
Liabilities and Shareholders' Equity			
Deferred tax liability (note 8)	$19,265	$ (336)	$18,929
Retained earnings	56,373	(1,047)	55,326
Total Liabilities and Shareholders' Equity	$337,495	$ (1,383)	$336,112

	Three months ended, September 30, 2018			**Nine months ended, September 30, 2018**		
			Balances without			**Balances without**

Consolidated Statements of Operations and Comprehensive Income	As reported	Adjustments		adoption of Topic 606	As reported	Adjustments		adoption of Topic 606
Expenses								
Sales and marketing	$8,412	$ 29		$ 8,441	$24,629	$ (21	)	$24,608
Income before provision for income taxes	6,716	(29	)	6,687	16,479	21		16,500
Provision for income taxes (note 8)	1,370	(7	)	1,363	3,781	5		3,786
Net income for the period	$5,346	$ (22	)	$ 5,324	$12,698	$ 16		$12,714

7

Table of Contents

Consolidated Statements of Cash Flows	**Three months ended, September 30, 2018**			**Nine months ended, September 30, 2018**		
	As reported	**Adjustments**	**Balances without adoption of Topic 606**	**As reported**	**Adjustments**	**Balances without adoption of Topic 606**
Net income for the period	$5,346	$ (22)	$5,324	$12,698	$ 16	$12,714
Items not involving cash						
Amortization contract costs	(29)	29	(0)	21	(21)	-
Deferred income taxes (recovery)	(369)	(7)	(376)	(861)	5	(856)
Net cash provided by operating activities	11,214	$ -	$11,214	$26,541	$ -	$26,541

Recent Accounting Pronouncements Not Yet Adopted

In August 2018, the Financial Accounting Standards Board ("FASB") issued ASU No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software* (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement ("ASU 2018-15"). ASU 2018-15 helps entities evaluate the accounting for fees paid by a customer in a cloud computing arrangement (hosting arrangement) by providing guidance on accounting for implementation costs when the cloud computing arrangement does not include a licence and is accounted for as a service contract. The amendments in ASU 2018-15 require an entity (customer) in a hosting arrangement to assess which implementation costs to capitalize vs expense as it relates to a service contract. The amendments also require the entity (customer) to expense the capitalized implementation costs of a hosting arrangement that is a service contract over the term of the hosting arrangement. ASU 2018-15 will be effective for the Company for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. The Company is currently in the process of evaluating the quantitative impact of this Update, and transition methods.

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic* 842*)* ("ASU 2016-02"). ASU 2016-02 requires lessees to recognize the assets and liabilities that arise from leases on the balance sheet. More specifically, ASU 2016-02 requires the recognition on the balance sheet of a lease liability to make lease payments by lessees and a right-of-use asset representing its right to use the underlying asset for the lease term. The new guidance will also require significant additional disclosure about the amount, timing and uncertainty of cash flows from leases. The new guidance is effective for annual and interim reporting periods beginning after December 15, 2018, which begins on January 1, 2019 for the Company. The amendments should be applied at the beginning of the earliest period presented using a modified retrospective approach with earlier application permitted as of the beginning of an interim or annual reporting period. The Company will adopt this guidance in the first quarter of fiscal 2019. The Company is currently in the process of evaluating the impact of transition methods. While we are continuing to assess all potential impacts of the standard, we currently believe the most significant impact relates to our accounting for administrative office operating leases.

4. Acquisitions:

(a) Blue Ridge Websoft

On February 27, 2015, Ting Fiber, Inc. (“Ting”), one of the Company’s wholly owned subsidiaries, acquired a 70% ownership interest in Ting Virginia, LLC and its subsidiaries, Blue Ridge Websoft, LLC (doing business as Blue Ridge Internet Works), Fiber Roads, LLC and Navigator Network Services, LLC for consideration of approximately $3.5 million.

On February 1, 2017, under the terms of a call option in the agreement, Ting acquired an additional 20% interest in Ting Virginia, LLC from the selling shareholders (the “Minority Shareholders”) for consideration of $2.0 million.

On February 13, 2018, the Company entered into an agreement Minority Shareholders pursuant to which the Minority Shareholders could immediately exercise their put option to sell their remaining 10% ownership interest in Ting Virginia, LLC for $1.2 million to the Company. The put option was exercised on February 13, 2018 and the Company paid $1.2 million for the remaining 10% ownership interest and Ting Virginia, LLC became a wholly-owned subsidiary of the Company.

(b) eNom, Incorporated

On January 20, 2017, the Company entered into a Stock Purchase Agreement (the “Purchase Agreement”) with its indirect wholly owned subsidiary, Tucows (Emerald), LLC, Rightside Group, Ltd., and Rightside Operating Co., pursuant to which Tucows (Emerald), LLC purchased from Rightside Operating Co. all of the issued and outstanding capital stock of eNom, Incorporated (“eNom”), a domain name registrar business. The purchase price was $77.8 million, which represented the agreed upon purchase of $83.5 million less an amount of $5.7 million related to the working capital deficiency acquired.

5. Derivative instruments and hedging activities:

Foreign currency forward contracts

In October 2012, the Company entered into a hedging program with a Canadian chartered bank to limit the potential foreign exchange fluctuations incurred on its future cash flows related to a portion of payroll, rent, and payments to Canadian domain name registry suppliers that are denominated in Canadian dollars and are expected to be paid by its Canadian operating subsidiary. As part of its risk management strategy, the Company uses derivative instruments to hedge a portion of the foreign exchange risk associated with these costs. The Company does not use these forward contracts for trading or speculative purposes. These forward contracts typically mature between one and eighteen months.

The Company has designated certain of these transactions as cash flow hedges of forecasted transactions under ASC Topic 815, *Derivatives and Hedging* (“ASC Topic 815”). For certain contracts, as the critical terms of the hedging instrument and the entire hedged forecasted transaction are the same in accordance with ASC Topic 815, the Company has been able to conclude that changes in fair value and cash flows attributable to the risk of being hedged are expected to completely offset at inception and on an ongoing basis. Accordingly, unrealized gains or losses on the effective portion of these contracts have been included within other comprehensive income (“OCI”). The fair value of the contracts, as of September 30, 2018, is recorded as derivative instrument liabilities. For certain contracts where the hedged transactions are no longer probable to occur, the loss on the associated forward contract is reclassified from accumulated other comprehensive income (“AOCI”) to earnings.

As of September 30, 2018, the notional amount of forward contracts that the Company held to sell U.S. dollars in exchange for Canadian dollars was $10.7 million, of which $9.5 million were designated as hedges. As of December 31, 2017 the Company held no contracts to trade U.S. dollars in exchange for Canadian dollars.

As of September 30, 2018, we had the following outstanding forward exchange contracts to trade U.S. dollars in exchange for Canadian dollars:

Maturity date (Dollar amounts in thousands of U.S. dollars)	Notional amount of U.S. dollars	Weighted average exchange rate	Fair value

	of U.S. dollars		
October - December 2018	6,049	1.2802	(50)
January - March 2019	1,639	1.2852	(4)
April - June 2019	1,599	1.2831	(4)
July - September 2019	1,444	1.2809	(4)
	$ 10,731	1.2815	$ (62)

Fair value of derivative instruments and effect of derivative instruments on financial performance

The effect of these derivative instruments on our consolidated financial statements were as follows (amounts presented do not include any income tax effects).

Fair value of derivative instruments in the consolidated balance sheets

Derivatives (Dollar amounts in thousands of U.S. dollars)	**Balance Sheet Location**	**As of September 30, 2018 Fair Value Asset (Liability)**	**As of December 31, 2017 Fair Value Asset (Liability)**
Foreign currency forward contracts designated as cash flow hedges (net)	Derivative instruments	$ (55)	$ -
Foreign currency forward contracts not designated as cash flow hedges (net)	Derivative instruments	$ (7)	$ -
Total foreign currency forward contracts (net)	Derivative instruments	$ (62)	$ -

Movement in Accumulated Other Comprehensive Income ("AOCI") balance for the three months ended September 30, 2018 (Dollar amounts in thousands of U.S. dollars)*:*

	Gains and losses on cash flow hedges	Tax impact	Total AOCI
Opening AOCI balance – June 30. 2018	$ (321)	$ 78	$ (243)
Other comprehensive income (loss) before reclassifications	183	(39)	144
Amount reclassified from AOCI	83	(20)	63
Other comprehensive income (loss) for the three months ended September 30, 2018	266	(59)	207
Ending AOCI balance – September 30, 2018	$ (55)	$ 19	$ (36)

Movement in AOCI balance for the nine months ended September 30, 2018 (Dollar amounts in thousands of U.S. dollars)*:*

	Gains and losses on cash flow hedges	Tax impact	Total AOCI
Opening AOCI balance – December 31, 2017	$ —	$ —	$ —
Other comprehensive income (loss) before reclassifications	(155)	43	(112)
Amount reclassified from AOCI	100	(24)	76
Other comprehensive income (loss) for the nine months ended September 30, 2018	(55)	19	(36)
Ending AOCI balance – September 30, 2018	$ (55)	$ 19	$ (36)

Effects of derivative instruments on income and OCI for the three *months ended September* 30, 2018 *and September* 30, *2017 are as follows* (Dollar amounts in thousands of U.S. dollars):

Derivatives in Cash Flow Hedging Relationship	**Amount of Gain or (Loss) Recognized in OCI, net of tax, on Derivative (Effective Portion)**	**Location of Gain or (Loss) Reclassified from AOCI into Income (Effective Portion)**	**Amount of Gain or (Loss) Reclassified from AOCI into Income, (Effective Portion)**	**Location of Gain or (Loss) Recognized in Income on Derivative (ineffective Portion and Amount Excluded from Effectiveness Testing)**	**Amount of Gain or (Loss) Recognized in Income on Derivative (ineffective Portion and Amount Excluded from Effectiveness Testing)**
Foreign currency forward contracts for the three months ended September 30, 2018	$ 207	Operating expenses	$ (71)	Operating expenses	$ —
		Cost of revenues	$ (12)	Cost of revenues	—
Foreign currency forward contracts for the three months ended September 30, 2017	$ (9)	Operating expenses	$ 432	Operating expenses	$ —
		Cost of revenues	$ 66	Cost of revenues	—

10

Table of Contents

Effects of derivative instruments on income and other comprehensive income (OCI) for the nine months ended September 30, 2018 and September 30, 2017 are as follows (Dollar amounts in thousands of U.S. dollars):

Derivatives in Cash Flow Hedging Relationship	**Amount of Gain or (Loss) Recognized in OCI, net of tax, on Derivative (Effective Portion)**	**Location of Gain or (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**	**Amount of Gain or (Loss) Reclassified from Accumulated OCI into Income, (Effective Portion)**	**Location of Gain or (Loss) Recognized in Income on Derivative (ineffective Portion and Amount Excluded from Effectiveness Testing)**	**Amount of Gain or (Loss) Recognized in Income on Derivative (ineffective Portion and Amount Excluded from Effectiveness Testing)**
Foreign currency forward contracts for the nine months ended September 30, 2018		Operating expenses	$ (87)	Operating expenses	$ —
	$ (36)	Cost of revenues	$ (13)	Cost of revenues	—
Foreign currency forward contracts for the nine months ended September 30, 2017		Operating expenses	$ 561	Operating expenses	$ —
	$ 222	Cost of revenues	$ 91	Cost of revenues	—

In addition to the above, for those foreign currency forward contracts not designated as hedges, the Company recorded a loss on settlement of less than $0.1 million for the three months ended September 30, 2018 (gain of $0.1 million for the three months ended September 30, 2017) and a gain of less than $0.1 million for the change in fair value of outstanding contracts for the three months ended September 30, 2018 (loss of less than $0.1 million for the three months ended September 30, 2017), in the consolidated statement of operations and comprehensive income.

The Company has recorded a loss of less than $0.1 million upon settlement for the nine months ended September, 30 2018 (gain of $0.1 million for the nine months ended September 30, 2017) and a loss of less than $0.1 million for the change in fair value of outstanding contracts for the nine months ended September 30, 2018 (gain of less than $0.1 million for the nine months ended September 30, 2017), in the consolidated statement of operations and comprehensive income.

6. Goodwill and Other Intangible Assets:

Goodwill

Goodwill represents the excess of the purchase price over the fair value of tangible and identifiable intangible assets acquired and liabilities assumed in our acquisitions.

The Company's Goodwill balance is $90.1 million as of September 30, 2018 (December 31, 2017 – $90.1 million). The Company's goodwill relates 98% ($87.9 million) to its Domain Services operating segment and 2% ($2.2 million) to its Network Access Services operating segment.

Goodwill is not amortized, but is subject to an annual impairment test, or more frequently if impairment indicators are present.

Table of Contents

Other Intangible Assets:

Intangible assets consist of acquired brand, technology, customer relationships, surname domain names, direct navigation domain names and network rights. The Company considers its intangible assets consisting of surname domain names and direct navigation domain names as indefinite life intangible assets. The Company has the exclusive right to these domain names as long as the annual renewal fees are paid to the applicable registry. Renewals occur routinely and at a nominal cost. The indefinite life intangible assets are not amortized but are subject to impairment assessments performed throughout the year. As part of the normal renewal evaluation process during the periods ended September 30, 2018 and September 30, 2017, the Company assessed that certain domain names that were originally acquired in the June 2006 acquisition of Mailbank.com Inc. that were up for renewal, should be renewed.

Intangible assets, comprising brand, technology, customer relationships and network rights are being amortized on a straight-line basis over periods of four to fifteen years.

A summary of acquired intangible assets for the three months ended September 30, 2018 is as follows *(Dollar amounts in thousands of U.S. dollars)*:

	Surname domain names	**Direct navigation domain names**	**Brand**	**Customer relationships**	**Technology**	**Network rights**	**Total**
Amortization period	**indefinite life**	**indefinite life**	**7 years**	**4 - 7 years**	**2 years**	**15 years**	
Balances June 30, 2018	$ 11,201	$ 1,495	$ 9,892	$ 29,429	$ 1,138	$ 538	$ 53,693
Acquisition of customer relationships				113			113
Additions to/(disposals from) domain portfolio, net	(2)	(3)	-	-	-	-	(5)
Amortization expense	-	-	(446)	(1,351)	(488)	(11)	(2,296)
Balances September 30, 2018	$ 11,199	$ 1,492	$ 9,446	$ 28,191	$ 650	$ 527	$ 51,505

A summary of acquired intangible assets for the nine months ended September 30, 2018 is as follows *(Dollar amounts in thousands of U.S. dollars)*:

	Surname	**Direct**	**Brand**	**Customer relationships**	**Technology**	**Network**	**Total**

	domain names	navigation				rights	
		domain names					
Amortization period	**indefinite life**	**indefinite life**	**7 years**	**4 - 7 years**	**2 years**	**15 years**	
Balances December 31, 2017	$ 11,210	$ 1,551	$ 10,793	$ 32,186	$ 2,113	$ 561	$ 58,414
Acquisition of customer relationships	-	-	-	114	-	-	114
Additions to/(disposals from) domain portfolio, net	(11)	(59)	-	-	-	-	(70)
Amortization expense	-	-	(1,347)	(4,109)	(1,463)	(34)	(6,953)
Balances September 30, 2018	$ 11,199	$ 1,492	$ 9,446	$ 28,191	$ 650	$ 527	$ 51,505

The following table shows the estimated amortization expense in future periods, assuming no further additions to acquired intangible assets are made *(Dollar amounts in thousands of U.S. dollars)*:

	Year ending December 31,
Remainder of 2018	$ 2,285
2019	7,349
2020	7,187
2021	7,187
2022	7,187
Thereafter	7,619
Total	$ 38,814

As of September 30, 2018, the accumulated amortization for the definite life intangible assets was $22.3 million.

7. Loan payable:

2017 *Amended Credit Facility*

On January 20, 2017, the Company entered into an amended and restated secured Credit Agreement (the “2017 Amended Credit Agreement”) with Bank of Montreal (“BMO”), Royal Bank of Canada and Bank of Nova Scotia (collectively with “Lenders”) under which the Company increased its access to funds to an aggregate of $140 million. This amendment and restatement to the Company’s 2016 Credit Facility (defined below), among other things, reduced the existing Tucows non-revolving facility (such existing non-revolving facility, together with other existing facilities, the “Existing Facilities”) from $40.0 million to $35.5 million, and established a new non-revolving credit facility of $84.5 million (the “Facility D”). The Company immediately drew down $84.5 million under Facility D to fund the acquisition of eNom. See note 4 – Acquisitions for more information. The “2016 Credit Facility” refers to the credit facility established under the Company’s secured credit agreement among the Company, BMO and the Lenders, dated as of August 18, 2016.

In connection with the 2017 Amended Credit Agreement, the Company incurred $0.6 million of fees paid to lenders and debt issuance costs, which have been reflected as a reduction to the carrying amount of the loan payable and will be amortized over the term of the credit facility agreement.

The obligations of the Company under the 2017 Amended Credit Facility are secured by a first priority lien on substantially all of the personal property and assets of the Company.

The 2017 Amended Credit Facility has a four-year term. Under the 2017 Amended Credit Facility, the Company has access to an aggregate of up to $140 million in funds that are available as follows:

- a $5 million revolving credit facility ("Facility A");
- a $15 million revolving reducing term facility ("Facility B");
- a $35.5 million non-revolving facility ("Facility C"); and
- a $84.5 million non-revolving facility ("Facility D").

Borrowings under the 2017 Amended Credit Facility accrue interest and standby fees at variable rates based on borrowing elections by the Company and the Company's Total Funded Debt to EBITDA as described below. The purpose of Facility A is for general working capital and general corporate requirements, while Facility B and Facility C support share repurchases, acquisitions and capital expenditures associated with the Company's Fiber to the Home program ("FTTH"). Facility D was provided and used for the acquisition of eNom.

The repayment terms for Facility A require monthly interest payments with any final principal payment becoming due upon maturity of the 2017 Amended Credit Facility. Under the repayment terms for Facility B, at December 31st of each year, balances drawn during the year that remain outstanding will become payable on a quarterly basis commencing the first quarter of the following year, for the period of amortization based on the purpose of the draw. For Facilities C and D, each draw will become payable beginning the first full quarter post initial draw for the period of amortization based on the purpose of the draw. The amortization periods for Facilities B, C and D are based on the purposes of the draws as follows: draws for share repurchases are repaid over four years, draws for acquisitions over five years and draws for FTTH capital expenditures over seven years. The 2017 Amended Credit Facility also includes a mechanism that is triggered based on the Company's Total Funded Debt to EBITDA calculation at the end of each fiscal year. If Total Funded Debt to EBITDA exceeds 2.25:1 at December 31 of each year during the term, the Company is obligated to make a repayment of 50% of Excess Cash Flow as defined under the agreement.

The 2017 Amended Credit Facility contains customary representations and warranties, affirmative and negative covenants, and events of default. The 2017 Amended Credit Facility requires that the Company to comply with the following financial covenants at all times, which are to be calculated on a rolling four quarter basis: (i) maximum Total Funded Debt to EBITDA Ratio of 2.50:1 until September 30, 2018 and 2.25:1 thereafter; and (ii) minimum

Fixed Charge Coverage Ratio of 1.20:1. Further, the Company's maximum annual Capital Expenditures cannot exceed $50.0 million per year, which limit will be reviewed on an annual basis. In addition, funded share repurchases are not to exceed $20 million, or up to $40 million so long as the total loans related to share repurchases do not exceed 1.5 times of trailing twelve months EBITDA. As at and for the periods ending September 30, 2018, and September 30, 2017, the Company was in compliance with these covenants.

