TECO ENERGY INC
Form 10-K
February 27, 2015

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2014

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 No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	TECO ENERGY, INC. (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-2052286
1-5007	TAMPA ELECTRIC COMPANY (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	59-0475140

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc.	
Common Stock, $1.00 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if TECO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

YES x NO ¨

Indicate by check mark if Tampa Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

YES ¨ NO x

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

YES ¨ NO x

Indicate by check mark whether the registrants (1) have 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) have been subject to such filing requirements for the past 90 days.

YES x NO ¨

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

YES x NO ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether TECO Energy, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	x	Accelerated filer	¨
Non-accelerated filer	¨	Smaller reporting company	¨

Indicate by check mark whether Tampa Electric Company is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	x	Smaller reporting company	¨

Indicate by check mark whether TECO Energy, Inc. is a shell company (as defined in Rule 12b-2 of the Act).

YES ¨ NO x

Indicate by check mark whether Tampa Electric Company is a shell company (as defined in Rule 12b-2 of the Act).

YES ¨ NO x

The aggregate market value of TECO Energy, Inc.'s common stock held by non-affiliates of the registrant as of June 30, 2014 was approximately $3.97 billion based on the closing sale price as reported on the New York Stock Exchange.

The aggregate market value of Tampa Electric Company's common stock held by non-affiliates of the registrant as of June 30, 2014 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 13, 2015 was 235,528,791. As of Feb. 13, 2015, there were 10 shares of Tampa Electric Company's common stock issued and outstanding, all of which were held, beneficially and of record, by TECO Energy, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement relating to the 2015 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

Tampa Electric Company meets the conditions set forth in General Instruction (I) (1) (a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format.

This combined Form 10-K represents separate filings by TECO Energy, Inc. and Tampa Electric Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Tampa Electric Company makes no representations as to the information relating to TECO Energy, Inc.'s other operations.

DEFINITIONS

Acronyms and defined terms used in this and other filings with the U.S. Securities and Exchange Commission include the following:

Term	Meaning
ABS	asset-backed security
ADR	American depository receipt
AFUDC	allowance for funds used during construction
AFUDC-debt	debt component of allowance for funds used during construction
AFUDC-equity	equity component of allowance for funds used during construction
AMT	alternative minimum tax
AOCI	accumulated other comprehensive income
APBO	accumulated postretirement benefit obligation
ARO	asset retirement obligation
BACT	Best Available Control Technology
BTU	British Thermal Unit
CAA	Federal Clean Air Act
CAIR	Clean Air Interstate Rule
capacity clause	capacity cost-recovery clause, as established by the FPSC
CCRs	coal combustion residuals
CES	Continental Energy Systems
CGESJ	Central Generadora Eléctrica San José, Limitada, owner of the San José Power Station in Guatemala
CMO	collateralized mortgage obligation
CNG	compressed natural gas
company	TECO Energy, Inc.
CPI	consumer price index
CSAPR	Cross State Air Pollution Rule
CO_2	carbon dioxide
CT	combustion turbine
DR-CAFTA	Dominican Republic Central America – United States Free Trade Agreement
ECRC	environmental cost recovery clause
EEGSA	Empresa Eléctrica de Guatemala, S.A.
EEI	Edison Electric Institute
EGWP	Employee Group Waiver Plan
EPA	U.S. Environmental Protection Agency
EPS	earnings per share
ERISA	Employee Retirement Income Security Act
EROA	expected return on plan assets
ERP	enterprise resource planning
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company
FPSC	Florida Public Service Commission
fuel clause	fuel and purchased power cost-recovery clause, as established by the FPSC
GAAP	generally accepted accounting principles
GCBF	gas cost billing factor
GHG	greenhouse gas(es)

HAFTA	Highway and Transportation Funding Act
HCIDA	Hillsborough County Industrial Development Authority
HPP	Hardee Power Partners
IASB	International Accounting Standards Board
ICSID	International Centre for the Settlement of Investment Disputes
IGCC	integrated gasification combined-cycle
IOU	investor owned utility
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association
ITCs	investment tax credits
KW	Kilowatt(s)
KWH	kilowatt-hour(s)
LIBOR	London Interbank Offered Rate