On January 24, 2018, the Company entered into the Second Interim Amendment to First Amended and Restated Credit Agreement (the "Second Interim Amendment") with BMO and the Lenders. The Second Interim Amendment provides that certain defined terms in Section 1.01 of the Credit Agreement are added and updated to reflect the inclusion of liabilities to Sprint Mobile similar to the previous inclusion of T-Mobile liabilities. The Second Interim Amendment also permits Tucows to retain bank accounts with Silicon Valley Bank with the aggregate amount held in such accounts not to exceed $3.0 million.

Borrowings under the 2017 Amended Credit Facility will accrue interest and standby fees based on the Company's Total Funded Debt to EBITDA ratio and the availment type as follows:

	If Total Funded Debt to EBITDA is:			
Availment type or fee	**Less than 1.00**	**Greater than or equal to 1.00 and less than 2.00**	**Greater than or equal to 2.00 and less than 2.25**	**Greater than or equal to 2.25**
Canadian dollar borrowings based on Bankers' Acceptance or U.S. dollar borrowings based on LIBOR (Margin)	2.00%	2.25 %	2.75 %	3.25 %
Canadian or U.S. dollar borrowings based on Prime Rate or U.S. dollar borrowings based on Base Rate (Margin)	0.75%	1.00 %	1.50 %	2.00 %
Standby fees	0.40%	0.45 %	0.55 %	0.65 %

Table of Contents

The following table summarizes the Company's borrowings under the credit facilities (Dollar amounts in thousands of U.S. dollars):

	September 30, 2018	December 31, 2017
Facility B	2,500	-
Facility C	3,393	5,930
Facility D	59,148	71,823
Less: unamortized debt discount and issuance costs	(626)	(829)
Total loan payable	64,415	76,924
Less: loan payable, current portion	17,810	18,290
Loan payable, long-term portion	46,605	58,634

The following table summarizes our scheduled principal repayments as of September 30, 2018 (Dollar amounts in thousands of U.S. dollars):

Remainder of 2018	4,386
2019	17,900
2020	17,900
2021	24,855
	$65,041

Other Credit Facilities

Prior to the Company entering into the 2016 Credit Facility, the Company had credit agreements (collectively the "Amended Credit Facility") with BMO that were amended on November 19, 2012, and which provided it with access to two revolving demand loan facilities, a treasury risk management facility, an operating demand loan and a credit card facility. The Company continues to have access to the treasury risk management facility and credit card facility, with the remaining loan facilities having been extinguished.

The treasury risk management facility under the Amended Credit Facility provides for a $3.5 million settlement risk line to assist the Company with hedging Canadian dollar exposure through foreign exchange forward contracts and/or currency options. Under the terms of the Amended Credit Facility, the Company may enter into such agreements at market rates with terms not to exceed 18 months. As of September 30, 2018, the Company held contracts in the amount of $10.7 million to trade U.S. dollars in exchange for Canadian dollars. See note 5 – Derivative instruments and hedging activities for more information.

In the fourth quarter of, 2017, the Company entered into a corporate credit card program with the Bank of Nova Scotia and the Lenders. The program provides that BMO and the Bank of Nova Scotia may establish corporate credit card facilities with the Company in an amount of up to $5 million, which was established in the fourth quarter of 2017.

8. Income taxes

For the three months ended September 30, 2018, we recorded an income tax expense of $1.4 million on income before income taxes of $6.7 million, using an estimated effective tax rate for the fiscal year ending December 31, 2018 ("Fiscal 2018") adjusted for certain minimum state taxes as well as the inclusion of a $0.2 million tax recovery related to ASU 2016-09, which requires all excess tax benefits and tax deficiencies related to employee share-based payments to be recognized through income tax expense. Comparatively, for the three months ended September 30, 2017, the Company recorded an income tax expense of $1.8 million on income before taxes of $5.3 million, using an estimated effective tax rate for the 2017 fiscal year and adjusted for the $0.4 million tax recovery impact related to ASU 2016-09.

Table of Contents

For the nine months ended September 30, 2018, we recorded an income tax expense of $3.8 million on income before income taxes of $16.5 million, using an estimated effective tax rate for Fiscal 2018 adjusted for certain minimum state taxes as well as the inclusion of a $0.5 million tax recovery related to ASU 2016-09, which requires all excess tax benefits and tax deficiencies related to employee share-based payments to be recognized through income tax expense. Comparatively, for the nine months ended September 30, 2017, the Company recorded income tax expense of $2.8 million on income before taxes of $13.9 million, using an estimated effective tax rate for the 2017 fiscal year and adjusted for the $2.6 million tax recovery impact related to ASU 2016-09.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the years in which those temporary differences become deductible. Management considers projected future taxable income, uncertainties related to the industry in which the Company operates, and tax planning strategies in making this assessment.

The Company recognizes accrued interest and penalties related to income taxes in income tax expense. The Company did not have significant interest and penalties accrued at September 30, 2018 and December 31, 2017, respectively.

9. Basic and diluted earnings per common share:

Basic earnings per common share has been calculated on the basis of net income for the period divided by the weighted average number of common shares outstanding during each year. Diluted earnings per share gives effect to all dilutive potential common shares outstanding at the end of the year assuming that they had been issued, converted or exercised at the later of the beginning of the year or their date of issuance. In computing diluted earnings per share, the treasury stock method is used to determine the number of shares assumed to be purchased from the conversion of common share equivalents or the proceeds of the exercise of options.

The following table reconciles the numerators and denominators of the basic and diluted earnings per common share computation (Dollar amounts in thousands of U.S. dollars, except per share amounts):

	Three months ended September 30,		**Nine months ended September 30,**	
	2018	**2017**	**2018**	**2017**
Numerator for basic and diluted earnings per common share:				

Net income for the period	$5,346	$3,440	$12,698	$11,128
Denominator for basic and diluted earnings per common share:				
Basic weighted average number of common shares outstanding	10,611,579	10,564,311	10,599,243	10,522,841
Effect of outstanding stock options	182,718	221,031	196,425	262,209
Diluted weighted average number of shares outstanding	10,794,297	10,785,342	10,795,668	10,785,050
Basic earnings per common share	$0.50	$0.33	$1.20	$1.06
Diluted earnings per common share	$0.50	$0.32	$1.18	$1.03

For the three months ended September 30, 2018, outstanding options to purchase 440,000 common shares were not included in the computation of diluted income per common share because all such options' exercise price was greater than the average market price of the common shares for the period as compared to the three months ended September 30, 2017, where 345,200 outstanding options were not included in the computation.

For the nine months ended September 30, 2018, outstanding options to purchase 440,000 common shares were not included in the computation of diluted income per common share because all such options' exercise price was greater than the average market price of the common shares for the period as compared to the nine months ended September 30, 2017, where 349,700 outstanding options were not included in the computation.

During the three and nine months ended September 30, 2018, the Company did not repurchase any shares under the stock buyback program commenced on February 14, 2018, which will be terminated on or before February 13, 2019.

During the three and nine months ended September 30, 2017 and the nine months ended September 30, 2018, the Company did not repurchase any shares under the stock buyback program commenced on March 1, 2017, which terminated on February 14, 2018.

During the nine months ended September 30, 2017, the company did not repurchase any shares under the stock buyback program commenced on February 10, 2016, which terminated on February 9, 2017.

Table of Contents

10. Revenue

Significant accounting policy

The Company’s revenues are derived from (a) the provisioning of mobile and fiber Internet services; and from (b) domain name registration contracts, other domain related value-added services, domain sale contracts, and other advertising revenue. Amounts received in advance of meeting the revenue recognition criteria described below are recorded as deferred revenue. All products are generally sold without the right of return or refund.

Revenue is measured based on consideration specified in a contract with a customer and excludes any sales incentives and amounts collected on behalf of third parties. The Company recognizes revenue when it satisfies a performance obligation by transferring control over a product or service to a customer.

Nature of goods and services

The following is a description of principal activities – separated by reportable segments – from which the Company generates its revenue. For more detailed information about reportable segments. See note 12 – Segment reporting for more information.

(a) Network Access Services

The Company generates Network Access Services revenues primarily through the provisioning of mobile services (“Ting Mobile”). Other sources of revenue include the provisioning of fixed high-speed Internet access (“Ting Internet”) as well as billing solutions to Internet Service Providers (“ISPs”).

Ting wireless usage contracts grant customers access to standard talk, text and data mobile services. Ting mobile contracts are billed based on the actual amount of monthly services utilized by each customer during their billing cycle and charged to customers on a postpaid basis. Voice minutes, text messages and megabytes of data are each billed separately based on a tiered pricing program. The Company recognizes revenue for Ting mobile usage based on the actual amount of monthly services utilized by each customer.

Ting Internet contracts provide customers Internet access at their home or business through the installation and use of our fiber optic network. Ting Internet contracts are generally prepaid and grant customers with unlimited bandwidth based on a fixed price per month basis. Because consideration is collected before the service period, revenue is initially deferred and recognized as the Company performs its obligation to provide Internet access. Though the Company does not consider the installation of fixed Internet access to be a distinct performance obligation, the fees related to installation are immaterial and therefore revenue is recognized as billed.

Both Ting Mobile and Ting Internet access services are primarily contracted through the Ting website, for one month at a time and contain no commitment to renew the contract following each customer's monthly billing cycle. The Company's billing cycle for all Ting Mobile and Ting Internet customers is computed based on the customer's activation date. In order to recognize revenue as the Company satisfies its obligations, we compute the amount of revenues earned but not billed from the end of each billing cycle to the end of each reporting period. In addition, revenues associated with the sale of wireless devices and accessories and Internet hardware to subscribers are recognized when title and risk of loss is transferred to the subscriber and shipment has occurred. Incentive marketing credits given to customers are recorded as a reduction of revenue.

Our Roam Mobility brand also offers standard talk, text and data mobile services. Roam customers prepay for their usage through the Roam Mobility website. When prepayments are received the amount is deferred, and subsequently recognized as the Company satisfies its obligation to provide mobile services. In addition, revenues associated with the sale of SIM cards are recognized when title and risk of loss is transferred to the subscriber and shipment has occurred. Incentive marketing credits given to customers are recorded as a reduction of revenue.

In those cases, where payment is not received at the time of sale, revenue is not recognized at contract inception unless the collection of the related accounts receivable is reasonably assured. The Company records costs that reflect expected refunds, rebates and credit card charge-backs as a reduction of revenues at the time of the sale based on historical experiences and current expectations.

(b) Domain Services

Domain registration contracts, which can be purchased for terms of one to ten years, provide our resellers and retail registrant customers with the exclusive right to a personalized internet address from which to build an online presence. The Company enters into domain registration contracts in connection with each new, renewed and transferred-in domain registration. At the inception of the contract, the Company charges and collects the registration fee for the entire registration period. Though fees are collected upfront, revenue from domain registrations are recognized ratably over the registration period as domain registration contracts contain a 'right to access' license of IP, which is a distinct performance obligation measured over time. The registration period begins once the Company has confirmed that the requested domain name has been appropriately recorded in the registry under contractual performance standards.

Table of Contents

Domain related value-added services like digital certifications, WHOIS privacy and hosted email provide our resellers and retail registrant customers tools and additional functionality to be used in conjunction with domain registrations. All domain related value-added services are considered distinct performance obligations which transfer the promised service to the customer over the contracted term. Fees charged to customers for domain related value-added services are collected at the inception of the contract, and revenue is recognized on a straight-line basis over the contracted term, consistent with the satisfaction of the performance obligations.

The Company is an ICANN accredited registrar. Thus, the Company is the primary obligor with our reseller and retail registrant customers and is responsible for the fulfillment of our registrar services to those parties. As a result, the Company reports revenue in the amount of the fees we receive directly from our reseller and retail registrant customers. Our reseller customers maintain the primary obligor relationship with their retail customers, establish pricing and retain credit risk to those customers. Accordingly, the Company does not recognize any revenue related to transactions between our reseller customers and their ultimate retail customers.

The Company also sells the rights to the Company’s portfolio domains or names acquired through the Company’s domain expiry stream. Revenue generated from sale of domain name contracts, containing a distinct performance obligation to transfer the domain name rights under the Company’s control, is generally recognized once the rights have been transferred and payment has been received in full.

Advertising revenue is derived through domain parking monetization, whereby the Company contracts with third-party Internet advertising publishers to direct web traffic from the Company’s domain expiry stream domains and Internet portfolio domains to advertising websites. Compensation from Internet advertising publishers is calculated variably on a cost-per-action basis based on the number of advertising links that have been visited in a given month. Given that the variable consideration is calculated and paid on a monthly basis, no estimation of variable consideration is required.

Disaggregation of Revenue

The following is a summary of the Company’s revenue earned from each significant revenue stream (Dollar amounts in thousands of U.S. dollars):

	Three months ended September 30,		**Nine months ended September 30,**	
	2018	**2017***	**2018**	**2017***

Network Access Services:				
Mobile Services	$22,546	$21,749	$66,829	$60,090
Other Services	2,033	1,442	5,664	3,978
Total Network Access Services	24,579	23,191	72,493	64,068
Domain Services:				
Wholesale				
Domain Services	45,070	47,770	146,038	135,413
Value Added Services	4,541	4,203	13,576	13,526
Total Wholesale	49,611	51,973	159,614	148,939
Retail	8,731	8,873	25,644	22,937
Portfolio	598	971	2,650	2,856
Total Domain Services	58,940	61,817	187,908	174,732
	$83,519	$85,008	$260,401	$238,800

During the three and nine months ended September 30, 2018, no customer accounted for more than 10% of total revenue. During the three and nine months ended September 30, 2017, no customer accounted for more than 10% of revenue. As at September 30, 2018 and December 31, 2017, no customer accounted for more than 10% of accounts receivable.

Table of Contents

The following is a summary of the Company's cost of revenue from each significant revenue stream (Dollar amounts in thousands of U.S. dollars):

	Three months ended September 30,		**Nine months ended September 30,**	
	2018	**2017***	**2018**	**2017***
Network Access Services:				
Mobile Services	$11,399	$12,365	$34,643	$32,634
Other Services	872	595	3,103	2,366
Total Network Access Services	12,271	12,960	37,746	35,000
Domain Services:				
Wholesale				
Domain Services	37,414	42,293	124,572	119,207
Value Added Services	807	687	2,412	1,878
Total Wholesale	38,221	42,980	126,984	121,085
Retail	4,465	4,611	13,320	12,776
Portfolio	148	180	528	627
Total Domain Services	42,834	47,771	140,832	134,488
Network Expenses:				
Network, other costs	2,315	2,461	7,590	7,064
Network, depreciation and amortization costs	1,838	1,322	5,195	3,463
	4,153	3,783	12,785	10,527
	$59,258	$64,514	$191,363	$180,015

Contract Balances

The following table provides information about contract liabilities (deferred revenue) from contracts with customers. The Company accounts for contract assets and liabilities on a contract-by-contract basis, with each contract presented as either a net contract asset or a net contract liability accordingly.

Given that Company's long-term contracts with customers are billed in advance of service, the Company's contract liabilities relate to amounts recorded as deferred revenues. The Company does not have material streams of contracted revenue that have not been billed.

Deferred revenue primarily relates to the portion of the transaction price received in advance related to the unexpired term of domain name registrations and other domain related value-added services, on both a wholesale and retail basis, net of external commissions.

The opening balance of deferred revenue was $160.6 million as of January 1, 2018. Significant changes in deferred revenue were as follows (Dollar amounts in thousands of U.S. dollars):

	Three months ended September 30, 2018	**Nine months ended September 30, 2018**
Balance, beginning of period	$ 152,052	$ 160,582
Deferred revenue	54,181	170,904
Recognized revenue [1]	(57,741)	(182,994)
Balance, end of period	$ 148,492	$ 148,492

[1]As a result of the bulk transfers of 2.65 million domain names to Namecheap on January 5, 2018 and 0.24 million domain names to Namecheap on September 25, 2018, recognized revenue for the three and nine months ended September 30, 2018 includes $1.7 million and $16.3 million, respectively, related to previously deferred revenue, a portion of which would have otherwise been recognized after September 30, 2018.

Remaining Performance Obligations:

As the Company fulfills its performance obligations, the following table includes revenues expected to be recognized in the future related performance obligations that are unsatisfied (or partially unsatisfied) as at September 30, 2018 (Dollar amounts in thousands of U.S. dollars):

For mobile and internet access services, where the performance obligation is part of contracts that have an original expected duration of one year or less (typically one month), the Company has elected to apply a practical expedient to not disclose revenues expected to be recognized in the future related performance obligations that are unsatisfied (or partially unsatisfied) (Dollar amounts in thousands of US dollars).

Table of Contents

	September 30, 2018
Remainder of 2018	$ 48,701
2019	76,153
2020	10,331
2021	5,040
2022	3,244
Thereafter	4,760
Total	$ 148,229

11. Contract Costs

(a) Deferred costs of acquisition

We recognize an asset for the incremental costs of obtaining a contract with a customer if we expect the period of benefit of those costs to be longer than one year and those costs are expected to be recoverable under the term of the contract. We have identified certain sales incentive programs that meet the requirements to be capitalized, and therefore, capitalized them as contract costs in the amount of $1.4 million at September 30, 2018.

Capitalized contract acquisition costs are amortized into operating expense based on the transfer of goods or services to which the assets relate which typically range 2 – 10 years. For the three months ended September 30, 2018, the Company capitalized $0.2 million and also amortized $0.2 million of contract costs, respectively. For the nine months ended September 30, 2018, the Company capitalized $0.7 million and also amortized $0.7 million of contract costs, respectively. There was no impairment loss recognized in relation to the costs capitalized during the three or nine months ending September 30, 2018. The breakdown of the movement in the contract costs balance for the three and nine months ending September 30, 2018 is as follows (Dollar amounts in thousands of U.S. dollars):

	Three months ended September 30, 2018	**Nine months ended September 30, 2018 (1)**

Balance, beginning of period	$ 1,354	$ 1,404
Deferral of costs	245	684
Recognized costs	(216)	(705)
Balance, end of period	$ 1,383	$ 1,383

(1)The beginning balance consists entirely of a cumulative adjustment recorded on January 1, 2018 as a result of the modified retrospective adoption of ASU 2014-09. See note 3 – Recent accounting pronouncements for more information.

When the amortization period for costs incurred to obtain a contract with a customer is less than one year, we have elected to apply a practical expedient to expense the costs as incurred. These costs include our internal sales compensation program and certain partner sales incentive programs.

Table of Contents

(b) Deferred costs of fulfillment

Deferred costs to fulfill contracts generally consist of domain registration costs which have been paid to a domain registry, and are capitalized as Prepaid domain name registry and ancillary services fees. These costs are deferred and amortized over the life of the domain which generally ranges from one to ten years. For the three months ended September 30, 2018, the Company capitalized $39.5 million and also amortized $43.7 million of contract costs, respectively. For the nine months ended September 30, 2018, the Company capitalized $126.6 million and also amortized $142.4 million of contract costs, respectively. There was no impairment loss recognized in relation to the costs capitalized during the three or nine months ending September 30, 2018. Amortization expense is primarily included in cost of revenue. The breakdown of the movement in the prepaid domain name registry and ancillary services fees balance for the three and nine months ended September 30, 2018 is as follows (Dollar amounts in thousands of U.S. dollars).

	Three months ended September 30, 2018	**Nine months ended September 30, 2018**
Balance, beginning of period	$ 115,456	$ 127,003
Deferral of costs	39,453	126,613
Recognized costs [1]	(43,683)	(142,390)
Balance, end of period	$ 111,226	$ 111,226

[1]As a result of the bulk transfers of 2.65 million domain names to Namecheap on January 5, 2018 and 0.24 million domain names to Namecheap on September 25, 2018, recognized revenue for the three and nine months ended September 30, 2018 includes $1.7 million and $16.2 million, respectively, related to previously deferred revenue, a portion of which would have otherwise been recognized after September 30, 2018.

12. Segment reporting:

(a) We are organized and managed based on two operating segments which are differentiated primarily by their services, the markets they serve and the regulatory environments in which they operate and are described as follows:

1. Network Access Services - This segment derives revenue from the sale of mobile phones, telephony services, high speed Internet access, billing solutions to individuals and small businesses primarily through the Ting website. Revenues are generated in the U.S.

2. Domain Services – This segment includes wholesale and retail domain name registration services, value added services and portfolio services. The Company primarily earns revenues from the registration fees charged to resellers in connection with new, renewed and transferred domain name registrations; the sale of retail Internet domain name registration and email services to individuals and small businesses; and by making its portfolio of domain names available for sale or lease. Domain Services revenues are attributed to the country in which the contract originates, primarily Canada and the U.S.

The Chief Executive Officer (the "CEO") is the chief operating decision maker and regularly reviews the operations and performance by segment. The CEO reviews gross profit as (a) key measure of performance for each segment and (b) to make decisions about the allocation of resources. Sales and marketing expenses, technical operations and development expenses, general and administrative expenses, depreciation of property and equipment, amortization of intangibles assets, impairment of indefinite life intangible assets, gain on currency forward contracts and other expense net are organized along functional lines and are not included in the measurement of segment profitability. Total assets and total liabilities are centrally managed and are not reviewed at the segment level by the CEO. The Company follows the same accounting policies for the segments as those described in notes 2 – Basis of presentation, 3 – Recent accounting pronouncements, and 10 - Revenue.

Table of Contents

Information by operating segments (with the exception of disaggregated revenue, which is discussed in note 10 - Revenue), which is regularly reported to the CEO is as follows (Dollar amounts in thousands of U.S. dollars):

Three months ended September 30, 2018	Network Access Services	Domain Services	Consolidated Totals
Net Revenues	$ 24,579	$ 58,940	$ 83,519
Cost of revenues			
Cost of revenues	12,271	42,834	55,105
Network expenses	479	1,836	2,315
Depreciation of property and equipment	1,026	313	1,339
Amortization of intangible assets	11	488	499
Total cost of revenues	13,787	45,471	59,258
Gross Profit	10,792	13,469	24,261
Expenses:			
Sales and marketing			8,412
Technical operations and development			2,207
General and administrative			

Commodity

Instrument

Classification

Unit of
Measure

Cash Flow
Hedges

Economic
Hedges

Trading
Activities

Electricity

Forwards/Futures

Sales, net

GWh

5,850

1
102

3
—

Electricity

Forwards/Futures

Purchases, net

GWh

—

—

2,425

Electricity

Capacity

Sales, net

MW-Day
(in thousands)

58

2
—

—

Electricity

Capacity

Purchases, net

MW-Day
(in thousands)

—

—

161

2
Electricity

Congestion

Purchases, net

GWh

—

1,079

4
165,365

4
Natural gas

Forwards/Futures

Purchases, net

bcf

—

—

12.0

Fuel oil

Forwards/Futures

Purchases, net

barrels

—

360,000

—

At March 31, 2012, EMG had interest rate contracts with notional values totaling $681 million that converted floating rate LIBOR-based debt to fixed rates ranging from 0.79% to 4.29%. These contracts expire May 2013 through March 2026. In addition, at March 31, 2012, EME had forward starting interest rate contracts with notional values totaling $502 million that will convert floating rate LIBOR-based debt to fixed rates ranging from 3.5429% to 4.0025%. These contracts have effective dates beginning June 2013 through December 2021 and expire May 2023 through December 2029.

In April 2012 pursuant to the agreements for financing of its interests in the Broken Bow and Crofton Bluffs wind projects, EME's subsidiaries entered into forward starting interest rate swap agreements with notional value totaling $139 million that converted floating rate LIBOR based debt to fixed rates ranging from 0.7825% to 2.96%. These contracts have effective dates beginning December 2012 through December 2013 and expire December 2013 through December 2027.

21

December 31, 2011

Commodity	Instrument	Classification	Unit of Measure	Hedging Activities: Cash Flow Hedges	Hedging Activities: Economic Hedges	Trading Activities
Electricity	Forwards/Futures	Sales, net	GWh	8,320 [1]	425 [3]	—
Electricity	Forwards/Futures	Purchases, net	GWh	—	—	2,926
Electricity	Capacity	Sales, net	MW-Day (in thousands)	89 [2]	—	—
Electricity	Capacity	Purchases, net	MW-Day (in thousands)	—	—	184 [2]
Electricity	Congestion	Purchases, net	GWh	—	2,528 [4]	230,798 [4]
Natural gas	Forwards/Futures	Sales, net	bcf	—	—	0.2
Fuel oil	Forwards/Futures	Purchases, net	barrels	—	240,000	—

[1] EMG's hedge products include forward and futures contracts that qualify for hedge accounting.

[2] EMG's hedge transactions for capacity result from bilateral trades. Capacity sold in the PJM Interconnection, LLC Reliability Pricing Model (PJM RPM) auction is not accounted for as a derivative.

[3] These positions adjust financial and physical positions, or day-ahead and real-time positions, to reduce costs or increase gross margin. The net sales positions of these categories are primarily related to hedge transactions that are not designated as cash flow hedges.

[4] Congestion contracts include financial transmission rights, transmission congestion contracts or congestion revenue rights. These positions are similar to a swap, where the buyer is entitled to receive a stream of revenues (or charges) based on the hourly day-ahead price differences between two locations.

At December 31, 2011, EMG had interest rate contracts with notional values totaling $644 million that converted floating rate LIBOR-based debt to fixed rates ranging from 0.79% to 4.29%. These contracts expire May 2013 through March 2026. In addition, EMG had forward starting interest rate contracts with notional values totaling $506 million that will convert floating
rate LIBOR-based debt to fixed rates of 3.5429%, 3.57% and 4.0025%. These contracts have effective dates of June 2013 and December 2021 and expire May 2023 and December 2029.

Fair Value of Derivative Instruments

The following table summarizes the fair value of derivative instruments reflected on EMG's consolidated balance sheets:

March 31, 2012

(in millions)	Derivative Assets: Short-term	Long-term	Subtotal	Derivative Liabilities: Short-term	Long-term	Subtotal	Net Assets (Liabilities)
Non-trading activities							
Cash flow hedges							
Commodity contracts	$51	$2	$53	$1	$3	$4	$49
Interest rate contracts	—	—	—	—	78	78	(78)
Economic hedges	57	3	60	47	2	49	11
Trading activities	408	180	588	360	117	477	111
	516	185	701	408	200	608	93
Netting and collateral received[1]	(477)	(133)	(610)	(407)	(121)	(528)	(82)
Total	$39	$52	$91	$1	$79	$80	$11

22

December 31, 2011

	Derivative Assets			Derivative Liabilities			
(in millions)	Short-term	Long-term	Subtotal	Short-term	Long-term	Subtotal	Net Assets (Liabilities)
Non-trading activities							
Cash flow hedges							
Commodity contracts	$41	$1	$42	$2	$3	$5	$37
Interest rate contracts	—	—	—	—	90	90	(90)
Economic hedges	31	1	32	26	1	27	5
Trading activities	276	142	418	232	79	311	107
	348	144	492	260	173	433	59
Netting and collateral received[1]	(308)	(85)	(393)	(259)	(83)	(342)	(51)
Total	$40	$59	$99	$1	$90	$91	$8

1 Netting of derivative receivables and derivative payables and the related cash collateral received and paid is permitted when a legally enforceable master netting agreement exists with a derivative counterparty.

Income Statement Impact of Derivative Instruments

The following table provides the cash flow hedge activity as part of accumulated other comprehensive loss:

	Cash Flow Hedge Activity[1] Three Months Ended March 31,				
	2012		2011		
(in millions)	Commodity Contracts	Interest Rate Contracts	Commodity Contracts	Interest Rate Contracts	Income Statement Location
Beginning of period derivative gains (losses)	$35	$(90)	$43	$(16)	
Effective portion of changes in fair value	30	12	8	2	
Reclassification to earnings	(19)	—	(16)	—	Competitive power generation revenue
End of period derivative gains (losses)	$46	$(78)	$35	$(14)	

1 Unrealized derivative gains (losses) are before income taxes. The after-tax amounts recorded in accumulated other comprehensive loss at March 31, 2012 and 2011 for commodity and interest rate contracts were $27 million and $(47) million, and $21 million and $(9) million, respectively.

For additional information, see Note 11.

EMG recorded net gains of $1 million and $2 million during the first quarters of 2012 and 2011, respectively, in operating revenues on the consolidated statements of operations representing the amount of cash flow hedge ineffectiveness.

The effect of realized and unrealized gains from derivative instruments used for economic hedging and trading purposes on the consolidated statements of operations is presented below:

		Three Months Ended March 31,	
(in millions)	Income Statement Location	2012	2011
Economic hedges	Competitive power generation revenue	$11	$6
	Fuel	5	6
Trading activities	Competitive power generation revenue	20	16

23

Contingent Features

Certain derivative instruments contain margin and collateral deposit requirements. Since EME's and its subsidiaries' credit ratings are below investment grade, EME and its subsidiaries have provided collateral in the form of cash and letters of credit for the benefit of derivative counterparties.

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers, and cash received from counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the fair value of the related positions. Edison International nets counterparty receivables and payables where balances exist under master netting agreements. Edison International presents the portion of its margin and collateral deposits netted with its derivative positions on its consolidated balance sheets. The following table summarizes margin and collateral deposits provided to and received from counterparties:

(in millions)	March 31, 2012	December 31, 2011
Collateral provided to counterparties:		
Offset against derivative liabilities	$ 83	$ 53
Reflected in margin and collateral deposits	96	58
Collateral received from counterparties:		
Offset against derivative assets	84	53

Note 7. Income Taxes

Effective Tax Rate

The table below provides a reconciliation of income tax expense computed at the federal statutory income tax rate to the income tax provision.

	Three months ended March 31,	
(in millions)	2012	2011
Income from continuing operations before income taxes	$ 115	$ 281
Provision for income tax at federal statutory rate of 35%	40	98
Increase (decrease) in income tax from:		
State tax benefit – net of federal tax expense	(9)	—
Production and housing credits	(19)	(18)
Property-related	(10)	(11)
Other	(2)	(4)
Total income tax expense from continuing operations	$—	$ 65
Effective tax rate	*	23 %

* Not meaningful

The CPUC requires flow-through ratemaking treatment for the current tax benefit arising from certain property-related and other temporary differences which reverse over time. The accounting treatment for these temporary differences results in recording regulatory assets and liabilities for amounts that would otherwise be recorded to deferred income tax expense.

Tax Dispute

Edison International's federal income tax returns and its California combined franchise tax returns are currently open for years subsequent to 2002. In addition, specific California refund claims made by Edison International for years 1991 through
2002 are currently under review by the Franchise Tax Board. The IRS examination phase of tax years 2003 through 2006 was completed in the fourth quarter of 2010, which included proposed adjustments for the following two items:

- A proposed adjustment increasing the taxable gain on the 2004 sale of EMG's international assets, which if sustained, would result in a federal tax payment of approximately $194 million, including interest and penalties through March 31, 2012 (the IRS has asserted a 40% penalty for understatement of tax liability related to this matter).
- A proposed adjustment to disallow a component of SCE's repair allowance deduction, which if sustained, would result in a federal tax payment of approximately $94 million, including interest through March 31, 2012.

Edison International disagrees with the proposed adjustments and filed a protest with the IRS in the first quarter of 2011. Federal income taxes of Edison International and its consolidated subsidiaries are generally the joint and several liabilities of members of the group under applicable tax laws and are paid by Edison International as the group's consolidated taxpayer, subject to internal tax-allocation agreements.

Tax Election at Homer City

On March 15, 2012, Homer City LP filed an election with the Internal Revenue Service to be treated as a partnership for federal and state income tax purposes effective for tax year 2011. As a result of this election, Homer City LP was treated for income tax purposes as though it had distributed all of its assets and liabilities to its partners, both of which are wholly-owned subsidiaries of EME. This distribution triggered a tax deduction of approximately $1.0 billion, which will be included on Edison International's 2011 federal and state income tax returns.

Loss and Credit Carryforwards

Including the tax deduction generated from the Homer City election, Edison International has recorded tax benefits for federal and state net operating loss carryforwards and federal tax credit carryforwards of approximately $1.2 billion as of March 31, 2012.

Note 8. Pension Plans and Postretirement Benefits Other Than Pensions

Pension Plans

Edison International made contributions of $7 million during the three months ended March 31, 2012 and expects to make $279 million of additional contributions during the remainder of 2012. In 2012, annual contributions made to most of the pension plans for SCE employees are anticipated to be recovered through CPUC-approved regulatory mechanisms, pending outcome of the 2012 GRC decision. Annual contributions to these plans are expected to be, at a minimum, equal to the related annual expense.

Expense components are:

	Three months ended March 31,	
(in millions)	2012	2011
Service cost	$43	$43
Interest cost	49	52
Expected return on plan assets	(59)	(60)
Amortization of prior service cost	1	2
Amortization of net loss	18	6
Expense under accounting standards	52	43
Regulatory adjustment (deferred)	25	(6)
Total expense recognized	$77	$37

25

Postretirement Benefits Other Than Pensions

Edison International made contributions of $6 million during the three months ended March 31, 2012 and expects to make $59 million of additional contributions during the remainder of 2012. In 2012, annual contributions made to plans for SCE employees are anticipated to be recovered through CPUC-approved regulatory mechanisms, pending outcome of the 2012 GRC decision. Annual contributions are expected to be, at a minimum, equal to the total annual expense for these plans. Benefits under these plans, with some exceptions, are generally unvested and subject to change.

Expense components are:

	Three months ended March 31,	
(in millions)	2012	2011
Service cost	$ 13	$ 11
Interest cost	30	33
Expected return on plan assets	(27)	(28)
Amortization of prior service credit	(9)	(9)
Amortization of net loss	12	9
Total expense	$ 19	$ 16

Note 9. Commitments and Contingencies

Power Plant and Other Lease Commitments

Homer City Lease and Environmental Project

Homer City made the required April 1, 2012 senior rent payment but did not make the April 1, 2012 payment of equity rent. On March 30, 2012, Homer City was granted a waiver by the owner-lessors of any rent default event with respect to the payment of the equity rent for all purposes other than restrictions on distributions from Homer City, including repayment of its intercompany loan, and the $48 million senior rent reserve letter of credit remains in place. For further discussion of the Homer City lease, refer to "Item 8. Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies—Power Plant and Other Lease Commitments—Sale-Leaseback Transactions" in the 2011 Form 10-K.

On March 29, 2012, Homer City and General Electric Capital Corporation ("GECC") entered into an Implementation Agreement (the Agreement) with respect to the Homer City plant. As addressed by the Agreement, an affiliate of the GECC-controlled owner-lessors of the Homer City plant has entered into an engineering, procurement and construction agreement and is in the process of executing related agreements for the construction of environmental improvements. GECC will have discretion over all decisions related to such agreements. Homer City agreed to conduct its business as set forth in the Agreement and to use commercially reasonable efforts to provide assistance to GECC and its affiliates in connection with the construction agreements. The Agreement also requires Homer City, at the request of GECC, to enter into one or more implementation transactions, as defined in the Agreement, for the divestiture of its leasehold interest in the Homer City plant (and, under certain circumstances, related assets and liabilities as specified) and to assist GECC in obtaining certain third-party consents or waivers. Homer City and GECC also agreed to enter into a transition services agreement in connection with any implementation transaction. There is no assurance that Homer City and GECC will actually consummate a divestiture transaction as contemplated by the Agreement.

The Agreement also contains certain indemnities by each party in favor of the other. The Agreement may be terminated by GECC in its sole discretion at any time effective immediately upon delivery of notice to Homer City. Homer City may terminate the Agreement in connection with certain terminations of the construction agreements, subject to certain conditions.

The estimated cost of installing sulfur dioxide ("SO_2") and particulate emissions control equipment for Units 1 and 2 of the Homer City plant is expected to be approximately $700 million to $750 million. On April 2, 2012, Homer City received the permit to construct such improvements from the Pennsylvania Department of Environmental Protection ("PADEP").

Included in the consolidated balance sheet at March 31, 2012 are assets and liabilities of Homer City. In the event that Homer City completes a divestiture transaction with its owner-lessors or EME ceases to control Homer City, EME will record a loss on disposition and classify Homer City as a discontinued operation. At March 31, 2012, Homer City assets of $209 million were composed of cash, inventory, and other assets and liabilities of $84 million were composed of accounts payable, accrued

26

liabilities and other liabilities. In addition, EMMT had an intercompany account receivable from Homer City of $13 million at March 31, 2012. Any loss on disposition will be determined based on the assets and liabilities as of the date of disposition, the terms and conditions of the relevant transaction and an assessment as to whether any ongoing contingencies exist.

Guarantees and Indemnities

Edison International's subsidiaries have various financial and performance guarantees and indemnity agreements which are issued in the normal course of business. The contracts discussed below included performance guarantees.

Environmental Indemnities Related to the Midwest Generation Plants

In connection with the acquisition of the Midwest Generation plants, EME agreed to indemnify Commonwealth Edison Company (Commonwealth Edison) with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification obligations are reduced by any insurance proceeds and tax benefits related to such indemnified claims and are subject to a requirement that Commonwealth Edison takes all reasonable steps to mitigate losses related to any such indemnification claim. Also, in connection with the sale-leaseback transaction related to the Powerton and Joliet Stations in Illinois, EME agreed to indemnify the owner-lessors for specified environmental liabilities. These indemnities are not limited in term or amount. Due to the nature of the obligations under these indemnities, a maximum potential liability cannot be determined. Commonwealth Edison has advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the litigation discussed below under "—Contingencies—Midwest Generation New Source Review and Other Litigation." Except as discussed below, EME has not recorded a liability related to these environmental indemnities.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation Company LLC on February 20, 2003 to resolve a dispute regarding interpretation of Midwest Generation's reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Asset Sale Agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic renewal provision, it has been extended until February 2013. There were approximately 245 cases for which Midwest Generation was potentially liable that had not been settled and dismissed at March 31, 2012. Midwest Generation had recorded a liability of $54 million at March 31, 2012 related to this contractual indemnity.

Indemnities Related to the Homer City Plant

In connection with the acquisition of the Homer City plant, Homer City agreed to indemnify the sellers with respect to specified environmental liabilities before and after the date of sale. EME guaranteed this obligation of Homer City. Also, in connection with the sale-leaseback transaction related to the Homer City plant, Homer City agreed to indemnify the owner-lessors for specified environmental liabilities. Due to the nature of the obligations under these indemnity provisions, they are not subject to a maximum potential liability and do not have expiration dates. EME has not recorded a liability related to this indemnity. For discussion of the New Source Review lawsuit filed against Homer City, see "—Contingencies—Homer City New Source Review and Other Litigation." Also, in connection with the Implementation Agreement discussed above, Homer City has agreed to enter into one or more implementation transactions, at the request of GECC, on the terms outlined in the Implementation Agreement, which include indemnification for specified matters.

Indemnities Provided under Asset Sale and Sale-Leaseback Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. At March 31, 2012, EME had recorded a liability of $34 million related to these matters.