Term	Meaning
MAP-21	Moving Ahead for Progress in the 21st Century Act
MBS	mortgage-backed securities
MD&A	the section of this report entitled Management’s Discussion and Analysis of Financial Condition and Results of Operations
Met	metallurgical
MMA	The Medicare Prescription Drug, Improvement and Modernization Act of 2003
MMBTU	one million British Thermal Units
MRV	market-related value
MSHA	Mine Safety and Health Administration
MW	megawatt(s)
MWH	megawatt-hour(s)
NAESB	North American Energy Standards Board
NAV	net asset value
NMGC	New Mexico Gas Company, Inc.
NMGI	New Mexico Gas Intermediate, Inc.
NMPRC	New Mexico Public Regulation Commission
NOL	net operating loss
Note	Note to consolidated financial statements
NO_x	nitrogen oxide
NPNS	normal purchase normal sale
NYMEX	New York Mercantile Exchange
O&M expenses	operations and maintenance expenses
OCI	other comprehensive income
OPEB	other postretirement benefits
OTC	over-the-counter
PBGC	Pension Benefit Guarantee Corporation
PBO	postretirement benefit obligation
PCI	pulverized coal injection
PCIDA	Polk County Industrial Development Authority
PGA	purchased gas adjustment
PGAC	purchased gas adjustment clause
PGS	Peoples Gas System, the gas division of Tampa Electric Company
PM	particulate matter
PPA	power purchase agreement
PPSA	Power Plant Siting Act
PRP	potentially responsible party
PUHCA 2005	Public Utility Holding Company Act of 2005
REIT	real estate investment trust
RFP	request for proposal
ROE	return on common equity
Regulatory ROE	return on common equity as determined for regulatory purposes
RPS	renewable portfolio standards
ROW	rights-of-way
S&P	Standard and Poor’s
SCR	selective catalytic reduction
SEC	U.S. Securities and Exchange Commission
SO_2	sulfur dioxide
SERP	Supplemental Executive Retirement Plan
SPA	stock purchase agreement

STIF	short-term investment fund
Tampa Electric	Tampa Electric, the electric division of Tampa Electric Company
TCAE	Tampa Centro Americana de Electridad, Limitada, majority owner of the Alborada Power Station
TEC	Tampa Electric Company, the principal subsidiary of TECO Energy, Inc.
TECO Coal	TECO Coal LLC, and its subsidiaries, a coal producing subsidiary of TECO Diversified
TECO Diversified	TECO Diversified, Inc., a subsidiary of TECO Energy, Inc. and parent of TECO Coal Corporation
TECO Energy	TECO Energy, Inc.
TECO Finance	TECO Finance, Inc., a financing subsidiary for the unregulated businesses of TECO Energy, Inc.
TECO Guatemala	TECO Guatemala, Inc., a subsidiary of TECO Energy, Inc., parent company of formerly owned generating and transmission assets in Guatemala.
TGH	TECO Guatemala Holdings, LLC

Term	Meaning
TRC	TEC Receivables Company
USACE	U.S. Army Corps of Engineers
VIE	variable interest entity
WRERA	The Worker, Retiree and Employer Recovery Act of 2008

PART I

Item 1. BUSINESS.

TECO ENERGY

TECO Energy, Inc. was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of Tampa Electric Company. TECO Energy and its subsidiaries had approximately 4,400 employees as of Dec. 31, 2014.

TECO Energy's Corporate Governance Guidelines, the charter of each committee of the Board of Directors, and the code of ethics applicable to all directors, officers and employees, the Code of Ethics and Business Conduct, are available on the Investors section of TECO Energy's website, www.tecoenergy.com, or in print free of charge to any investor who requests the information. TECO Energy also makes its SEC (www.sec.gov) filings available free of charge on the Investors section of TECO Energy's website as soon as reasonably practicable after they are filed with or furnished to the SEC. The public may read and copy any reports or other information that the company files with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

TECO Energy is a holding company for regulated utilities and other businesses. TECO Energy currently owns no operating assets but holds all of the common stock of TEC and, through its subsidiaries, NMGI and TECO Diversified, owns NMGC and TECO Coal, respectively.

Unless otherwise indicated by the context, "TECO Energy" or the "company" means the holding company, TECO Energy, Inc. and its subsidiaries, and references to individual subsidiaries of TECO Energy, Inc. refer to that company and its respective subsidiaries. TECO Energy's business segments and revenues for those segments, for the years indicated, are identified below.

TEC, a Florida corporation and TECO Energy's largest subsidiary, has two business segments. Its Tampa Electric division provides retail electric service to more than 706,000 customers in West Central Florida with a net winter system generating capacity of 4,668 MW. PGS, the gas division of TEC, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With almost 354,000 customers, PGS has operations in Florida's major metropolitan areas. Annual natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) in 2014 was almost 1.5 billion therms.

NMGC, a Delaware corporation and wholly owned subsidiary of NMGI, was acquired by the company on Sept. 2, 2014. NMGC is engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in New Mexico. With approximately 513,000 customers, NMGC serves approximately 60% of the state's population in 23 of New Mexico's 33 counties. NMGC's largest concentration of customers (approximately 357,000) is in the region known as the Central Rio Grande Corridor, which includes the communities of Albuquerque, Belen, Rio Rancho and Santa Fe. NMGC's results are included as of the acquisition date (see Note 21 to the TECO Energy Consolidated Financial Statements for additional information).