In connection with the sale-leaseback transactions related to the Homer City plant in Pennsylvania, the Powerton and Joliet Stations in Illinois and, previously, the Collins Station in Illinois, EME and several of its subsidiaries entered into tax indemnity agreements. Under certain of these tax indemnity agreements, Homer City and Midwest Generation, as the lessees in the sale-leaseback transactions agreed to indemnify the respective owner-lessors for specified adverse tax consequences that could result from certain situations set forth in each tax indemnity agreement, including specified defaults under the respective leases. Although the Collins Station lease terminated in April 2004, Midwest Generation's indemnities in favor of its former lease equity investors are still in effect. EME provided similar indemnities in the sale-leaseback transactions related to the Powerton and Joliet Stations in Illinois. The potential indemnity obligations under these tax indemnity agreements could be significant. Due to the nature of these potential obligations, EME cannot determine a range of estimated obligation which would be triggered by a valid claim from the owner-lessors. EME has not recorded a liability for these matters.

In addition to the indemnity provided by Homer City, EME agreed to indemnify the owner-lessors in the sale-leaseback transaction related to the Homer City plant for certain negative federal income tax consequences should the rent payments be "levelized" for tax purposes and for potential foreign tax credit losses in the event that the owner-lessor's debt is characterized as recourse, rather than nonrecourse. This indemnity covers a limited range of possible tax consequences that are unrelated to performance under the lease.

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of the Mountainview power plant, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

Mountainview Filter Cake Indemnity

SCE has indemnified the City of Redlands, California in connection with Mountainview's California Energy Commission permit for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this indemnity.

Other Edison International Indemnities

Edison International provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and indemnities for specified environmental liabilities and income taxes with respect to assets sold. Edison International's obligations under these agreements may or may not be limited in terms of time and/or amount, and in some instances Edison International may have recourse against third parties. Edison International has not recorded a liability related to these indemnities. The overall maximum amount of the obligations under these indemnifications cannot be reasonably estimated.

Contingencies

In addition to the matters disclosed in these Notes, Edison International is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. Edison International believes the outcome of these other proceedings, individually and in the aggregate, will not materially affect its results of operations or liquidity.

Midwest Generation New Source Review and Other Litigation

In August 2009, the United States Environmental Protection Agency ("US EPA") and the State of Illinois filed a complaint in the Northern District of Illinois alleging that Midwest Generation or Commonwealth Edison performed repair or replacement projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration (PSD) requirements and of the New Source Performance Standards of the Clean Air Act (CAA), including alleged requirements to obtain a construction permit and to install controls sufficient to meet best available control technology (BACT) emission rates. The US EPA also alleged that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the CAA. Finally, the US EPA alleged violations of certain opacity and particulate matter standards at the Midwest Generation plants. In addition to seeking penalties ranging from $25,000 to $37,500 per violation, per day, the complaint called for an injunction ordering Midwest Generation to install controls sufficient to meet BACT emission rates at all units subject to the complaint and other remedies. The remedies sought by the plaintiffs in the lawsuit could go well beyond the requirements of the Combined Pollutant Standard (CPS). Several Chicago-based environmental action groups intervened in the case.

Nine of the ten PSD claims raised in the complaint have been dismissed, along with claims related to alleged violations of Title V of the CAA, to the extent based on the dismissed PSD claims, and all claims asserted against Commonwealth Edison and EME. The court denied a motion to dismiss a claim by the Chicago-based environmental action groups for civil penalties in the remaining PSD claim, but noted that the plaintiffs will be required to convince the court that the statute of limitations should be equitably tolled. The court did not address other counts in the complaint that allege violations of opacity and particulate matter limitations under the Illinois State Implementation Plan and Title V of the CAA. The dismissals have been certified as "partial final judgments" capable of appeal, and an appeal is pending before the Seventh Circuit Court of Appeals. The remaining claims have been stayed pending the appeal. In February 2012, certain of the environmental action groups that had intervened in the case entered into an agreement with Midwest Generation to dismiss without prejudice all of their opacity claims as to all defendants. The agreed upon motion to dismiss was approved by the court on March 26, 2012.

In January 2012, two complaints were filed against Midwest Generation in Illinois state court by residents living near the Crawford and Fisk Stations on behalf of themselves and all others similarly situated, each asserting claims of nuisance, negligence, trespass, and strict liability. The plaintiffs seek to have their suits certified as a class action and request injunctive relief, as well as compensatory and punitive damages. The complaints are similar to two complaints previously filed in the Northern District of Illinois, which were dismissed in October 2011 for lack of federal jurisdiction. In March 2012, Midwest Generation filed motions to dismiss the cases, which are pending.

Adverse decisions in these cases could involve penalties, remedial actions and damages that could have a material impact on the financial condition and results of operations of Midwest Generation and EME. EME cannot predict the outcome of these matters or estimate the impact on the Midwest Generation plants, or its and Midwest Generation's results of operations, financial position or cash flows. EME has not recorded a liability for these matters.

Homer City New Source Review and Other Litigation

In January 2011, the US EPA filed a complaint in the Western District of Pennsylvania against Homer City, the sale-leaseback owner participants of the Homer City plant, and two prior owners of the Homer City plant. The complaint alleged violations of the PSD and Title V provisions of the CAA, as a result of projects in the 1990s performed by prior owners without PSD permits and the subsequent failure to incorporate emissions limitations that meet BACT into the station's Title V operating permit. In addition to seeking penalties ranging from $32,500 to $37,500 per violation, per day, the complaint called for an injunction ordering Homer City to install controls sufficient to meet BACT emission rates at all units subject to the complaint and for other remedies. The PADEP, the State of New York and the State of New Jersey intervened in the lawsuit. In October 2011, all of the claims in the US EPA's lawsuit were dismissed with prejudice. An appeal of the dismissal is pending before the Third Circuit Court of Appeals.

Also in January 2011, two residents filed a complaint in the Western District of Pennsylvania, on behalf of themselves and all others similarly situated, against Homer City, the sale-leaseback owner participants of the Homer City plant, two prior owners of the Homer City plant, EME, and Edison International, claiming that emissions from the Homer City plant had adversely affected their health and property values. The plaintiffs sought to have their suit certified as a class action and requested injunctive relief, the funding of a health assessment study and medical monitoring, as well as compensatory and punitive damages. In October 2011, the claims in the purported class action lawsuit that were based on the federal CAA were dismissed with prejudice, while state law statutory and common law claims were dismissed without prejudice to re-file in state court should the plaintiffs choose to do so. EME does not know whether the plaintiffs will file a complaint in state court.

In February 2012, Homer City received a 60-day Notice of Intent to Sue indicating the Sierra Club's intent to file a citizen lawsuit alleging violations of emissions standards and limitations under the CAA and the Pennsylvania Air Pollution Control Act.

Adverse decisions in these cases could involve penalties, remedial actions and damages that could have a material impact on the financial condition and results of operations of Homer City and EME. EME cannot predict the outcome of these matters or estimate the impact on the Homer City plant, or its and Homer City's results of operations, financial position or cash flows. EME has not recorded a liability for these matters.

CPSD Investigations

San Gabriel Valley Windstorm Investigation

In November 2011, a windstorm resulted in significant damage to SCE's electric system and service outages for SCE customers primarily in the San Gabriel Valley. The CPUC directed its Consumer Protection and Safety Division

(“CPSD”) to conduct an investigation focused on the cause of the outages, SCE’s service restoration effort, and SCE’s customer communications during the outages. The CPSD issued its preliminary report on February 1, 2012. The report asserts that SCE and others with whom SCE shares utility poles violated certain CPUC safety rules applicable to overhead line construction, maintenance and operation, which may have caused the failures of affected poles and supporting cables. The report also concludes that SCE’s restoration time was not adequate and makes other assertions. Additionally, the report contends that

SCE violated CPUC rules by failing to preserve evidence relevant to the investigation when it did not retain damaged poles that were replaced following the windstorm. If the CPUC issues an Order Instituting Investigation ("OII") regarding this matter and SCE is found to have violated any CPUC rules, it could face penalties. In addition, the cost of any large scale review of poles or other equipment for safety compliance could be significant. SCE is unable to estimate a possible loss or range of loss associated with any penalties that may be imposed by the CPUC on SCE.

Malibu Fire Order Instituting Investigation

Following a 2007 wildfire in Malibu, California, the CPUC issued an OII to determine if any statutes, CPUC general orders, rules or regulations were violated by SCE or telecomm providers (“OII Respondents”) that shared the use of three failed power poles in the wildfire area. The CPSD has alleged, among other things, that the poles were overloaded, that the OII Respondents violated the CPUC's rules governing the design, construction and inspection of poles and misled the CPUC during its investigation of the fire, and that SCE failed to preserve evidence relevant to the investigation. In October 2011, the CPSD proposed that the OII Respondents be assessed penalties of approximately $99 million, with SCE being allocated approximately $50 million of the total. SCE has denied the allegations and believes the proposed penalties are excessive.

Four Corners New Source Review Litigation

In October 2011, four private environmental organizations filed a CAA citizen lawsuit against the co-owners of Four Corners. The complaint alleges that certain work performed at the Four Corners generating units 4 and 5, over the approximate periods of 1985-1986 and 2007-present, constituted plant “major modifications” and the plant's failure to obtain permits and install best available control technology ("BACT") violated the PSD requirements and the New Source Performance Standards of the CAA. The complaint also alleges subsequent and continuing violations of BACT air emissions limits. The lawsuit seeks injunctive and declaratory relief, civil penalties, including a mitigation project and litigation costs. In November 2010, SCE entered into an agreement to sell its ownership interest in generating units 4 and 5 to APS. The sale is subject to certain closing conditions and is expected to close in late 2012. Under the agreement SCE would remain responsible for its pro rata share of certain environmental liabilities, including penalties arising from environmental violations prior to the sale, but SCE would not be liable for any costs of installing BACT or other costs related to continuing or extending Four Corners operations. SCE is unable to estimate a possible loss or range of loss associated with this matter.

Concurrently, the US EPA has proposed a regional haze federal implementation plan based on an APS proposal that would require shut down of units 1, 2 and 3 by 2016 and the installation of selective catalytic reduction technology on units 4 and 5 by 2018. APS' proposal contemplated that these actions would both satisfy the federal regional haze requirements and resolve any New Source Review claims the US EPA might have. A final federal implementation plan is expected in 2012.

Environmental Remediation

Edison International records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operation and maintenance, monitoring and site closure. Unless there is a single probable amount, Edison International records the lower end of this reasonably likely range of costs (reflected in "Other long-term liabilities") at undiscounted amounts as timing of cash flows is uncertain. At March 31, 2012, Edison International's recorded estimated minimum liability to remediate its 27 identified material sites (sites in which the upper end of the range of the costs is at least $1 million) at SCE (25 sites) and EMG (2 sites related to Midwest Generation) was $51 million, of which $43 million was related to SCE, including $12 million related to San Onofre. In addition to its identified material sites, SCE also has 33 immaterial sites for which the total minimum recorded liability was $3 million. Of the $46 million total environmental remediation liability for SCE, $43 million has been recorded as a regulatory asset. SCE expects to recover $27 million through an incentive mechanism that allows SCE to recover 90% of its environmental remediation costs at certain sites (SCE may request to include additional sites) and $16 million through a mechanism that allows SCE to recover 100% of the costs incurred at certain sites through customer rates. Edison International's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that Edison International may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

30

The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs at the identified material sites and immaterial sites could exceed its recorded liability by up to $214 million and $5 million, respectively, all of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next five years are expected to range from $7 million to $17 million. Costs incurred for the three months ended March 31, 2012 and 2011 were $2 million and $4 million, respectively.

Based upon the CPUC's regulatory treatment of environmental remediation costs incurred at SCE, Edison International believes that costs ultimately recorded will not materially affect its results of operations, financial position or cash flows. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to estimates.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $12.6 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($375 million). The balance is covered by a loss sharing program among nuclear reactor licensees. If a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site, all nuclear reactor licensees could be required to contribute their share of the liability in the form of a deferred premium.

Based on its ownership interests, SCE could be required to pay a maximum of approximately $235 million per nuclear incident. However, it would have to pay no more than approximately $35 million per incident in any one year. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further federal revenue.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and excess property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than the federal requirement of a minimum of approximately $1.1 billion. Property damage insurance also covers damages caused by acts of terrorism up to specified limits. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by entities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to approximately $49 million per year. Insurance premiums are charged to operating expense.

Wildfire Insurance

Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. On September 1, 2011, SCE's parent, Edison International, renewed its insurance coverage, which included coverage for SCE's wildfire liabilities up to a $575 million limit (with a self-insured retention of $10 million per wildfire occurrence). Various coverage limitations within the policies that make up the insurance coverage could result in additional self-insured costs in the event of multiple wildfire occurrences during the policy
period (September 1, 2011 to August 31, 2012). SCE may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's insurance coverage.

Spent Nuclear Fuel

Under federal law, the Department of Energy ("DOE") is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. Currently, both San Onofre and Palo Verde have interim storage for spent nuclear fuel on site sufficient for the current license period.

31

In June 2010, the United States Court of Federal Claims issued a decision granting SCE and the San Onofre co-owners damages of approximately $142 million to recover costs incurred through December 31, 2005 for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. SCE received payment from the federal government in the amount of the damage award in November 2011. SCE has returned to the San Onofre co-owners their respective share of the damage award paid. SCE, as operating agent, filed a lawsuit on behalf of the San Onofre owners against the DOE in the Court of Federal Claims in December 2011 seeking damages of approximately $98 million for the period from January 1, 2006 to December 31, 2010 for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel. Additional legal action would be necessary to recover damages incurred after December 31, 2010. Any damages recovered by SCE are subject to CPUC review as to how these amounts would be distributed among customers, shareholders, or to offset fuel decommissioning or storage costs.

Note 10. Environmental Developments

Hazardous Air Pollutant Regulations

In December 2011, the US EPA announced the Mercury and Air Toxics Standards ("MATS") rule, limiting emissions of hazardous air pollutants from coal- and oil-fired electrical generating units. The rule was published in the Federal Register on February 16, 2012, and became effective on April 16, 2012. A number of parties have filed notices of appeal challenging the rule.

Greenhouse Gas Regulation

In March 2012, the US EPA announced proposed carbon dioxide emissions limits for new power plants. The status of the US EPA's efforts to develop greenhouse gas emissions performance standards for existing plants is unknown.

Greenhouse Gas Litigation

In March 2012, the federal district court in Mississippi dismissed, in its entirety, the purported class action complaint filed by private citizens in May 2011, naming a large number of defendants, including SCE and other Edison International subsidiaries, for damages allegedly arising from Hurricane Katrina. In April 2012, the plaintiffs filed an appeal with the Fifth Circuit Court of Appeals. Plaintiffs allege that the defendants' activities resulted in emissions of substantial quantities of greenhouse gases that have contributed to climate change and sea level rise, which in turn are alleged to have increased the destructive force of Hurricane Katrina. The lawsuit alleges causes of action for negligence, public and private nuisance, and trespass, and seeks unspecified compensatory and punitive damages. The claims in this lawsuit are nearly identical to a subset of the claims that were raised against many of the same defendants in a previous lawsuit that was filed in, and dismissed by, the same federal district court where the current case has been filed.

Note 11. Accumulated Other Comprehensive Loss

Edison International's accumulated other comprehensive loss consists of:

(in millions)	Unrealized Gain (Loss) on Cash Flow Hedges	Pension and PBOP – Net Loss	Pension and PBOP – Prior Service Cost	Accumulated Other Comprehensive Loss
Balance at December 31, 2011	$ (34)	$ (100)	$ (5)	$ (139)
Change for 2012	14	7	—	21
Balance at March 31, 2012	$ (20)	$ (93)	$ (5)	$ (118)

Included in accumulated other comprehensive loss at March 31, 2012 was $27 million, net of tax, of unrealized gains on commodity-based cash flow hedges, and $47 million, net of tax, of unrealized losses related to interest rate hedges. The maximum period over which a commodity cash flow hedge is designated is through May 31, 2014.

Unrealized gains on commodity hedges consist of futures and forward electricity contracts that qualify for hedge accounting. These gains arise because current forecasts of future electricity prices in these markets are lower than the contract prices. Approximately $28 million of unrealized gains on cash flow hedges, net of tax, are expected to be reclassified into earnings during the next 12 months. Management expects that reclassification of net unrealized gains will increase energy revenues recognized at market prices. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions.

32

Note 12. Supplemental Cash Flows Information

Edison International's supplemental cash flows information is:

	Three months ended March 31,	
(in millions)	2012	2011
Cash payments (receipts) for interest and taxes:		
Interest – net of amounts capitalized	$ 157	$ 155
Tax payments (refunds) – net	(3)	(45)
Dividends declared but not paid:		
Common stock	$ 106	$ 104
Preferred and preference stock	10	10

Accrued capital expenditures at March 31, 2012 and 2011 were $419 million and $461 million, respectively. Accrued capital expenditures will be included as an investing activity in the consolidated statements of cash flow in the period paid.

Note 13. Preferred and Preference Stock of Utility

During the first quarter of 2012, SCE issued 350,000 shares of 6.25% Series E preference stock (cumulative, $1,000 liquidation value). The Series E preference shares may not be redeemed prior to February 1, 2022. After February 1, 2022, SCE may at its option, redeem the shares, in whole or in part for a price of $1,000 per share plus accrued and unpaid dividends, if any. The shares are not subject to mandatory redemption. The proceeds from the sale of these shares were used to repay commercial paper borrowings and to fund SCE's capital program.

Note 14. Regulatory Assets and Liabilities

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

(in millions)	March 31, 2012	December 31, 2011
Current:		
Regulatory balancing accounts	$ 362	$ 223
Energy derivatives	320	264
Other	10	7
Total Current	692	494
Long-term:		
Deferred income taxes – net	2,056	2,020
Pensions and other postretirement benefits	1,688	1,703
Energy derivatives	728	487
Unamortized investment – net	497	484
Unamortized loss on reacquired debt	244	249
Nuclear-related investment – net	152	156
Regulatory balancing accounts	84	69
Other	264	298
Total Long-term	5,713	5,466
Total Regulatory Assets	$ 6,405	$ 5,960

33

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

(in millions)	March 31, 2012	December 31, 2011
Current:		
Regulatory balancing accounts	$637	$661
Other	8	9
Total Current	645	670
Long-term:		
Costs of removal	2,736	2,697
Asset Retirement Obligations	1,322	1,105
Regulatory balancing accounts	1,039	864
Other	6	4
Total Long-term	5,103	4,670
Total Regulatory Liabilities	$5,748	$5,340

Note 15. Other Investments

Nuclear Decommissioning Trusts

Future decommissioning costs of removal of nuclear assets are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately $23 million per year through SCE customer rates. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates. Funds collected,
together with accumulated earnings, will be utilized solely for decommissioning. The CPUC has set certain restrictions related to the investments of these trusts.

The following table sets forth amortized cost and fair value of the trust investments:

		Amortized Cost		Fair Value	
(in millions)	Longest Maturity Dates	March 31, 2012	December 31, 2011	March 31, 2012	December 31, 2011
Stocks	—	$885	$ 865	$2,124	$ 1,899
Municipal bonds	2051	574	625	696	756
U.S. government and agency securities	2041	596	516	642	580
Corporate bonds	2054	305	259	369	317
Short-term investments and receivables/payables	One-year	21	38	22	40
Total		$2,381	$ 2,303	$3,853	$ 3,592

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Proceeds from sales of securities (which are reinvested) were $602 million and $622 million for the three months ended March 31, 2012 and 2011, respectively. Unrealized holding gains, net of losses, were $1.5 billion and $1.3 billion at March 31, 2012 and December 31, 2011, respectively.