TECO Coal, a Kentucky LLC and wholly owned subsidiary of TECO Diversified, has 10 subsidiaries located in Eastern Kentucky, Tennessee and Virginia. These entities own mineral rights, own or operate surface and underground mines and own interests in coal processing and loading facilities. On Oct. 17, 2014, TECO Diversified entered into an agreement to sell all of its ownership interest in TECO Coal. On Feb. 5, 2015, the agreement was amended to reduce the selling price and extend the closing date to Mar. 13, 2015.

Revenues from Continuing Operations

(millions)	2014	2013	2012
Tampa Electric	$2,021.0	$1,950.5	$1,981.3
PGS	399.6	393.5	398.9
NMGC	137.5	0.0	0.0
Total regulated businesses	2,558.1	2,344.0	2,380.2
Other	8.3	11.1	7.5
Total revenues from continuing operations	$2,566.4	$2,355.1	$2,387.7

For additional financial information regarding TECO Energy’s significant business segments including geographic areas, see Note 14 to the TECO Energy Consolidated Financial Statements.

Discontinued Operations/Asset Dispositions

TECO Guatemala, a Florida corporation, owned subsidiaries that participated in two contracted Guatemalan power plants, Alborada and San José. TECO Energy, Inc. completed the sale of its generating and transmission assets in Guatemala during 2012 as part of a business strategy to focus on its domestic electric and gas utilities.

On Oct. 17, 2014, TECO Diversified entered into an agreement to sell all of its ownership interest in TECO Coal. On Feb. 5, 2015, the agreement was amended to extend the closing date to Mar. 13, 2015 and to establish a purchase price of $80 million plus any cash on hand as of the closing, subject to customary post-closing adjustments, plus contingent payments of up to $60 million that may be paid between 2015 and 2019 depending on specified coal benchmark prices.

See Notes 19, 20 and 23 to the TECO Energy, Inc. Consolidated Financial Statements for more information regarding these discontinued operations and asset dispositions.

Acquisition of NMGI

On Sept. 2, 2014, the company completed the acquisition contemplated by the SPA dated May 25, 2013 by and among the company, NMGI and Continental Energy Systems LLC. As a result of that acquisition, the company acquired all of the capital stock of NMGI. NMGI, which was incorporated in the State of Delaware in 2008, is the parent company of NMGC. The aggregate purchase price was $950 million, which included the assumption of $200 million of senior secured notes at NMGC, plus certain working capital adjustments.

See Note 21 to the TECO Energy, Inc. Consolidated Financial Statements for more information regarding the acquisition.

TAMPA ELECTRIC – Electric Operations

TEC was incorporated in Florida in 1899 and was reincorporated in 1949. TEC is a public utility operating within the State of Florida. Its Tampa Electric division is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The retail territory served comprises an area of about 2,000 square miles in West Central Florida, including Hillsborough County and parts of Polk, Pasco and Pinellas Counties, with an estimated population of over one million. The principal communities served are Tampa, Temple Terrace, Winter Haven, Plant City and Dade City. In addition, Tampa Electric engages in wholesale sales to utilities and other resellers of electricity. It has three electric generating stations in or near Tampa, one electric generating station in southwestern Polk County, Florida and one electric generating station in long-term reserve standby located near Sebring, a city in Highlands County in South Central Florida.

Tampa Electric had 2,370 employees as of Dec. 31, 2014, of which 877 were represented by the International Brotherhood of Electrical Workers and 169 were represented by the Office and Professional Employees International Union. In January 2015, 290 Tampa Electric employees were transferred to TECO Energy's centralized service company subsidiary, TECO Services, Inc.

In 2014, Tampa Electric's total operating revenue was derived approximately 50% from residential sales, 30% from commercial sales, 8% from industrial sales and 12% from other sales, including bulk power sales for resale. Approximately 4% of revenues were attributable to governmental municipalities. The sources of operating revenue and MWH sales for the years indicated were as follows:

Operating Revenue

(millions)	2014	2013	2012
Residential	$1,007.6	$936.8	$958.9
Commercial	602.0	581.2	612.3
Industrial – Phosphate	59.9	71.9	75.7
Industrial – Other	104.6	100.4	101.2
Other retail sales of electricity	181.9	177.4	184.0
Total retail	1,956.0	1,867.7	1,932.1
Sales for resale	13.0	8.5	16.2
Other	52.0	74.3	33.0
Total operating revenues	$2,021.0	$1,950.5	$1,981.3

Megawatt- hour Sales

(thousands)	2014	2013	2012
Residential	8,656	8,470	8,395
Commercial	6,142	6,090	6,185
Industrial	1,901	2,026	2,002
Other retail sales of electricity	1,827	1,832	1,827
Total retail	18,526	18,418	18,409
Sales for resale	259	222	267
Total energy sold	18,785	18,640	18,676

No significant part of Tampa Electric's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on Tampa Electric. Tampa Electric's business is not highly seasonal, but winter peak loads are experienced due to electric space heating, fewer daylight hours and colder temperatures and summer peak loads are experienced due to the use of air conditioning and other cooling equipment.

Regulation

Tampa Electric's retail operations are regulated by the FPSC, which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices and other matters.

In general, the FPSC's pricing objective is to set rates at a level that provides an opportunity for the utility to collect total revenues (revenue requirements) equal to its cost to provide service, plus a reasonable return on invested capital.

The costs of owning, operating and maintaining the utility systems, excluding fuel and conservation costs as well as purchased power and certain environmental costs for the electric system, are recovered through base rates. These costs include O&M expenses, depreciation and taxes, as well as a return on investment in assets used and useful in providing electric service (rate base). The rate of return on rate base, which is intended to approximate the individual company's weighted cost of capital, primarily includes its costs for debt, deferred income taxes (at a zero cost rate) and an allowed ROE. Base rates are determined in FPSC revenue requirement and rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, the FPSC or other interested parties.

Tampa Electric's results for 2014 and the last two months of 2013 reflect the results of a Stipulation and Settlement Agreement entered on Sept. 6, 2013, between TEC and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric's 2013 base rate proceeding. On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement.

This agreement provided for the following revenue increases: $57.5 million effective Nov. 1, 2013, an additional $7.5 million effective Nov. 1, 2014, an additional $5.0 million effective Nov. 1, 2015, and an additional $110.0 million effective Jan. 1, 2017 or the date that an expansion of TEC's Polk Power Station goes into service, whichever is later. The agreement provides that Tampa Electric's allowed regulatory ROE would be a mid-point of 10.25% with a range of plus or minus 1%, with a potential increase to 10.50% if U.S. Treasury bond yields exceed a specified threshold. The agreement provides that Tampa Electric cannot file for additional rate increases until 2017 (to be effective no sooner than Jan. 1, 2018), unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE is increased as described above) any party to the agreement other than TEC could seek a review of Tampa Electric's base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital, and Tampa Electric also began using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013. Effective Nov. 1, 2013, Tampa Electric ceased accruing $8.0 million annually to the FERC-authorized and

FPSC-approved self-insured storm damage reserve.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services and accounting practices.

Non-power goods and services transactions between Tampa Electric and its affiliates are subject to regulation by the FPSC and FERC, and any charges deemed to be imprudently incurred may be disallowed for recovery from Tampa Electric's retail and wholesale customers. Given TECO Energy's acquisition of NMGC on Sept. 2, 2014, Tampa Electric and TECO Energy jointly requested a waiver from FERC on Oct. 1, 2014 in order for Tampa Electric to continue to supply a de-minimis level of non-power goods and services to its affiliates as of Jan. 1, 2015. On Oct. 1, TECO Energy separately notified FERC that it would no longer qualify to be considered a single-state holding company under the Public Utility Holding Company Act of 2005 as of Jan. 1, 2015, and thus it had formed a centralized service company, TECO Services, Inc., which would provide other non-power goods and services to Tampa Electric and its affiliates. On Dec. 31, 2014, FERC granted Tampa Electric's requested waiver without conditions, effective as of Jan. 1, 2015.

In 2012, Tampa Electric received notification from the FERC that its accounting practices and financial reporting processes would be audited, along with its compliance with the FERC's records retention requirements. No material issues were identified as a result of the audit, and the audit was concluded during 2014, with the identification of four non-material items. Tampa Electric updated certain accounting processes and refunded de-minimis amounts to its transmission customers during 2014 as a result of this audit.

On June 30, 2014, the company filed its required triennial market-power analysis, demonstrating that the company does not have wholesale market power using FERC's two analytical screens. This compliance filing was made in support of the company's continued ability to effect wholesale market-based rate transactions everywhere, except within Tampa Electric's balancing-authority area. FERC is expected to respond to Tampa Electric's triennial filing during the first half of 2015.

Tampa Electric is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters (see the Environmental Compliance section of the MD&A).

Competition

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Distributed generation could also be a source of competition in the future, but has not been a significant factor to date (see the Environmental Compliance section of the MD&A). Tampa Electric intends to retain and expand its retail business by managing costs and providing quality service to retail customers.