34

The following table sets forth a summary of changes in the fair value of the trust:

	Three months ended March 31,	
(in millions)	2012	2011
Balance at beginning of period	$3,592	$3,480
Gross realized gains	25	23
Gross realized losses	(4)	—
Unrealized gains (losses) – net	184	102
Other-than-temporary impairments	(5)	(9)
Interest, dividends, contributions and other	61	23
Balance at end of period	$3,853	$3,619

Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on operating revenue or earnings.

Note 16. Other Income and Expenses

Other income and expenses are as follows:

	Three months ended March 31,	
(in millions)	2012	2011
Other income:		
Equity allowance for funds used during construction	$20	$29
Increase in cash surrender value of life insurance policies	7	7
Other	4	2
Total utility other income	31	38
Competitive power generation and other income	—	3
Total other income	$31	$41
Other expenses:		
Civic, political and related activities and donations	$6	$7
Other	3	6
Total utility other expenses	9	13
Competitive power generation and other expenses	1	—
Total other expenses	$10	$13

Note 17. Business Segments

The following is information (including the elimination of intercompany transactions) related to Edison International's reportable segments:

(in millions)	Three months ended March 31, 2012	2011
Operating Revenue:		
Electric utility	$2,412	$2,232
Competitive power generation	444	552
Parent and other[2]	—	(2)
Consolidated Edison International	$2,856	$2,782
Net Income (Loss) attributable to Edison International:		
Electric utility	$182	$222
Competitive power generation[1]	(84)	(20)
Parent and other[2]	(5)	(2)
Consolidated Edison International	$93	$200

Segment balance sheet information was:

(in millions)	March 31, 2012	December 31, 2011
Total Assets:		
Electric utility	$41,605	$40,315
Competitive power generation	8,472	8,392
Parent and other[2]	(693)	(668)
Consolidated Edison International	$49,384	$48,039

1 Includes losses from discontinued operations of $(1) million and $(2) million for the three months ended March 31, 2012 and 2011, respectively.

2 Includes amounts from Edison International (parent) and other Edison International subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

36

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FORWARD-LOOKING STATEMENTS

This quarterly report on Form 10-Q contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements reflect Edison International's current expectations and projections about future events based on Edison International's knowledge of present facts and circumstances and assumptions about future events and include any statement that does not directly relate to a historical or current fact. Other information distributed by Edison International that is incorporated in this report, or that refers to or incorporates this report, may also contain forward-looking statements. In this report and elsewhere, the words "expects," "believes," "anticipates," "estimates," "projects," "intends," "plans," "probable," "may," "will," "could," "would," "should," and variations of such words and similar expressions, or discussions of strategy or of plans, are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ from those currently expected, or that otherwise could impact Edison International, include, but are not limited to:

- cost of capital and the ability of Edison International or its subsidiaries to borrow funds and access the capital markets on reasonable terms;
- environmental laws and regulations, at both state and federal levels, or changes in the application of those laws, that could require additional expenditures or otherwise affect the cost and manner of doing business, including compliance with CPS (at Midwest Generation) and CAIR or CSAPR (as applicable) and the MATS rule at Midwest Generation and Homer City;
- ability of SCE to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;
- possible customer bypass or departure due to technological advancements or cumulative rate impacts that make self-generation or use of alternative energy sources economically viable;
- risks associated with the operation of transmission and distribution assets and nuclear and other power generating facilities including: nuclear fuel storage issues, public safety issues, failure, availability, efficiency, output, cost of repairs and retrofits of equipment and availability and cost of spare parts;
- ability of EMG to meet its liquidity requirements and stabilize its capital structure during periods of operating losses;
- the completion of the transactions for the divestiture of Homer City's leasehold interest and related assets and liabilities pursuant to the terms of the Implementation Agreement between Homer City and GECC, and the timing and structure of such transactions;
- cost and availability of electricity, including the ability to procure sufficient resources to meet expected customer needs in the event of nuclear or other power plant outages or significant counterparty defaults under power-purchase agreements;
- changes in the fair value of investments and other assets;
- changes in interest rates and rates of inflation, including those rates which may be adjusted by public utility regulators;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market and price mitigation strategies adopted by Independent System Operators and Regional Transmission Organizations;
- availability and creditworthiness of counterparties and the resulting effects on liquidity in the power and fuel markets and/or the ability of counterparties to pay amounts owed in excess of collateral provided in support of their obligations;
- cost and availability of labor, equipment and materials;

37

- ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities and wildfire-related liability, and to recover the costs of such insurance;
- ability to recover uninsured losses in connection with wildfire-related liability;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;
- potential for penalties or disallowances caused by non-compliance with applicable laws and regulations;
- cost and availability of coal, natural gas, fuel oil, and nuclear fuel, and related transportation to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;
- cost and availability of emission credits or allowances for emission credits;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- ability to provide sufficient collateral in support of hedging activities and power and fuel purchased;
- risks inherent in the construction of transmission and distribution infrastructure replacement and expansion projects, including those related to project site identification, public opposition, environmental mitigation, construction, permitting, power curtailment costs (payments due under power contracts in the event there is insufficient transmission to enable the acceptance of power delivery), and governmental approvals;
- risks that competing transmission systems will be built by merchant transmission providers in SCE's service area; and
- weather conditions and natural disasters.

Additional information about risks and uncertainties, including more detail about the factors described above, is contained throughout this MD&A and in Edison International's 2011 Form 10-K, including the "Risk Factors" section in Part I, Item 1A. Readers are urged to read this entire report, including the information incorporated by reference, as well as the 2011 Form 10-K, and carefully consider the risks, uncertainties and other factors that affect Edison International's business. Forward-looking statements speak only as of the date they are made and Edison International is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by Edison International with the U.S. Securities and Exchange Commission.

The MD&A for the three months ended March 31, 2012 discusses material changes in the consolidated financial condition, results of operations and other developments of Edison International since December 31, 2011, and as compared to the three months ended March 31, 2011. This discussion presumes that the reader has read or has access to Edison International's MD&A for the calendar year 2011 (the "year-ended 2011 MD&A"), which was included in the 2011 Form 10-K.

EDISON INTERNATIONAL OVERVIEW

Highlights of Operating Results

(in millions)	Three months ended March 31, 2012	2011	Change
Net Income (Loss) attributable to Edison International			
SCE	$ 182	$ 222	$ (40)
EMG	(84)	(20)	(64)
Edison International Parent and Other	(5)	(2)	(3)
Edison International Consolidated	93	200	(107)
Less: Non-Core Items			
EMG Homer City	(23)	(10)	(13)
EMG discontinued operations	(1)	(2)	1
Total non-core items	(24)	(12)	(12)
Core Earnings (Losses)			
SCE	182	222	(40)
EMG	(60)	(8)	(52)
Edison International Parent and Other	(5)	(2)	(3)
Edison International Consolidated	$ 117	$ 212	$ (95)

Edison International's earnings are prepared in accordance with generally accepted accounting principles used in the United States. Management uses core earnings by principal operating subsidiary internally for financial planning and for analysis of performance. Core earnings (losses) by principal operating subsidiary are also used when communicating with analysts and investors regarding Edison International's earnings results to facilitate comparisons of the Company's performance from period to period. Core earnings (losses) are a non-GAAP financial measure and may not be comparable to those of other companies. Core earnings (losses) are defined as earnings attributable to Edison International shareholders less income or loss from discontinued operations and income or loss from significant discrete items that management does not consider representative of ongoing earnings, such as: exit activities, including lease terminations, sale of certain assets, early debt extinguishment costs and other activities that are no longer continuing; asset impairments and certain tax, regulatory or legal settlements or proceedings. EMG classified the results of Homer City, including the costs incurred in connection with the expected divestiture, as non-core for both the first quarter of 2012 and 2011 due to the plan described below to transition ownership of the leasehold interest to the owner-lessors.

SCE's 2012 core earnings decreased $40 million primarily due to a delay in the 2012 CPUC General Rate Case decision as higher depreciation and net interest expenses are not being recovered in currently authorized revenue. The revenue requirement ultimately adopted by the CPUC will be retroactive to January 1, 2012. The variance also reflects a lower capitalization rate on funds used during construction. SCE has incurred $20 million of incremental steam generator inspection and repair costs related to outages at San Onofre which were offset by other operation and maintenance cost reductions.

EMG's 2012 core losses increased $52 million due to lower average realized energy and capacity prices and lower generation at the Midwest Generation plant and higher interest expense related to new energy project financings.

Consolidated non-core items for 2012 and 2011 for Edison International include the results for Homer City in anticipation of the orderly transfer of the Homer City plant to the owner-lessors, which will result in EMG's loss of substantially all beneficial economic interest in and material control of the Homer City plant.

Management Overview of SCE

2012 CPUC General Rate Case

As discussed in the year-ended 2011 MD&A, SCE filed its 2012 GRC application in November 2010. In October 2011, SCE submitted updated testimony, which changed SCE's requested 2012 base rate revenue requirement to $6.3 billion. The Division of Ratepayer Advocates, The Utility Reform Network and other intervenors recommended substantially less than the

39

amount requested by SCE. Intervenors have also recommended changes to SCE's proposed post-test year ratemaking methodology to be used for 2013 and 2014 as well as limiting the recovery amount of SCE's pension costs. A decision on the GRC is expected in the second quarter of 2012. SCE is currently recognizing revenue largely based on the 2011 authorized revenue requirement, however, the CPUC has authorized the establishment of a GRC memorandum account, which will make the 2012 revenue requirement ultimately adopted by the CPUC effective as of January 1, 2012.

San Onofre Outage, Inspection and Repair Issues

As discussed in the 2011 Form 10-K, in the first quarter of 2012, isolated areas of wear in some of the heat transfer tubes in San Onofre's Unit 2 steam generators were found during a planned outage and a water leak was detected in one of the tubes in a Unit 3 steam generator. Unit 3 was safely taken offline and both Units remain offline for ongoing, extensive inspections, testing and analysis.

The water leak in the Unit 3 steam generator was caused by excessive wear resulting from tube-to-tube contact in the area of the leak. Causal analysis of the tube to tube contact continues. The same area was re-inspected in the Unit 2 steam generators using a more sensitive inspection method and similar tube-to-tube wear was found on two tubes in one of the steam generators at wear levels below the detection capability of the initial testing. Earlier tests performed on the Unit 2 steam generators during the planned outage additionally found high levels of wear in some tubes that were in contact with a tube support structure. As a result, all tubes in contact with the support structure in both Unit 2 steam generators were preventively removed from service through plugging. Subsequent inspections on Unit 3 found similar tube-to-support structure wear, and the affected tubes will also be plugged preventively.

During the inspection and testing of the steam generators, additional pressure tests of certain tubes were completed to determine the safety significance of the wear. Eight of the 129 tubes subjected to the additional tests failed the tests and the NRC was notified as required. Given these test results, the NRC launched an Augmented Inspection Team to assess the tube failures and their causes, SCE's operation of the Units, and SCE's oversight of the design, fabrication, shipping, and construction process. The efforts of the Augmented Inspection Team remain in progress. Should the NRC find a deficiency in SCE's performance, SCE could be subject to additional regulatory action by the NRC, and the findings could be taken into consideration in the CPUC regulatory proceedings described below. In March 2012, the NRC issued a confirmatory action letter that required NRC permission to restart Unit 2 and Unit 3 and outlined actions SCE must complete. Each Unit will only be restarted when repairs and appropriate mitigation plans on that Unit are completed in accordance with the NRC's letter, and SCE is satisfied that it is safe to do so.

In 2005, the CPUC authorized expenditures of approximately $525 million ($665 million when adjusted for inflation) for SCE's 78.21% share of San Onofre to purchase and install the four new steam generators in Units 2 and 3 and remove and dispose of their predecessors. SCE has spent $592 million through March 31, 2012 on the steam generator replacement project. Those expenditures remain subject to CPUC review upon submission of SCE's final costs for the overall project. Replacement power costs are recovered through the ERRA balancing account, subject to reasonableness review. Replacement power costs for outages associated with the steam generator inspection and repair (commencing on February 1 for Unit 3 and March 5 for Unit 2) through March 31, 2012 were approximately $30 million. Total replacement power costs will not be known until the Units are returned to service, but costs for power are likely to be higher during the summer months should replacement power still be required at that time. Through mid-April 2012, incremental inspection and repair costs totaled $30 million. Subject to NRC review under the confirmatory action letter and any new developments that may result from further analysis, testing and inspection, SCE's estimated share of the total incremental inspection and repair costs associated with returning the units to service remains uncertain, but is currently projected to be in the range of $55 million to $65 million.

The steam generators were supplied by Mitsubishi Heavy Industries (“MHI”) and are warranted for an initial period of 20 years from acceptance. Subject to certain exceptions, the purchase agreement obligates MHI to repair or replace defective items, sets forth specified damages for certain repairs, and provides that MHI's liability under the purchase agreement is generally limited to $137 million in the aggregate and excludes consequential damages, defined to include the cost of replacement power.

2013 Cost of Capital Application

In April 2012, SCE filed its 2013 cost of capital application requesting a ratemaking capital structure of 43% long-term debt, 9% preferred equity and 48% common equity consistent with the current capital structure. In addition, SCE is proposing to reduce its current cost of capital as follows: cost of long-term debt from 6.22% to 5.53%, authorized cost of preferred equity from 6.01% to 5.86% and authorized return on common equity from 11.5% to 11.1%. SCE estimates that this request will result in a revenue requirement reduction of $128 million. The application requests continuation of the current multi-year

40

mechanism, which would retain the authorized capital structure through 2015. The cost of capital will be subject to annual adjustments if certain thresholds are reached. SCE is seeking a CPUC decision on its application by the end of 2012.

Capital Program

During the first three months of 2012, SCE's capital investment program focused on maintaining reliability and expanding the capability of SCE's transmission and distribution system; upgrading and constructing new transmission lines and substations; installing digital meters; and replacing generation asset equipment. Total capital expenditures (including accruals) were $839 million during the first three months of 2012 compared to $765 million during the same period in 2011.

As discussed under "Liquidity and Capital Resources—Capital Investment Plan" in the year-ended 2011 MD&A, SCE continues to project that 2012 capital expenditures will be in the range of $4.4 billion to $5.0 billion and that 2012 – 2014 total capital expenditures will be in the range of $11.8 billion to $13.2 billion. Actual capital spending will be affected by: changes in regulatory, environmental and engineering design requirements; permitting and project delays; cost and availability of labor, equipment and materials; and other factors.

Management Overview of EMG

EMG's operating results were lower in the first quarter of 2012 compared to the first quarter of 2011 due to lower realized energy and capacity prices at its coal plants and lower generation at the Midwest Generation plants. The abundance of low-priced natural gas has continued to result in increased competition from natural gas-fired generating units in the markets in which Midwest Generation operates, and generation from Midwest Generation's plants has been correspondingly affected. Effective January 1, 2012, a favorable long-term rail contract that supplied Midwest Generation's fleet expired and was replaced by a higher priced contract. EMG expects that Midwest Generation's average fuel cost ($/MWh) will increase by approximately one-third in 2012.

At March 31, 2012, EME and its subsidiaries without contractual dividend restrictions, had corporate cash and cash equivalents of $927 million and Midwest Generation had cash and cash equivalents of $230 million and $500 million of available borrowing capacity under its credit facility maturing in June 2012. EME terminated its revolving credit facility in February 2012, and there can be no assurance that Midwest Generation will be eligible to draw on its credit facility prior to maturity. Any replacements of these credit lines will likely be on less favorable terms and conditions, and there is no assurance that EME will, or will be able to, replace these credit lines or any portion of them. In conjunction with the termination of its credit facility, EME entered into replacement letter of credit facilities secured by cash collateral. EME had $3.7 billion of unsecured notes outstanding at March 31, 2012, $500 million of which mature in 2013.

Unless energy and capacity prices increase substantially, EMG expects that it will incur further reductions in cash flow and losses in years subsequent to 2012 as well as in 2012, and a continuation of these adverse trends coupled with pending debt maturities and the need to retrofit its plants to comply with governmental regulations will strain EMG's liquidity. To address such scenario, EMG would need to consider all options available to it, including potential sales of assets or restructurings or reorganization of the capital structure of EME and its subsidiaries.

Midwest Generation Environmental Compliance Plans and Costs

During the first quarter of 2012, Midwest Generation continued to develop and implement a compliance program that includes the operation of activated carbon injection systems, upgrades to particulate removal systems and the use of dry sorbent injection, combined with the use of low sulfur PRB coal, to meet emissions limits for criteria pollutants, such as NO_x and SO_2 as well as for hazardous air pollutants, such as mercury, acid gas and non-mercury metals.

EMG has decided to shut down its Fisk and Crawford Stations in September 2012. The shut downs also have been approved by PJM, the regional transmission organization that controls the area where these plants are located. In total, Midwest Generation estimates that 150 to 180 employees will be affected. The timing and amount of severance benefits, if any, will be determined after completion of an ongoing review of personnel based on seniority and other factors. Severance benefits are not required under the existing collective bargaining agreement. Midwest Generation has sold capacity forward through May 31, 2015 for both Fisk and Crawford. However, Midwest Generation has not sold its full capacity forward during those periods. Midwest Generation would expect to cover its capacity obligations associated with the Fisk and Crawford units through a combination of improved fleet performance, fleet capacity not previously sold forward and, if necessary, market transactions. In connection with the shut down of these stations, EMG expects to receive a tax deduction equal to its tax basis in the facilities, although realization of these tax benefits may not occur for several years. At March 31, 2012, the tax basis of the Fisk and Crawford Stations were $64 million and $87 million, respectively.