Unlike the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including approximately 30 other investor-owned, municipal and other utilities, as well as co-generators and other unregulated power generators with uncontracted excess capacity. Entities compete to provide energy on a short-term basis (i.e., hourly or daily) and on a long-term basis. Competition in these markets is primarily based on having available energy to sell to the wholesale market and the price. In Florida, available energy for the wholesale markets is affected by the state's PPSA, which sets the state's electric energy and environmental policy, and governs the building of new generation involving steam capacity of 75 MW or more. The PPSA requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. The effect of the PPSA has been to limit the number of unregulated generating units with excess capacity for sale in the wholesale power markets in Florida.

Tampa Electric is not a major participant in the wholesale market because it uses its lower-cost generation to serve its retail customers rather than the wholesale market.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring IOUs, such as Tampa Electric, to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 MW. These rules, which allow independent power producers and others to bid to supply the new generating capacity, provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids and provide more stringent standards for the IOUs to recover cost overruns in the event that the self-build option is deemed the most cost-effective.

Fuel

Approximately 62% of Tampa Electric's generation of electricity for 2014 was coal-fired, with natural gas representing approximately 38%. Tampa Electric used its generating units to meet approximately 95% of the total system load requirements, with the remaining 5% coming from purchased power. Tampa Electric's average delivered fuel cost per MMBTU and average delivered cost per ton of coal burned have been as follows:

Average cost per MMBTU	2014	2013	2012	2011	2010
Coal	$3.48	$3.36	$3.57	$3.46	$3.08
Oil	0.0	30.01	25.88	21.21	16.43
Gas (Natural)	5.68	5.23	5.34	6.20	6.74
Composite	4.16	4.00	4.19	4.38	4.46
Average cost per ton of coal burned	$83.70	$77.79	$84.59	$83.17	$74.80

Tampa Electric's generating stations burn fuels as follows: Bayside Station burns natural gas; Big Bend Station, which has SO_2 scrubber capabilities and NO_x reduction systems, burns a combination of high-sulfur coal and petroleum coke, No. 2 fuel oil and natural gas at CT4; Polk Power Station burns a blend of low-sulfur coal and petroleum coke (which is gasified and subject to sulfur and particulate matter removal prior to combustion), natural gas and oil; and Phillips Station, which burned residual fuel oil, was placed on long-term standby in September 2009.

Coal. Tampa Electric burned approximately 5.0 million tons of coal and petroleum coke during 2014 and estimates that its combined coal and petroleum coke consumption will be about 5.2 million tons in 2015. During 2014, Tampa Electric purchased approximately 76% of its coal under long-term contracts with five suppliers, and approximately 24% of its coal and petroleum coke in the spot market. Tampa Electric expects to obtain approximately 73% of its coal and petroleum coke requirements in 2015 under long-term contracts with five suppliers and the remaining 27% in the spot market.

Tampa Electric's long-term contracts provide for revisions in the base price to reflect changes in several important cost factors and for suspension or reduction of deliveries if environmental regulations should prevent Tampa Electric from burning the coal supplied, provided that a good faith effort has been made to continue burning such coal.

In 2014, approximately 84% of Tampa Electric's coal supply was deep-mined, approximately 7% was surface-mined and the remaining was petroleum coke. Federal surface-mining laws and regulations have not had any material adverse impact on Tampa Electric's coal supply or results of its operations. Tampa Electric cannot predict, however, the effect of any future mining laws and regulations.

Natural Gas. As of Dec. 31, 2014, approximately 90% of Tampa Electric's 1,500,000 MMBTU gas storage capacity was full. Tampa Electric has contracted for 80% of its expected gas needs for the April 2015 through October 2015 period. In early March 2015, to meet its generation requirements, Tampa Electric expects to issue RFPs to meet its remaining 2015 gas needs and begin contracting for its 2016 gas needs. Additional volume requirements in excess of projected gas needs are purchased on the short-term spot market.

Oil. Tampa Electric has agreements in place to purchase low sulfur No. 2 fuel oil for its Big Bend and Polk Power stations. All of these agreements have prices that are based on spot indices.

Franchises and Other Rights

Tampa Electric holds franchises and other rights that, together with its charter powers, govern the placement of Tampa Electric's facilities on the public rights-of-way as it carries for its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing Tampa Electric's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and not subject to amendment without the consent of Tampa Electric (except to the extent certain city ordinances relating to permitting and like matters are modified from time to time), although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. The City of Temple Terrace reserved the right to purchase Tampa Electric's property used in the exercise of its franchise if the franchise is not renewed. In the absence of such right to purchase caused by non-renewal, Tampa Electric would be able to continue to use public rights-of-way within the municipality based on judicial precedent, subject to reasonable rules and regulations imposed by the municipalities.

Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates through August 2043.