Decisions regarding whether or not to proceed with retrofitting any particular remaining units to comply with CPS

requirements for SO_2 emissions, including those that have received permits, are subject to a number of factors, such as market conditions, regulatory and legislative developments, liquidity and forecasted commodity prices and capital and operating costs applicable at the time decisions are required or made. Midwest Generation may also elect to shut down units, instead of installing controls, to be in compliance with the CPS. Final decisions on whether to install controls, to install particular kinds of controls, and to actually expend capital or continue with the expenditure of capital will be made as required, subject to the requirements of the CPS and other applicable regulations. Units that are not retrofitted may continue to operate until required to shut down by applicable regulations or operate with reduced output.
Based on work to date, Midwest Generation estimates the cost of retrofitting the large stations (Powerton, Joliet Units 7 and 8 and Will County) using dry scrubbing with sodium-based sorbents to comply with CPS requirements for SO_2 emissions, and the associated upgrading of existing particulate removal systems, would be up to approximately $628 million. The cost of retrofitting Joliet Unit 6 is not included in the large unit amounts as it is less likely that Midwest Generation will make retrofits for this unit. The estimated cost of retrofitting Joliet Unit 6, if made, would be approximately $75 million, while the estimated cost of retrofitting the Waukegan Station, if made, would be approximately $160 million. For further discussion related to the impairment policy on Midwest Generation's unit of account, refer to "Critical Accounting Estimates and Policies—Impairment of Long-Lived Assets" in the year-ended 2011 MD&A.
Homer City Lease
Homer City is not expected to have sufficient cash flow to meet its obligations, including funding capital improvements. Homer City made the required April 1, 2012 senior rent payment but did not make the April 1, 2012 payment of equity rent. On March 30, 2012, Homer City was granted a waiver by the owner-lessors of any rent default event with respect to the payment of the equity rent for all purposes other than restrictions on distributions from Homer City, including repayment of its intercompany loan, and the $48 million senior rent reserve letter of credit remains in place. Homer City's liquidity has continued to deteriorate during the first quarter of 2012. Absent a working capital loan or other infusion of cash, Homer City is not expected to have sufficient cash flow to meet its operating expenses and other obligations either in the near term or during 2012, including the rent payment due on October 1, 2012. This may require Homer City to temporarily suspend plant operations until sufficient working capital is obtained. For further discussion of the Homer City lease, see "Edison International Overview—Management Overview of EMG—Homer City Lease" in the year-ended 2011 MD&A.
Homer City has been engaged in discussions with the owner-lessors through GECC, beneficial owner of a majority of the owner-participants, regarding the funding of capital improvements at the Homer City plant and transfer to an affiliate of GECC of the economic benefit and majority ownership of all the operating assets of Homer City. On March 29, 2012, Homer City and GECC entered into an Implementation Agreement (the "Agreement") with respect to the Homer City plant. As addressed by the Agreement, an affiliate of the GECC-controlled owner-lessors of the Homer City plant has entered into an engineering, procurement and construction agreement and is in the process of executing related agreements for the construction of environmental improvements. GECC will have discretion over all decisions related to such agreements. Homer City agreed to conduct its business as set forth in the Agreement and to use commercially reasonable efforts to provide assistance to GECC and its affiliates in connection with the construction agreements. The Agreement also requires Homer City, at the request of GECC, to enter into one or more implementation transactions, as defined in the Agreement, for the divestiture of its leasehold interest in the Homer City plant (and, under certain circumstances, related assets and liabilities as specified) and to assist GECC in obtaining certain third-party consents or waivers. Homer City and GECC also agreed to enter into a transition services agreement in connection with any implementation transaction. The estimated cost of installing SO_2 and particulate emissions control equipment for Units 1 and 2 of the Homer City plant is expected to be approximately $700 million to $750 million. On April 2, 2012, Homer City received the permit to construct such improvements from PADEP. There is no assurance that Homer City and GECC will actually consummate a divestiture transaction as contemplated by the Agreement.
Certain divestitures of Homer City's leasehold interest in the plant are subject to consent rights of the holders of the secured lease obligation bonds issued in connection with the original sale-leaseback transaction. GECC is currently engaged in discussions and has reached an agreement in principle on a non-binding restructuring term sheet with

certain of the holders of the secured lease obligation bonds regarding amendments to the terms of the 8.137% Senior Secured Bonds due 2019 and the 8.734% Senior Secured Bonds due 2026, each issued by Homer City Funding LLC. Even though an agreement in principle has been reached with certain holders of secured lease obligation bonds, that agreement may not be approved by the secured lease obligation bondholders as required under the operative documents to effectuate the necessary modifications to the terms of the bonds. If an agreement to modify the terms of the bonds is not approved and consummated in a timely manner, then the protections of Chapter 11 of the U.S. Bankruptcy Code may be necessary.

Environmental Developments

For a discussion of environmental developments, see "Edison International Notes to Consolidated Financial Statements—Note 10. Environmental Developments."

SOUTHERN CALIFORNIA EDISON COMPANY
RESULTS OF OPERATIONS
SCE's results of operations are derived mainly through two sources:

- Utility earning activities – representing revenue authorized by the CPUC and FERC which is intended to provide SCE a reasonable opportunity to recover its costs and earn a return on its net investment in generation, transmission and distribution assets. The annual revenue requirements are comprised of authorized operation and maintenance costs, depreciation, taxes and a return consistent with the capital structure. Also, included in utility earnings activities are revenues or penalties related to incentive mechanisms, other operating revenue, and regulatory charges or disallowances, if any.
- Utility cost-recovery activities – representing CPUC- and FERC-authorized balancing accounts which allow for recovery of specific project or program costs, subject to reasonableness review or compliance with upfront standards.

During the first quarter of 2012, SCE classified revenues and costs related to EdisonSmartConnect®, San Onofre steam generator replacement project and similar programs that provide for recovery of actual costs plus a return on capital as utility earning activities. Previously, SCE classified the recovery of actual costs incurred under these programs as utility cost-recovery activities. The table presented below reflects a reclassification of the revenues and costs for the first quarter of 2011 consistent with the presentation in 2012. The reclassification of revenues and costs had no impact on earnings.

The following table is a summary of SCE's results of operations for the periods indicated. The presentation below separately identifies utility earning activities and utility cost-recovery activities.

	Three months ended March 31, 2012			Three months ended March 31, 2011		
(in millions)	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated	Utility Earning Activities	Utility Cost-Recovery Activities	Total Consolidated
Operating revenue	$1,456	$956	$2,412	$1,405	$827	$2,232
Fuel and purchased power	—	692	692	—	584	584
Operations and maintenance	588	263	851	542	242	784
Depreciation decommissioning and amortization	389	—	389	344	—	344
Property taxes and other	82	1	83	76	1	77
Total operating expenses	1,059	956	2,015	962	827	1,789
Operating income	397	—	397	443	—	443
Net interest expense and other	(97)	—	(97)	(84)	—	(84)
Income before income taxes	300	—	300	359	—	359
Income tax expense	99	—	99	123	—	123
Net income	201	—	201	236	—	236
Dividends on preferred and preference stock	19	—	19	14	—	14
Net income available for common stock	$182	$—	$182	$222	$—	$222
Core Earnings[1]			$182			$222
Non-Core Earnings			—			—
Total SCE GAAP Earnings			$182			$222

[1] See use of Non-GAAP financial measures in "Edison International Overview—Highlights of Operating Results."

Utility Earning Activities

During the first quarter of 2012, SCE recognized revenue from CPUC activities largely based on 2011 authorized base revenue requirements included in customer rates pending the outcome of the GRC. The CPUC has authorized the establishment of a GRC memorandum account, which will make the 2012 revenue requirement ultimately adopted by the

44

CPUC effective as of January 1, 2012. Recognition of the revenue for the period January 1, 2012 through the date of a final decision, as well as any delays in certain expenditures and changes in authorized treatment of specific costs, will impact the timing of earnings in 2012 (see "Edison International Overview—Management Overview of SCE—2012 CPUC General Rate Case" for further discussion).

Utility earning activities were primarily affected by the following:

- SCE had higher operating revenue of $51 million, primarily due to the following:
- $40 million increase was primarily due to revenue related to authorized CPUC projects not included in SCE's GRC process including the EdisonSmartConnect® project, San Onofre steam generator replacement project and the Solar Photovoltaic project.
- Revenue recognized in 2012 related to the San Onofre Unit 2 scheduled outage costs. In December 2011, the CPUC authorized revenue requirements for 2012 refueling outages for San Onofre.
- Higher operation and maintenance expense of $46 million was primarily due to $35 million of costs related to the 2012 San Onofre Unit 2 scheduled maintenance and refueling outage as well as $20 million related to the steam generator inspection and repair at San Onofre. These increases were partially offset by transmission and distribution reductions and EdisonSmartConnect® benefits realized. See "Edison International Overview—Management Overview of SCE—San Onofre Outage, Inspection and Repair Issues" for further information.
- Higher depreciation, decommissioning and amortization expense of $45 million was primarily related to increased transmission and distribution investments.
- Higher net interest expense and other of $13 million was primarily due to higher outstanding balances on long-term debt and a lower AFUDC capitalization rate in 2012 mainly driven by lower cost of financing resulting from an increase in the use of short-term debt. For details of other income and expenses, see "Edison International Notes to Consolidated Financial Statements—Note 15. Other Income and Expenses."
- Lower income taxes due to lower pre-tax income. See "—Income Taxes" below for more information.

Utility Cost-Recovery Activities

Utility cost-recovery activities were primarily affected by the following:

- Higher purchased power expense of $108 million was primarily driven by the cost to replace CDWR contracts that expired in 2011, which were not previously recorded as an SCE cost but which were included as a separate component on customer bills (see "—Supplemental Operating Revenue Information" below), and lower generation in 2012 from San Onofre. These increases were offset by lower power prices in 2012.

Supplemental Operating Revenue Information

SCE's retail billed and unbilled revenue (excluding wholesale sales and balancing account over/undercollections) was $2.3 billion and $2.1 billion for the three months ended March 31, 2012 and 2011 respectively. The increase in revenue reflects:

- a sales volume increase of $288 million primarily due to SCE providing power that was previously provided by CDWR contracts which expired in 2011. Prior to 2012, SCE remitted to CDWR and did not recognize as revenue the amounts that SCE billed and collected from its customers for the portion of electric power purchased and sold by the CDWR to SCE's customers.
- a rate decrease of $105 million resulting from a rate adjustment beginning on June 1, 2011, primarily reflecting the refund to customers of overcollected fuel and power procurement-related costs.

As a result of the CPUC-authorized decoupling mechanism, SCE earnings are not affected by changes in retail electricity sales (see "Item 1. Business—Overview of Ratemaking Process" in the 2011 Form 10-K).

Income Taxes

The table below provides a reconciliation of income tax expense computed at the federal statutory income tax rate to the income tax provision.

	Three months ended March 31,	
(in millions)	2012	2011
Income before income taxes	$300	$359
Provision for income tax at federal statutory rate of 35%	$105	$125
Increase (decrease) in income tax from:		
State tax – net of federal benefit	10	12
Property-related	(10)	(11)
Other	(6)	(3)
Total income tax expense	$99	$123
Effective tax rate	33.0%	34.3%

For a discussion of the status of Edison International's income tax audits, see "Edison International Notes to Consolidated Financial Statements—Note 7. Income Taxes."

LIQUIDITY AND CAPITAL RESOURCES

SCE's ability to operate its business, fund capital expenditures, and implement its business strategy are dependent upon its cash flow and access to the capital markets. SCE's overall cash flows fluctuate based on, among other things, its ability to recover its costs in a timely manner from its customers through regulated rates, changes in commodity prices and volumes, collateral requirements, interest and dividend payments to investors, and the outcome of tax and regulatory matters.

SCE expects to fund its 2012 obligations, capital expenditures and dividends through operating cash flows and capital market financings of debt and preferred equity, as needed. SCE also has availability under its credit facilities to meet operating and capital requirements.

Available Liquidity

SCE has two credit facilities: a $2.3 billion five-year credit facility that matures in February 2013 and a $500 million three-year credit facility that matures in March 2013. SCE expects to complete negotiations for a replacement credit facility with substantially similar terms and current market rates in 2012.

(in millions)	Credit Facilities
Commitment	$2,796
Outstanding commercial paper supported by credit facilities	(330)
Outstanding letters of credit	(63)
Amount available	$2,403

Debt Covenant

SCE has a debt covenant in its credit facilities that limits its debt to total capitalization ratio to less than or equal to 0.65 to 1. At March 31, 2012, SCE's debt to total capitalization ratio was 0.48 to 1.

Regulatory Proceedings

FERC Formula Rates

As discussed in the year-ended 2011 MD&A, the FERC has accepted, subject to refund and settlement procedures, SCE's request to implement formula rates as a means to determine SCE's FERC transmission revenue requirement effective January 1, 2012. SCE's request would result in a total 2012 FERC weighted average ROE of 11.1% including a base ROE of 9.93% and the previously authorized 50 basis point incentive for CAISO participation and individual authorized project incentives. The formula rate mechanism, including the base ROE, is subject to final resolution as part of the settlement process or, if a settlement is not achieved, to determination by FERC in a litigated process. SCE and the other parties to the proceeding continue to engage in settlement negotiations.

Dividend Restrictions

The CPUC regulates SCE's capital structure which limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the 48% authorized level on a 13-month weighted average basis. At March 31, 2012, SCE's 13-month weighted-average common equity component of total capitalization was 50.0% resulting in the capacity to pay $377 million in additional dividends to Edison International.

During the first quarter of 2012, SCE made $116 million in dividend payments to its parent, Edison International. Future dividend amounts and timing of distributions are dependent upon several factors including the level of capital expenditures, operating cash flows and earnings.

Margin and Collateral Deposits

Certain derivative instruments, power procurement contracts and other contractual arrangements contain collateral requirements. Future collateral requirements may differ from the requirements at March 31, 2012, due to the addition of incremental power and energy procurement contracts with collateral requirements, if any, and the impact of changes in wholesale power and natural gas prices on SCE's contractual obligations.

Some of the power procurement contracts contain provisions that require SCE to maintain an investment grade credit rating from the major credit rating agencies. If SCE's credit rating were to fall below investment grade, SCE may be required to pay the liability or post additional collateral.

The table below provides the amount of collateral posted by SCE to its counterparties as well as the potential collateral that would be required as of March 31, 2012.

(in millions)	
Collateral posted as of March 31, 2012[1]	$164
Incremental collateral requirements for power procurement contracts resulting from a potential downgrade of SCE's credit rating to below investment grade	140
Posted and potential collateral requirements[2]	$304

1 Collateral provided to counterparties and other brokers consisted of $81 million of cash which was offset against net derivative liabilities on the consolidated balance sheets, $20 million of cash reflected in "Other current assets" on the consolidated balance sheets and $63 million in letters of credit.

2 There would be no increase to SCE's total posted and potential collateral requirements based on SCE's forward positions as of March 31, 2012 due to adverse market price movements over the remaining lives of the existing power procurement contracts using a 95% confidence level.

Workers Compensation Self-Insurance Fund

For a discussion of potential collateral requirements related to its self-insured workers compensation plan, refer to "SCE: Liquidity and Capital Resources—Workers Compensation Self-Insurance Fund" in the year ended 2011 MD&A.

Historical Segment Cash Flows

The table below sets forth condensed historical cash flow information for SCE.

(in millions)	Three months ended March 31, 2012	2011
Net cash provided by operating activities	$775	$672
Net cash provided by financing activities	500	190
Net cash used by investing activities	(1,269)	(1,066)
Net increase (decrease) in cash and cash equivalents	$6	$(204)

Net Cash Provided by Operating Activities

Net cash provided by operating activities increased $103 million in the first quarter of 2012 compared to the same period in 2011. The increase in cash flows provided by operating activities was primarily due to the timing of cash receipts and disbursements related to working capital items, partially offset by lower net tax receipts in 2012.

Net Cash Provided by Financing Activities

The following table summarizes cash provided by financing activities for the three months ended March 31, 2012 and 2011. Issuances of debt and preference stock are discussed in "Edison International Notes to Consolidated Financial Statements—Note 5. Debt and Credit Agreements—Long-Term Debt" and "Note 12. Preferred and Preference Stock."

(in millions)	Three months ended March 31, 2012	2011
Issuances of preference stock, net	$345	$123
Issuances of first and refunding mortgage bonds, net	391	—
Payments of common stock dividends to Edison International	(116)	(115)
Payments of preferred and preference stock dividends	(15)	(13)
Net issuances of commercial paper[1]	(89)	200
Other	(16)	(5)
Net cash provided by financing activities	$500	$190

[1] Issuances of commercial paper are supported by SCE's line of credit.

The timing and amount of SCE's financing activities are largely driven by its capital program.

Net Cash Used by Investing Activities

Cash flows from investing activities are primarily due to capital expenditures and funding of nuclear decommissioning trusts. Capital expenditures were $1.2 billion and $1.0 billion for the three months ended March 31, 2012 and 2011, respectively (see "SCE: Liquidity and Capital Resources—Capital Investment Plan" in the year-ended 2011 MD&A for further information on capital expenditures). Net purchases of nuclear decommissioning trust investments and other were $82 million and $47 million for the three months ended March 31, 2012 and 2011, respectively.

Contractual Obligations and Contingencies

Contingencies

SCE has contingencies related to the CPSD Investigations, Four Corners New Source Review Litigation, Nuclear Insurance, Wildfire Insurance and Spent Nuclear Fuel, which are discussed in "Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

Environmental Remediation

As of March 31, 2012, SCE had identified 25 material sites for remediation and recorded an estimated minimum liability of $43 million. SCE expects to recover 90% of its remediation costs at certain sites. See "Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies" for further discussion.

MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms. Derivative instruments are used, as appropriate, to manage market risks for customers and SCE. For a further discussion of SCE's market risk exposures, including commodity price risk, credit risk and interest rate risk, see "Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities" and "—Note 4. Fair Value Measurements."

Commodity Price Risk

The fair value of outstanding derivative instruments used to mitigate SCE's exposure to commodity price risk was a net liability of $1.3 billion and $936 million at March 31, 2012 and December 31, 2011, respectively. The increase in the net liability was related to changes in unrealized losses on economic hedging activities primarily due to declining power and natural gas prices. For further discussion of fair value measurements and the fair value hierarchy, see "Edison International Notes to Consolidated Financial Statements—Note 4. Fair Value Measurements."

Credit Risk

Credit risk exposure from counterparties for power and gas trading activities is measured as the sum of net accounts receivable (accounts receivable less accounts payable) and the current fair value of net derivative assets (derivative assets less derivative liabilities) reflected on the consolidated balance sheets. SCE enters into master agreements which typically provide for a right of setoff. Accordingly, SCE's credit risk exposure from counterparties is based on a net exposure under these arrangements. SCE manages the credit risk on the portfolio for both rated and non-rated counterparties based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements, including master netting agreements. As of March 31, 2012, the amount of balance sheet exposure as described above broken down by the credit ratings of SCE's counterparties, was as follows:

	March 31, 2012		
(in millions)	Exposure[2]	Collateral	Net Exposure
S&P Credit Rating[1]			
A or higher	$101	$—	$101
A-	1	—	1
Not rated[3]	14	(4)	10
Total	$116	$(4)	$112

1 SCE assigns a credit rating based on the lower of a counterparty's S&P or Moody's rating. For ease of reference, the above table uses the S&P classifications to summarize risk, but reflects the lower of the two credit ratings.

2 Exposure excludes amounts related to contracts classified as normal purchases and sales and non-derivative contractual commitments that are not recorded on the consolidated balance sheets, except for any related net accounts receivable.

3 The exposure in this category relates to long-term power purchase agreements. SCE's exposure is mitigated by regulatory treatment.

EDISON MISSION GROUP
RESULTS OF OPERATIONS

EMG primarily operates in one line of business, independent power production. The following table is a summary of competitive power generation results of operations for the periods indicated.

	Three months ended March 31,	
(in millions)	2012	2011
Competitive power generation operating revenues	$444	$552
Fuel	206	182
Operation and maintenance	241	281
Depreciation and amortization	68	73
Loss on disposal and asset impairments	14	—
Total operating expenses	529	536
Operating income (loss)	(85)	16
Interest and dividend income	1	2
Equity in loss from unconsolidated affiliates – net	(1)	(5)
Other income (expense), net	—	3
Interest expense	(86)	(80)
Loss from continuing operations before income taxes	(171)	(64)
Income tax benefit	(90)	(46)
Loss from continuing operations	(81)	(18)
Loss from discontinued operations–net of tax	(1)	(2)
Net loss	(82)	(20)
Less: Net income attributable to noncontrolling interests	(2)	—
Net loss available for common stock	$(84)	$(20)
Core Losses[1]	$(60)	$(8)
Non-Core Losses:		
Homer City	(23)	(10)
Discontinued Operations	(1)	(2)
Total EMG GAAP Losses	$(84)	$(20)

[1] See use of Non-GAAP financial measures in "Edison International Overview—Highlights of Operating Results."

EMG's core loss in the first quarter 2012 increased compared to the first quarter 2011 primarily due to the following pre-tax items:

- $95 million decrease in Midwest Generation results primarily due to lower average realized prices, lower capacity prices, higher fuel prices and reduced generation.
- $6 million increase in interest expense due to new energy project financings ($2 million) and lower capitalized interest ($4 million).

The decrease was partially offset by the following pre-tax items:

- $4 million increase in energy trading due to increased revenues from trading power contracts and congestion.
- $9 million increase in renewable energy income due to the increase in wind projects in operation coupled with higher generation and more favorable wind conditions.

50

Adjusted Operating Income (Loss) ("AOI")—Overview

The following table shows the adjusted operating income (loss) (AOI) of EMG's projects:

	Three months ended March 31,	
(in millions)	2012	2011
Midwest Generation plants	$(40)	$55
Homer City plant	(38)	(16)
Renewable energy projects	30	21
Energy trading	19	15
Big 4 projects	(1)	2
Sunrise	—	(7)
Westside projects	(2)	—
Leveraged lease income	1	1
Other projects	2	4
	(29)	75
Corporate administrative and general	(33)	(36)
Corporate depreciation and amortization	(6)	(6)
AOI[1]	$(68)	$33

[1] AOI is equal to operating income (loss) under GAAP, plus equity in income (loss) of unconsolidated affiliates, dividend income from projects, production tax credits, other income and expenses, and net income (loss) attributable to noncontrolling interests. Production tax credits are recognized as wind energy is generated based on a per-kilowatt-hour rate prescribed in applicable federal and state statutes. AOI is a non-GAAP performance measure and may not be comparable to those of other companies. Management believes that inclusion of earnings of unconsolidated affiliates, dividend income from projects, production tax credits, other income and expenses, and net income (loss) attributable to noncontrolling interests in AOI is meaningful for investors as these components are integral to the operating results of EMG.

The following table reconciles AOI to operating income (loss) as reflected on EMG's consolidated statements of operations:

	Three months ended March 31,	
(in millions)	2012	2011
AOI	$(68)	$33
Less:		
Equity in loss of unconsolidated affiliates	(1)	(5)
Dividend income from projects	—	1
Production tax credits	19	18
Other income, net	1	3
Net income attributable to noncontrolling interests	(2)	—
Operating Income (Loss)	$(85)	$16

51

Adjusted Operating Income from Consolidated Operations

Midwest Generation Plants

The following table presents additional data for the Midwest Generation plants:

	Three months ended March 31,	
(in millions)	2012	2011
Operating Revenues	$233	$351
Operating Expenses		
Fuel	117	126
Plant operations	109	118
Plant operating leases	19	19
Depreciation and amortization	21	29
Loss on disposal and asset impairments	2	—
Administrative and general	5	6
Total operating expenses	273	298
Operating Income (Loss)	(40)	53
Other Income	—	2
AOI	$(40)	$55
Statistics		
Generation (in GWh)	5,339	7,470

AOI from the Midwest Generation plants decreased $95 million for the first quarter of 2012 compared to the first quarter of 2011. The 2012 decrease in AOI was primarily attributable to lower average realized energy prices, lower capacity prices, higher fuel prices, and reduced generation. Reduced generation resulted from lower economic dispatch, increased planned maintenance in 2012 versus 2011 and a weather anomaly seen in March of 2012 when unseasonably warm weather increased river temperature to levels that impacted the thermal discharge limits of the Joliet and Will County units.

Included in operating revenues were unrealized gains of $4 million and none for the first quarters of 2012 and 2011, respectively. Unrealized gains in the first quarter of 2012 were primarily attributable to natural gas futures contracts that are accounted for at fair value with offsetting changes recorded on the consolidated statements of operations. Unrealized gains also included the ineffective portion of hedge contracts at the Midwest Generation plants attributable to changes in the difference between energy prices at the Northern Illinois Hub (the settlement point under forward contracts) and the energy prices at the Midwest Generation plants' busbars (the delivery point where power generated by the Midwest Generation plants is delivered into the transmission system) resulting from marginal losses.

Included in fuel costs were unrealized gains (losses) of $3 million and $(1) million during the first quarters of 2012 and 2011, respectively, due to oil futures contracts that were accounted for as economic hedges. These contracts were entered into as hedges of the variable fuel price component of rail transportation costs.

Homer City

The following table presents additional data for the Homer City plant, which is being classified as a non-core earnings item under "Edison International Overview—Highlights of Operating Results":

	Three months ended March 31,	
(in millions)	2012	2011
Operating Revenues	$100	$115
Operating Expenses		
Fuel	84	52
Plant operations	19	47
Plant operating leases	19	25
Depreciation and amortization	—	5
Loss on disposal and asset impairments	11	—
Administrative and general	5	2
Total operating expenses	138	131
Operating Loss	(38)	(16)
AOI	$(38)	$(16)
Statistics		
Generation (in GWh)	2,607	1,943

AOI from the Homer City plant decreased $22 million for the first quarter of 2012 compared to the first quarter of 2011. The 2012 decrease in AOI was primarily attributable to lower energy margins, partially offset by a decline in plant maintenance costs due to outages at Units 1 and 2 during the first quarter of 2011. Lower energy margins were due to lower average realized energy prices and higher coal and emission allowance costs. During the first quarter of 2012, Homer City incurred capital expenditures related to environmental improvements. Those environmental improvements did not increase the fair value of the leasehold interest due to the issues discussed in "Management Overview of EMG"; therefore, the costs were fully impaired. In addition, plant operating lease expense decreased in the first quarter of 2012 compared to the first quarter of 2011 as a result of the impairment of prepaid rent related to the Homer City lease in the fourth quarter of 2011. The impairment resulted in a new levelized rent schedule.

Seasonality—Coal Plants

Due to fluctuations in electric demand resulting from warm weather during the summer months and cold weather during the winter months, electric revenues from the coal plants normally vary substantially on a seasonal basis. In addition, maintenance outages generally are scheduled during periods of lower projected electric demand (spring and fall), further reducing generation and increasing major maintenance costs which are recorded as an expense when incurred. Accordingly, income from the coal plants is seasonal and has significant variability from quarter to quarter. Seasonal fluctuations may also be affected by changes in market prices. For further discussion regarding market prices, see "EMG: Market Risk Exposures—Commodity Price Risk—Energy Price Risk."

Renewable Energy Projects

The following table presents additional data for EMG's renewable energy projects:

	Three months ended March 31,	
(in millions)	2012	2011
Operating Revenues	$72	$52
Production Tax Credits	19	18
	91	70
Operating Expenses		
Plant operations	19	18
Depreciation and amortization	39	31
Administrative and general	2	1
Total operating expenses	60	50
Equity in income from unconsolidated affiliates	1	—
Other Income	—	1
Net Income Attributable to Noncontrolling Interests	(2)	—
AOI[1]	$30	$21
Statistics		
Generation (in GWh)[2]	1,746	1,385

1 AOI is equal to operating income (loss) under GAAP plus equity in income (loss) of unconsolidated affiliates, dividend income from projects, production tax credits, other income and expense, and net (income) loss attributable to noncontrolling interests. Production tax credits are recognized as wind energy is generated based upon a per-kilowatt-hour rate prescribed in applicable federal and state statutes. Under GAAP, production tax credits generated by wind projects are recorded as a reduction in income taxes. Accordingly, AOI represents a non-GAAP performance measure which may not be comparable to those of other companies. Management believes that inclusion of production tax credits in AOI for wind projects is meaningful for investors as federal and state subsidies are an integral part of the economics of these projects.

2 Includes renewable energy projects that are not consolidated by EMG. Generation excluding unconsolidated projects was 1,516 GWh and 1,202 GWh in the first quarter of 2012 and 2011, respectively.

AOI from renewable energy projects increased $9 million in the first quarter of 2012 compared to the first quarter of 2011. The 2012 increase was primarily attributable to projects that achieved commercial operation after the first quarter of 2011 and increased generation at other projects due to more favorable wind conditions during 2012. Net income attributable to noncontrolling interests was primarily due to the Capistrano Wind equity capital transaction. For additional information, see "Edison International Notes to Consolidated Financial Statements—Note 3. Variable Interest Entities—Projects or Entities that are Consolidated—Capistrano Wind Equity Capital."

Energy Trading

AOI from energy trading activities increased $4 million for the first quarter of 2012, compared to the first quarter of 2011 mainly due to higher revenues from power trading activities and congestion.

Adjusted Operating Income from Other Projects

Sunrise Project. AOI from the Sunrise project increased $7 million during the first quarter of 2012 compared to the first quarter of 2011 primarily due to higher repairs and maintenance costs for a major overhaul in 2011.

Seasonality. EMG's third quarter equity in income from its unconsolidated energy projects is normally higher than equity in income related to other quarters of the year due to seasonal fluctuations and higher energy contract prices during the summer months.

Interest Income (Expense)

(in millions)	Three months ended March 31, 2012	2011
Interest income	$—	$1
Interest expense, net of capitalized interest		
EME debt	(67)	(62)
Nonrecourse debt	(19)	(18)
	$(86)	$(80)

EMG's interest expense increased $6 million for the first quarter of 2012 compared to the first quarter of 2011. The 2012 increase in interest expense was primarily due to lower capitalized interest and higher debt balances from new project financings. Capitalized interest was $6 million and $10 million for the first quarters of 2012 and 2011, respectively. The 2012 decrease was due to fewer projects under construction in 2012 compared to 2011.

Income Taxes

The table below provides a reconciliation of income tax benefit computed at the federal statutory income tax rate:

(in millions)	Three months ended March 31, 2012	2011
Loss from continuing operations before income taxes	$(171)	$(64)
Provision for income tax benefit at federal statutory rate of 35%	$(60)	$(22)
Increase (decrease) in income tax from:		
State tax benefit – net of federal tax expense	(14)	(5)
Tax credits, net	(19)	(18)
Property-related	—	(1)
Other	3	—
Total income tax benefit from continuing operations	$(90)	$(46)
Effective tax rate	53%	72%

EMG's effective tax rates were impacted by production tax credits and estimated state income tax benefits allocated from Edison International. Estimated state income tax benefits allocated from Edison International of $3 million and $2 million were recognized for the three months ended March 31, 2012 and 2011, respectively.

55

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

The following table summarizes available liquidity at March 31, 2012:

(in millions)	Cash and Cash Equivalents	Available Under Credit Facility[1]	Total Available Liquidity
EME as a holding company	$711	$—	$711
EME subsidiaries without contractual dividend restrictions	216	—	216
EME corporate cash and cash equivalents	927	—	927
EME subsidiaries with contractual dividend restrictions			
Midwest Generation[2]	230	500	730
Homer City	84	—	84
Other EME subsidiaries	66	—	66
Other EMG subsidiaries	58	—	58
Total	$1,365	$500	$1,865

1 Midwest Generation's existing credit facility matures in June 2012. For further discussion, see "Edison International Overview—Management Overview of EMG" and refer to "Item 1A. Risk Factors—Risks Relating to EMG—Liquidity Risks" in Edison International's annual report on Form 10-K for the year ended December 31, 2011. In the first quarter of 2012, EME terminated its $564 million revolving credit facility and entered into replacement letter of credit facilities secured by cash collateral. For additional information, see "Edison International Notes to Consolidated Financial Statements—Note 5—Debt and Credit Agreements—2012 Letter of Credit Facilities."

2 Cash and cash equivalents are available to meet Midwest Generation's operating and capital expenditure requirements.

See "Edison International Overview" for a discussion of EME's liquidity.

EME, as a holding company, does not directly operate any revenue-producing generation facilities. EME relies on cash distributions and tax payments from its projects and tax benefits received under a tax-allocation agreement with Edison International to meet its obligations, including debt service obligations on long-term debt. The timing and amount of distributions from EME's subsidiaries may be restricted. For further details, including the current restrictions on distributions from the Homer City facility, see "—Dividend Restrictions in Major Financings."

Senior notes in the principal amount of $500 million, which bear interest at 7.50% per annum, are due in June 2013. EME may from time to time, seek to retire or purchase its outstanding debt through cash purchases and/or exchange offers, open market purchases, privately negotiated transactions or otherwise, depending on prevailing market conditions, EME's liquidity requirements, contractual restrictions and other factors.

For information regarding third-party capital obtained in February 2012 to finance the development of a portion of EMG's wind portfolio, see "Edison International Overview—Management Overview of EMG—EMG's Renewable Energy Activities" in the MD&A and "Edison International Notes to Consolidated Financial Statements—Note 3. Variable Interest Entities—Projects or Entities that are Consolidated—Capistrano Wind Equity Capital."

56

Capital Investment Plan

Forecasted capital expenditures through 2014 by EMG's subsidiaries for existing projects and corporate activities are as follows:

(in millions)	April through December 2012	2013	2014
Midwest Generation Plants			
Environmental[1]	$27	$102	$311
Plant capital	12	47	16
Homer City Plant	34	23	14
Walnut Creek Project	179	40	—
Renewable Energy Projects	105	1	2
Other capital	17	19	15
Total	$374	$232	$358

1 For additional information, see "Edison International Overview—Management Overview of EMG—Midwest Generation Environmental Compliance Plans and Costs."

Midwest Generation Capital Expenditures

Midwest Generation plants' projected environmental expenditures would retrofit Powerton Units 5 and 6, Joliet Units 7 and 8 and Will County Units 3 and 4, using dry scrubbing with sodium-based sorbents and upgrading particulate removal systems to comply with CPS requirements for SO_2 emissions and the US EPA's regulation on hazardous air pollutant emissions. Decisions regarding whether or not to proceed with retrofitting any particular remaining units to comply with CPS requirements for SO_2 emissions, including those that have received permits, remain subject to a number of factors, such as market conditions, regulatory and legislative developments, and forecasted commodity prices and capital and operating costs applicable at the time decisions are required or made. Final decisions on whether to install controls, to install particular kinds of controls, and to actually expend capital or continue with the expenditure of capital will be made as required, subject to the requirements of the CPS and other applicable regulations. Furthermore, the timing of commencing capital projects may vary from the amounts set forth in the above table. For additional discussion, see "Edison International Overview—Management Overview of EMG—Midwest Generation Environmental Compliance Plans and Costs."

Plant capital expenditures for Midwest Generation includes capital projects for boiler and turbine controls, major boiler components and electrical systems.

Homer City Capital Expenditures

The capital investment plan set forth above does not include environmental capital expenditures to retrofit the Homer City plant because Homer City does not have the funds for retrofits and will be dependent on external funding. Subject to the availability of capital, plant capital expenditures for Homer City are projected to be $34 million for the remaining nine months of 2012 and $23 million and $14 million in 2013 and 2014, respectively. See "Edison International Overview—Management Overview of EMG—Homer City Lease."

Renewable Energy Projects

At March 31, 2012, EMG's development pipeline of potential wind projects was approximately 1,300 MW. Future development of the wind portfolio is dependent on the availability of third-party capital. To the extent that third-party capital is available, the success of development efforts will depend upon, among other things, obtaining permits and agreements necessary to support an investment.

Historical Segment Cash Flows

The table below sets forth condensed historical cash flow information for EMG.

	Three months ended March 31,	
(in millions)	2012	2011
Operating cash flow from continuing operations	$(96)	$116
Operating cash flow from discontinued operations	(1)	(2)
Net cash provided (used) by operating activities	(97)	114
Net cash provided by financing activities	275	103
Net cash used by investing activities	(174)	(108)
Net increase (decrease) in cash and cash equivalents	$4	$109

Net Cash Provided (Used) by Operating Activities

Net cash used by operating activities from continuing operations decreased $212 million in the first quarter of 2012 compared to the first quarter of 2011 primarily due to decreased operating income due to declining energy prices, increased operating costs and higher interest payments due to new energy project financings.

Net Cash Provided by Financing Activities

Net cash provided by financing activities from continuing operations increased $172 million in the first quarter of 2012 compared to the first quarter of 2011 primarily due to cash contributions from noncontrolling interests and the timing of financings and repayment of debt as summarized in the following table:

	Three months ended March 31,	
(in millions)	2012	2011
Cash contributions from noncontrolling interests	$238	$—
Long-term debt financings		
Renewable energy projects	—	76
Walnut Creek project	54	—
Short-term debt financings		
Renewable energy projects	—	32
Debt repayments		
Renewable energy projects	(4)	(6)
Other projects	(3)	(2)
Financing costs and others	(10)	3
Total cash provided by financing activities	$275	$103

58

Net Cash Used by Investing Activities

Net cash used by investing activities from continuing operations decreased $66 million in the first quarter of 2012 compared to the first quarter of 2011 primarily due to the timing of capital expenditures and cash collateral to secure letter of credit facilities associated with the termination of EME's revolving credit facility. Changes in other investing activities are reflected in the following table:

	Three months ended March 31,	
(in millions)	2012	2011
Capital expenditures		
Midwest Generation plants		
Environmental	$(7)	$(21)
Plant capital	(3)	(10)
Homer City plant	(7)	(4)
Walnut Creek project	(55)	—
Renewable energy projects	(13)	(67)
Other capital expenditures	(1)	(3)
Investments in other assets	(3)	(1)
Collateral for letter of credit facilities	(74)	—
Other investing activities	(11)	(2)
Total cash used in investing activities	$(174)	$(108)

Credit Ratings

Credit ratings for EME, Midwest Generation and EMMT are as follows:

	Moody's Rating	S&P Rating	Fitch Rating
EME[1]	Caa3	CCC+	C
Midwest Generation[2]	B2	B	CCC
EMMT	Not Rated	CCC+	Not Rated

1 Senior unsecured rating.

2 First priority senior secured rating.

All the above ratings are on negative outlook. EMG cannot provide assurance that its current credit ratings or the credit ratings of its subsidiaries will remain in effect for any given period of time or that one or more of these ratings will not be lowered. EMG notes that these credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

EMG does not have any "rating triggers" contained in subsidiary financings that would result in a requirement to make equity contributions or provide additional financial support to its subsidiaries, including EMMT. However, coal contracts at Midwest Generation include provisions that provide the right to request additional collateral to support payment obligations for delivered coal and may vary based on Midwest Generation's credit ratings.

Margin, Collateral Deposits and Other Credit Support for Energy Contracts

Hedging Activities

To reduce its exposure to market risk, EMG hedges a portion of its electricity price exposure through EMMT. In connection with entering into contracts, EMMT may be required to support its risk of nonperformance through parent guarantees, margining or other credit support. EME has entered into guarantees in support of EMMT's hedging and trading activities.

However, EME has historically also provided collateral in the form of cash and letters of credit for the benefit of counterparties. For further details, see "Edison International Notes to Consolidated Financial Statements—Note 6. Derivative Instruments and Hedging Activities."

Future cash collateral requirements may be higher than the margin and collateral requirements at March 31, 2012, if wholesale energy prices change or if EMMT enters into additional transactions. EMG estimates that margin and collateral requirements for energy and congestion contracts outstanding as of March 31, 2012 could increase by approximately $19 million over the remaining life of the contracts using a 95% confidence level.

Debt Covenants and Dividend Restrictions

Key Ratios of EMG's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EMG's principal subsidiaries required by financing arrangements at March 31, 2012 or for the 12 months ended March 31, 2012:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Midwest Generation plants)	Debt-to-Capitalization Ratio	Less than or equal to 0.60 to 1	0.13 to 1
Homer City (Homer City plant)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	1.09 to 1

As indicated above, the actual senior rent service coverage ratio of Homer City was below the covenant threshold for the 12 months ended March 31, 2012, and Homer City also did not meet the threshold for the prospective two 12-month periods, which currently precludes Homer City from making distributions, including repayment of certain intercompany loans and from paying the equity portion of the rent payment. On March 30, 2012, Homer City was granted a waiver by the owner-lessors of any rent default event with respect to the payment of the equity rent for all purposes other than restrictions on distributions from Homer City, including repayment of its intercompany loan . For additional information, see "Edison International Overview—Management Overview of EMG—Homer City Lease."