Franchise fees payable by Tampa Electric, which totaled $44.9 million at Dec. 31, 2014, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the County Commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County, Pinellas County and Polk County agreements. The agreement covering electric operations in Pasco County expires in 2023.

Environmental Matters

Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act, and material Clean Water Act implications and impacts by federal and state legislative initiatives. TEC, through its Tampa Electric and PGS divisions, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. See Environmental Compliance section of the MD&A for additional information.

Capital Expenditures

Tampa Electric's 2014 capital expenditures included approximately $66 million related to environmental compliance and improvement programs, primarily for upgrades to scrubbers and modifications to coal combustion by-product storage areas at the Big Bend Power Station. See the Liquidity, Capital Expenditures section of MD&A for information on estimated future capital expenditures related to environmental compliance.

PEOPLES GAS SYSTEM – Gas Operations

PGS operates as the gas division of TEC. PGS is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in the state of Florida.

Gas is delivered to the PGS system through three interstate pipelines. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that serves almost 354,000 customers. The system includes approximately 11,740 miles of mains and 6,800 miles of service lines (see PGS's Franchises and Other Rights section below).

PGS had 542 employees as of Dec. 31, 2014. A total of 141 employees in five of PGS's 14 operating divisions and call center are represented by various union organizations. In January 2015, 14 PGS employees were transferred to TECO Services, Inc.

In 2014, the total throughput for PGS was approximately 1.5 billion therms. Of this total throughput, 7% was gas purchased and resold to retail customers by PGS, 87% was third-party supplied gas that was delivered for retail transportation-only customers and 6% was gas sold off-system. Industrial and power generation customers consumed approximately 60% of PGS's annual therm volume, commercial customers consumed approximately 30%, off-system sales customers consumed 5% and the remaining balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations comprised about 37% of total revenues. Approximately 5% of revenues are attributed to governmental municipalities.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam. PGS has also seen increased interest and development in natural gas vehicles. There are 31 compressed natural gas filling stations connected to the PGS distribution system.

Revenues and therms for PGS for the years ended Dec. 31 were as follows:

	Revenues			Therms		
(millions)	2014	2013	2012	2014	2013	2012
Residential	$144.1	$128.1	$125.4	80.8	74.4	70.8
Commercial	139.1	133.4	134.1	460.5	438.1	421.4
Industrial	13.1	13.4	10.3	274.3	272.0	237.3
Off-system sales	39.4	56.7	73.7	84.0	143.1	224.0
Power generation	6.8	9.9	12.4	643.5	744.4	913.5
Other revenues	48.5	42.2	34.9			
Total	$391.0	$383.7	$390.8	1,543.1	1,672.0	1,867.0

No significant part of PGS’s business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on PGS. PGS’s business is not highly seasonal, but winter peak throughputs are experienced due to colder temperatures.

Regulation

The operations of PGS are regulated by the FPSC separately from the regulation of Tampa Electric. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC seeks to set rates at a level that provides an opportunity for a utility such as PGS to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The basic costs of providing natural gas service, other than the costs of purchased gas and interstate pipeline capacity, are recovered through base rates. Base rates are designed to recover the costs of owning, operating and maintaining the utility system. The rate of return on rate base, which is intended to approximate PGS’s weighted cost of capital, primarily includes its cost for debt, deferred income taxes at a zero cost rate, and an allowed ROE. Base rates are determined in FPSC revenue requirements proceedings which occur at irregular intervals at the initiative of PGS, the FPSC or other parties. For a description of recent proceeding activity, see the Regulation-PGS Rates section of MD&A.

PGS’s results reflect base rates established in May 2009, when the FPSC approved a base rate increase of $19.2 million which became effective on June 18, 2009 and reflects an ROE of 10.75%, which is the middle of a range between 9.75% and 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital, on an allowed rate base of $560.8 million.

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the PGA clause. This charge is designed to recover the costs incurred by PGS for purchased gas, and for holding and using interstate pipeline capacity for the transportation of gas it delivers to its customers. These charges may be adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a calendar year recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods. In November 2014, the FPSC approved PGS’s 2015 PGA cap factor for the period January 2015 through December 2015.

In addition to its base rates and PGA clause charges, PGS customers (except interruptible customers) also pay a per-therm charge for energy conservation and pipeline replacement programs. The conservation charge is intended to permit PGS to recover, on a dollar-for-dollar basis, prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are mandated by Florida law and approved and monitored by the FPSC. PGS is also permitted to earn a return, depreciation expenses and applicable taxes associated with the replacement of cast iron/bare steel infrastructure. PGS projects to have all cast iron and bare steel removed from its system within 8 years. Lastly, the FPSC requires natural gas utilities to offer transportation-only service to all non-residential customers.