For a more detailed description of the covenants binding EME's principal subsidiaries that may restrict the ability of those entities to make distributions to EME directly or indirectly through the other holding companies owned by EME, refer to "Edison Mission Group—Liquidity and Capital Resources—Debt Covenants and Dividend Restrictions" in the year-ended 2011 MD&A.

EME's Senior Notes and Guaranty of Powerton-Joliet Leases

EME is restricted under applicable agreements from selling or disposing of assets, which includes distributions, if the aggregate net book value of all such sales and dispositions during the most recent 12-month period would exceed 10% of consolidated net tangible assets as defined in such agreements computed as of the end of the most recent fiscal quarter preceding the sale or disposition in question. At March 31, 2012, the maximum permissible sale or disposition of EME assets was $789 million.

This limitation does not apply if the proceeds are invested in assets in similar or related lines of business of EME. Furthermore, EME may sell or otherwise dispose of assets in excess of such 10% limitation if the proceeds from such sales or dispositions, which are not reinvested as provided above, are retained as cash or cash equivalents or are used to repay debt.

Contractual Obligations and Contingencies

Contingencies

EMG has contingencies related to the Midwest Generation New Source Review lawsuit and other litigation, Homer City New Source Review lawsuit and other litigation, and environmental remediation which are discussed in "Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies."

Off-Balance Sheet Transactions

For a discussion of EMG's off-balance sheet transactions, refer to "EMG: Liquidity and Capital Resources—Off-Balance Sheet Transactions" in the year-ended 2011 MD&A. There have been no significant developments with respect to EMG's off-balance sheet transactions that affect disclosures presented in the 2011 Form 10-K except as set forth in "Edison International Overview—Management Overview of EMG—Homer City Lease."

Environmental Matters and Regulations

For a discussion of EMG's environmental matters, refer to "Environmental Regulation of Edison International and Subsidiaries" in Item 1 of Edison International's 2011 Form 10-K. There have been no significant developments with respect to environmental matters specifically affecting EMG since the filing of the 2011 Form 10-K, except as set forth in "Edison International Notes to Consolidated Financial Statements—Note 10. Environmental Developments."

MARKET RISK EXPOSURES

For a detailed discussion of EMG's market risk exposures, including commodity price risk, credit risk and interest rate risk, refer to "EMG: Market Risk Exposures" in the year ended 2011 MD&A.

Derivative Instruments

Unrealized Gains and Losses

EMG classifies unrealized gains and losses from derivative instruments (other than the effective portion of derivatives that qualify for hedge accounting) as part of operating revenues or fuel costs. The following table summarizes unrealized gains (losses) from non-trading activities:

	Three months ended March 31,	
(in millions)	2012	2011
Midwest Generation plants		
Non-qualifying hedges	$6	$(1)
Ineffective portion of cash flow hedges	1	—
Homer City plant		
Non-qualifying hedges	—	1
Ineffective portion of cash flow hedges	—	1
Total unrealized gains	$7	$1

At March 31, 2012, cumulative unrealized gains of $14 million were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to subsequent periods ($13 million for the remainder of 2012 and $1 million for 2013).

Fair Value Disclosures

In determining the fair value of EMG's derivative positions, EMG uses third-party market pricing where available. For further explanation of the fair value hierarchy and a discussion of EMG's derivative instruments, see "Edison International Notes to Consolidated Financial Statements—Note 4. Fair Value Measurements" and "—Note 6. Derivative Instruments and Hedging Activities," respectively.

Commodity Price Risk

Energy Price Risk

Energy and capacity from the coal plants are sold under terms, including price, duration and quantity, arranged by EMMT with customers through a combination of bilateral agreements (resulting from negotiations or from auctions), forward energy sales and spot market sales. Power is sold into PJM at spot prices based upon locational marginal pricing. Energy from 428 MW of merchant renewable energy projects is sold in the energy markets, primarily at spot prices in PJM and ERCOT.

The following table depicts the average historical market prices for energy per megawatt-hour at the locations indicated for the first quarters of 2012 and 2011:

	24-Hour Average Historical Market Prices[1]	
	2012	2011
Midwest Generation plants		
Northern Illinois Hub	$27.20	$34.01
Homer City plant		
PJM West Hub	$31.82	$46.48
Homer City Busbar	29.01	41.12

1 Energy prices were calculated at the Northern Illinois Hub and Homer City Busbar delivery points and the PJM West Hub using historical hourly day-ahead prices as published by PJM or provided on the PJM web-site.

The following table sets forth the forward market prices for energy per megawatt-hour as quoted for sales into the Northern Illinois Hub and PJM West Hub at March 31, 2012:

	24-Hour Forward Energy Prices[1]	
	Northern Illinois Hub	PJM West Hub
2012		
April	$23.05	$28.65
May	23.38	28.90
June	25.44	32.19
July	29.99	36.55
August	30.61	37.28
September	23.22	30.35
October	22.84	29.83
November	23.16	30.82
December	26.54	35.37
2013 calendar "strip"[2]	$29.64	$37.44

1 Energy prices were determined by obtaining broker quotes and information from other public sources relating to the Northern Illinois Hub and PJM West Hub delivery points.

2 Market price for energy purchases for the entire calendar year.

Power prices continued to fall in the first quarter of 2012 due to an abundance of low-priced natural gas and the sales volume from the Midwest Generation plants has been correspondingly affected. Forward market prices at the Northern Illinois Hub and PJM West Hub fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand (which in turn is affected by weather, economic growth, and other factors), plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered by the coal plants into these markets may vary materially from the forward market prices set forth in the preceding table.

EMMT engages in hedging activities for the coal plants to hedge the risk of future change in the price of electricity. The following table summarizes the hedge positions (including load requirements services contracts) at March 31, 2012 for electricity expected to be generated during the remainder of 2012 and in 2013:

	2012		2013	
	MWh (in thousands)	Average price/ MWh[1]	MWh (in thousands)	Average price/ MWh[1]
Midwest Generation plants[2]	4,719	$39.18	1,020	$40.43
Homer City plant[3,4]	112	54.12	—	—
Total	4,831		1,020	

1 The above hedge positions include forward contracts for the sale of power and futures contracts during different periods of the year and the day. Market prices tend to be higher during on-peak periods and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge positions are not directly comparable to the 24-hour Northern Illinois Hub or PJM West Hub prices set forth above.

2 Includes hedging transactions primarily at the Northern Illinois Hub and to a lesser extent the AEP/Dayton Hub, both in PJM, and the Indiana Hub in MISO.

3 2012 includes hedging activities entered into by EMMT for the Homer City plant at the PJM APS Zone that are not designated under the intercompany agreements with Homer City due to limitations under the sale-leaseback transaction documents.

4 The average price/MWh includes 158 MW of capacity for periods ranging from April 1, 2012 to May 31, 2012 at Homer City sold in conjunction with load requirements services contracts.

63

Capacity Price Risk

Under the RPM, capacity commitments are made in advance to provide a long-term pricing signal for construction of capacity resources. The following table summarizes the status of capacity sales for Midwest Generation and Homer City at March 31, 2012:

				RPM Capacity Sold in Base Residual Auction		Other Capacity Sales, Net of Purchases[3]		Aggregate Average
	Installed Capacity MW	Unsold Capacity[1] MW	Capacity Sold[2] MW	MW	Price per MW-day	MW	Average Price per MW-day	Price per MW-day
April 1, 2012 to May 31, 2012								
Midwest Generation	5,477	(555)	4,922	4,582	$110.00	340	$98.92	$109.23
Homer City	1,884	(163)	1,721	1,771	110.00	(50)	30.00	112.32
June 1, 2012 to May 31, 2013								
Midwest Generation	5,477	(773)	4,704	4,704	16.46	—	—	16.46
Homer City	1,884	(355)	1,529	1,736	133.37	(207)	8.16	150.35
June 1, 2013 to May 31, 2014								
Midwest Generation	5,477	(827)	4,650	4,650	27.73	—	—	27.73
Homer City	1,884	(104)	1,780	1,780	226.15	—	—	221.03[4]
June 1, 2014 to May 31, 2015								
Midwest Generation	5,477	(852)	4,625	4,625	125.99	—	—	125.99
Homer City	1,884	(190)	1,694	1,694	136.50	—	—	136.50

1 Capacity not sold arises from: (i) capacity retained to meet forced outages under the RPM auction guidelines, and (ii) capacity that PJM does not purchase at the clearing price resulting from the RPM auction.

2 Excludes 158 MW of capacity for periods ranging from April 1, 2012 to May 31, 2012 at Homer City sold in conjunction with load requirements services contracts.

3 Other capacity sales and purchases, net includes contracts executed in advance of the RPM base residual auction to hedge the price risk related to such auction, participation in RPM incremental auctions and other capacity transactions entered into to manage capacity risks.

4 Includes the impact of a 100 MW capacity swap transaction executed prior to the base residual auction at $135 per MW-day.

The RPM auction capacity prices for the delivery period of June 1, 2012 to May 31, 2013 and June 1, 2013 to May 31, 2014 varied between different areas of PJM. In the western portion of PJM, affecting Midwest Generation, the prices of $16.46 per MW-day and $27.73 per MW-day were substantially lower than other areas' capacity prices. The impact of lower capacity prices for these periods compared to previous years will have an adverse effect on Midwest Generation's revenues unless such lower capacity prices are offset by an unavailability of competing resources and increased energy prices.

Revenues from the sale of capacity from Midwest Generation and Homer City beyond the periods set forth above will depend upon the amount of capacity available and future market prices either in PJM or nearby markets if those facilities have an opportunity to capture a higher value associated with those markets.

Effective April 16, 2012, EMMT assigned the awards it received related to Homer City capacity to Homer City effective as of June 1, 2012. As a result of the financial outlook of Homer City, as previously discussed, EME's subsidiary, EMMT, has ceased to enter into hedging activities related to future power sales, but continues to enter into short-term energy transactions on behalf of Homer City pursuant to an intercompany agreement. Those transactions are generally back-to-back transactions in which EMMT enters into a transaction with a third party as a principal and then enters into an equivalent transaction with Homer City.

Basis Risk

During the three months ended March 31, 2012 and 2011, day-ahead prices at the Homer City busbar were lower than those at the PJM West Hub by an average of 9% and 12%, respectively. During the three months ended March 31, 2012, day-ahead prices at the individual busbars of the Midwest Generation plants compared to the AEP/Dayton Hub, Indiana Hub (Cinergy

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Hub) and Northern Illinois Hub were on average lower by 6%, higher by 3% and higher by 1%, respectively. During the three months ended March 31, 2011, day-ahead prices at the individual busbars of the Midwest Generation plants were lower compared to the AEP/Dayton Hub, Indiana Hub (Cinergy Hub) and Northern Illinois Hub by an average of 11%, 6% and 1%, respectively. Differences in day-ahead pricing between the individual busbars of the Homer City and Midwest Generation plants generally arise due to transmission congestion.

Credit Risk

The credit risk exposure from counterparties of merchant energy hedging and trading activities is measured as the sum of net receivables (accounts receivable less accounts payable) and the current fair value of net derivative assets. EMG's subsidiaries enter into master agreements and other arrangements in conducting such activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. At March 31, 2012, the balance sheet exposure as described above, by the credit ratings of EMG's counterparties, was as follows:

	March 31, 2012		
(in millions)	Exposure[2]	Collateral	Net Exposure
Credit Rating[1]			
A or higher	$81	$(8)	$73
A-	3	—	3
BBB+	1	—	1
BBB-	4	—	4
Below investment grade	78	(77)	1
Total	$167	$(85)	$82

1 EMG assigns a credit rating based on the lower of a counterparty's S&P or Moody's rating. For ease of reference, the above table uses the S&P classifications to summarize risk, but reflects the lower of the two credit ratings.

2 Exposure excludes amounts related to contracts classified as normal purchase and sales and non-derivative contractual commitments that are not recorded on the consolidated balance sheet, except for any related accounts receivable.

The credit risk exposure set forth in the above table is composed of $50 million of net accounts receivable and payables and $117 million representing the fair value of derivative contracts. The exposure is based on master netting agreements with the related counterparties. Credit ratings may not be reflective of the actual related credit risks. In addition to the amounts set forth in the above table, EMG's subsidiaries have posted a $76 million cash margin in the aggregate with PJM, NYISO, MISO, clearing brokers and other counterparties to support hedging and trading activities. The margin posted to support these activities also exposes EMG to credit risk of the related entities.

The coal plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transacting in capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 67% of EMG's consolidated operating revenues for the three months ended March 31, 2012. At March 31, 2012, EMG's account receivable due from PJM was $41 million.

EMG's wind turbine supply agreements contain significant suppliers' obligations related to the manufacturing and delivery of turbines, and payments, for delays in delivery and for failure to meet performance obligations and warranty agreements. EMG's reliance on these contractual provisions is subject to credit risks. Generally, these are unsecured obligations of the turbine manufacturer. A material adverse development with respect to EMG's turbine suppliers may have a material impact on EMG's wind projects and development efforts.

Interest Rate Risk

Interest rate changes can affect earnings and the cost of capital for capital improvements or new investments in power projects. EMG mitigates the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of its project financings. For further details, see "Edison International Notes to Consolidated Financial Statements—Note 5. Debt and Credit Agreements" and "—Note 6. Derivative Instruments and Hedging Activities."

EDISON INTERNATIONAL PARENT AND OTHER

RESULTS OF OPERATIONS

Results of operations for Edison International Parent and Other includes amounts from other Edison International subsidiaries that are not significant as a reportable segment, as well as intercompany eliminations.

Edison International Parent and Other loss from continuing operations was $5 million and $2 million for the three months ended March 31, 2012 and 2011, respectively. Results included consolidated tax benefits of $4 million and $6 million in 2012 and 2011, respectively, representing differences in the allocation of state income taxes to subsidiaries under tax allocation agreements.

LIQUIDITY AND CAPITAL RESOURCES

Edison International Parent liquidity and its ability to pay operating expenses and dividends to common shareholders is dependent on dividends from SCE, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to bank and capital markets.

The following table summarizes the status of the Edison International Parent credit facility (expires in February 2013) at March 31, 2012:

(in millions)	Edison International (parent)
Commitment	$1,379
Outstanding borrowings	(13)
Outstanding letters of credit	—
Amount available	$1,366

Edison International expects to complete negotiations for a replacement credit facility with substantially similar terms and current market rates in 2012.

Edison International has a debt covenant in its credit facility that requires a consolidated debt to total capitalization ratio of less than or equal to 0.65 to 1. At March 31, 2012, Edison International's consolidated debt to total capitalization ratio was 0.56 to 1.

Historical Segment Cash Flows

The table below sets forth condensed historical cash flow information for Edison International Parent and Other.

	Three months ended March 31,	
(in millions)	2012	2011
Net cash used by operating activities	$(2)	$(69)
Net cash provided by financing activities	6	72
Net cash provided by investing activities	—	—
Net increase in cash and cash equivalents	$4	$3

Net Cash Used by Operating Activities

Net cash used by operating activities primarily relate to interest, operating costs and income taxes of Edison International Parent. In addition to these factors, Edison International Parent funded a portion of the 2011 tax-allocation payments due by Edison Capital in consideration of an intercompany note receivable.

66

Net Cash Provided by Financing Activities

Financing activities for the first quarter of 2012 were as follows:

- Paid $106 million of dividends to Edison International common shareholders.
- Received $116 million of dividend payments from SCE.

Financing activities for the first quarter of 2011 were as follows:

- Paid $104 million of dividends to Edison International common shareholders.
- Received $115 million of dividend payments from SCE.
- Borrowed $62 million under Edison International's line of credit to fund interim working capital requirements.

67

EDISON INTERNATIONAL (CONSOLIDATED)

LIQUIDITY AND CAPITAL RESOURCES

Contractual Obligations

Significant changes with respect to Edison International (Consolidated) contractual obligations since the filing of the 2011 Form 10-K are discussed in "EMG: Liquidity and Capital Resources—Contractual Obligations and Contingencies" and "SCE: Liquidity and Capital Resources—Contractual Obligations and Contingencies."

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

For a discussion of Edison International's critical accounting estimates and policies, see "Critical Accounting Estimates and Policies" in the year-ended 2011 MD&A.

NEW ACCOUNTING GUIDANCE

New accounting guidance is discussed in "Edison International Notes to Consolidated Financial Statements—Note 1. Summary of Significant Accounting Policies—New Accounting Guidance."

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information responding to Item 3 is included in the MD&A under the headings "SCE: Market Risk Exposures" and "EMG: Market Risk Exposures."

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Edison International's management, under the supervision and with the participation of the company's Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of Edison International's disclosure controls and procedures (as that term is defined in Rules 13a-15(e) or 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of the end of the period, Edison International's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

There were no changes in Edison International’s internal control over financial reporting (as that term is defined in Rules 13a-15(f) or 15d-15(f) under the Exchange Act) during the period to which this report relates that have materially affected, or are reasonably likely to materially affect, Edison International’s internal control over financial reporting.

Jointly Owned Utility Plant

Edison International's scope of evaluation of internal control over financial reporting includes its Jointly Owned Utility Projects.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For a discussion of Edison International's legal proceedings, refer to "Edison International Notes to Consolidated Financial Statements—Note 9. Commitments and Contingencies—Contingencies" in the 2011 Form 10-K. There have been no significant developments with respect to legal proceedings specifically affecting Edison International since the filing of the 2011 Form 10-K, except as follows:

Midwest Generation New Source Review and Other Litigation

In February 2012, certain of the environmental action groups that had intervened in the US EPA's New Source Review case entered into an agreement with Midwest Generation to dismiss without prejudice all of their opacity claims as to all defendants. The agreed upon motion to dismiss was approved by the court on March 26, 2012.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table contains information about all purchases of Edison International Common Stock made by or on behalf of Edison International in the first quarter of 2012.

Period	(a) Total Number of Shares (or Units) Purchased[1]	(b) Average Price Paid per Share (or Unit)[1]	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
January 1, 2012 to January 31, 2012	737,675	$40.90	—	—
February 1, 2012 to February 29, 2012	484,676	$41.31	—	—
March 1, 2012 to March 31, 2012	1,031,072	$42.83	—	—
Total	2,253,423	$41.87	—	—

[1] The shares were purchased by agents acting on Edison International's behalf for delivery to plan participants to fulfill requirements in connection with Edison International's: (i) 401(k) Savings Plan; (ii) Dividend Reinvestment and Direct Stock Purchase Plan; and (iii) long-term incentive compensation plans. The shares were purchased in open-market transactions pursuant to plan terms or participant elections. The shares were never registered in Edison International's name and none of the shares purchased were retired as a result of the transactions.

69

ITEM 6. EXHIBITS

Exhibit Number	Description
10.1**	Edison International 2012 Executive Annual Incentive Program
10.2**	Edison International 2012 Long-Term Incentives Terms and Conditions
10.3**	Edison International Executive Incentive Compensation Plan, as amended and restated effective January 1, 2012
31.1	Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act
31.2	Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act
32	Statement Pursuant to 18 U.S.C. Section 1350
101	Financial statements from the quarterly report on Form 10-Q of Edison International for the quarter ended March 31, 2012, filed on May 2, 2012, formatted in XBRL: (i) the Consolidated Statements of Income; (ii) the Consolidated Statements of Comprehensive Income; (iii) the Consolidated Balance Sheets; (iv) the Consolidated Statements of Cash Flows; and (v) the Notes to Consolidated Financial Statements

** Indicates a management contract or compensatory plan or arrangement, as required by Item 15(a)3.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EDISON INTERNATIONAL

By: /s/ Mark C. Clarke

Mark C. Clarke
Vice President and Controller
(Duly Authorized Officer and
Principal Accounting Officer)

Date: May 2, 2012