In addition to economic regulation, PGS is subject to the FPSC’s safety jurisdiction, pursuant to which the FPSC regulates the construction, operation and maintenance of PGS’s distribution system. In general, the FPSC has implemented this by adopting the Minimum Federal Safety Standards and reporting requirements for pipeline facilities and transportation of gas prescribed by the U.S. Department of Transportation in Parts 191, 192 and 199, Title 49, of the Code of Federal Regulations.

PGS is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters (see the Environmental Compliance section of the MD&A).

Competition

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity, propane and fuel oil. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. PGS has a “NaturalChoice” program, offering unbundled transportation service to all non-residential customers, as well as residential customers consuming in excess of 1,999 therms annually, allowing these customers to purchase commodity gas from a third party but continue to pay PGS for the transportation. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 21,900 transportation-only customers as of Dec. 31, 2014 out of approximately 36,000 eligible customers.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly by transporting gas through other facilities and thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation-only services at discounted rates.

Gas Supplies

PGS purchases gas from various suppliers depending on the needs of its customers. The gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers.

Gas is delivered by FGT through 69 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's Jacksonville division receives gas delivered by a pipeline company through two gate stations located northwest of Jacksonville. Another pipeline company provides delivery through six gate stations. PGS also has one interconnection with its affiliate pipeline company in Clay County, Florida.

Companies with firm pipeline capacity receive priority in scheduling deliveries during times when the pipeline is operating at its maximum capacity. PGS presently holds sufficient firm capacity to permit it to meet the gas requirements of its system commodity customers, except during localized emergencies affecting the PGS distribution system and on abnormally cold days.

Firm transportation rights on an interstate pipeline represent a right to use the amount of the capacity reserved for transportation of gas on any given day. PGS pays reservation charges on the full amount of the reserved capacity whether or not it actually uses such capacity on any given day. When the capacity is actually used, PGS pays a volumetrically-based usage charge for the amount of the capacity actually used. The levels of the reservation and usage charges are regulated by the FERC. PGS actively markets any excess capacity available on a day-to-day basis to partially offset costs recovered through the PGA clause.

PGS procures natural gas supplies using base-load and swing-supply contracts with various suppliers along with spot market purchases. Pricing generally takes the form of either a variable price based on published indices or a fixed price for the contract term.

Neither PGS nor any of the interconnected interstate pipelines have storage facilities in Florida. PGS occasionally faces situations when the demands of all of its customers for the delivery of gas cannot be met. In these instances, it is necessary that PGS interrupt or curtail deliveries to its interruptible customers. In general, the largest of PGS's industrial customers are in the categories that are first curtailed in such situations. PGS's tariff and transportation agreements with these customers give PGS the right to divert these customers' gas to other higher priority users during the period of curtailment or interruption. PGS pays these customers for such gas at the price they paid their suppliers or at a published index price, and in either case pays the customer for charges incurred for interstate pipeline transportation to the PGS system.

Franchises and Other Rights

PGS holds franchise and other rights with 113 municipalities throughout Florida. These franchises govern the placement of PGS's facilities on the public rights-of-way as it carries on its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing PGS's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and are not subject to amendment without the consent of PGS, although in certain events they are subject to forfeiture.

Municipalities are prohibited from granting any franchise for a term exceeding 30 years. Several franchises contain purchase options with respect to the purchase of PGS's property located in the franchise area, if the franchise is not renewed; otherwise, based on judicial precedent, PGS is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

PGS's franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from the present through 2044. PGS expects to negotiate sixteen franchises in 2015. Franchise fees payable by PGS, which totaled $8.7 million at Dec. 31, 2014, are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are collected from only those customers within each franchise area.

Utility operations in areas outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commission of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates, and these rights are, therefore, considered perpetual.

Environmental Matters

PGS's operations are subject to federal, state and local statutes, rules and regulations relating to the discharge of materials into the environment and the protection of the environment that generally require monitoring, permitting and ongoing expenditures. TEC is one of several PRPs for certain superfund sites and, through PGS, for former manufactured gas plant sites. See Note 12 to the TECO Energy Consolidated Financial Statements and the Environmental Compliance section of the MD&A for additional information.

Capital Expenditures

During the year ended Dec. 31, 2014, PGS did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2015 through 2019 period.

NEW MEXICO GAS COMPANY

NMGC is engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in the state of New Mexico. NMGC had approximately 700 employees as of Dec. 31, 2014.

NMGC operates a natural gas distribution system that serves approximately 513,000 customers. The system includes approximately 1,600 miles of transmission pipeline, 10,200 miles of mains and 521,400 service lines (see NMGC's Franchises and Other Rights section below). NMGC's system interconnects with five interstate pipelines.

For the last four months of 2014 (since the acquisition by TECO Energy), the total throughput for NMGC was over 275 million therms. Of this total throughput, 53% was gas purchased and resold to retail customers by NMGC, 41% was third-party supplied gas that was delivered for retail transportation-only customers and 6% was gas sold or transported off system. Industrial and power generation customers consumed approximately 27% of NMGC's 2014 annual therm volume, commercial customers consumed approximately 31%, off-system transportation customers consumed 6% and the remaining balance was consumed by residential customers.

Natural gas has historically been used primarily for residential heating purposes in New Mexico. The residential market represents approximately 37% of total annual therm volume and 72% of NMGC's total annual revenues. Approximately 4% of annual revenues are attributed to facilities of governmental entities, including the federal government, the State of New Mexico, school districts and municipalities.

Revenues and therms for NMGC for the four months ended Dec. 31, 2014 were as follows:

(millions)	Revenues 2014	Therms 2014
Residential	$ 99.9	108.2
Commercial	27.1	37.4
Industrial	0.9	1.6
On system transportation	7.1	111.6
Off system transportation	0.3	16.5
Other revenues	2.2	
Total	$ 137.5	275.3

No significant part of NMGC's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on NMGC. NMGC's business is seasonal with much higher volumes and revenues experienced during colder winter months.

Regulation

The operations of NMGC are regulated by the NMPRC. The NMPRC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the NMPRC seeks to set rates at a level that provides an opportunity for a utility such as NMGC to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The basic costs of providing natural gas service, other than the costs of purchased gas, gas storage services and interstate pipeline capacity, are recovered through base rates. Base rates are designed to recover the costs of owning, operating and maintaining the utility system. The rate of return on rate base, which is intended to approximate NMGC's weighted cost of capital, primarily includes its cost for long-term debt and an allowed ROE. Base rates are determined in NMPRC revenue requirements proceedings which occur at irregular intervals at the initiative of NMGC, the NMPRC or other parties. For a description of recent proceeding activity, see the Regulation-NMGC Rates section of MD&A.

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC’s base rates by approximately $34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on Jan. 31, 2012, revising, among other things, base rates for all service provided on or after Feb. 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC’s base rate revenue by approximately $21.5 million on a normalized annual basis. The monthly residential customer access fee increased from $9.59 to $11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017 and customers will receive a $2 to $4 million credit per year until the next rate case as reported in Note 21 to the TECO Energy, Inc. Consolidated Financial Statements.

NMGC recovers the costs it pays for gas supply and interstate transportation for system supply through the PGAC. This charge is designed to recover the costs incurred by NMGC for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. On a monthly basis, NMGC estimates its cost of gas for the next month (taking into consideration the expected cost of gas to be purchased for the next month, expected demand and any prior month under-recovery or over-recovery of NMGC’s cost of gas) and sets the GCBF rate to be used in the next month to recover those estimated costs. For any increase or decrease in cost of gas sold, there is a corresponding increase or decrease in revenue collected through the PGAC. NMGC also has regulatory authority to include a simple interest charge or credit based upon the month-end balance of the PGAC under-recovery or over-recovery of NMGC’s cost of gas. NMGC’s annual PGAC period runs from Sept. 1 to Aug. 31. The NMPRC requires that NMGC file a reconciliation of the PGAC period costs and recoveries, annually in December. Additionally, NMGC must file a PGAC Continuation Filing with the NMPRC every four years. The purpose of the PGAC Continuation Filing is to establish that the continued use of the PGAC is reasonable and necessary. In January 2013, the NMPRC approved the PGAC Continuation Filing allowing for continued use of the PGAC for another four years.

In addition to its base rates and PGAC, NMGC’s residential customers and customers utilizing NMGC’s small and medium volume general services also pay a per-therm charge for energy conservation. The conservation charge is intended to permit NMGC to recover, on a dollar-for-dollar basis, prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are approved and monitored by the NMPRC. The NMPRC requires natural gas utilities to offer transportation-only service to all customer classes.

In addition to economic regulation, NMGC is subject to the NMPRC's safety jurisdiction, pursuant to which the NMPRC regulates the construction, operation and maintenance of NMGC's distribution system. In general, the NMPRC has implemented this by adopting the Minimum Federal Safety Standards and reporting requirements for pipeline facilities and transportation of gas prescribed by the U.S. Department of Transportation in Parts 191, 192 and 199, Title 49, Code of Federal Regulations.

NMGC is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters (see the Environmental Matters section).

Competition

Although NMGC is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity, propane and fuel oil. NMGC has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

Pursuant to New Mexico statutes and NMPRC rules and regulations, NMGC is required to provide transportation-only services for all customer classes. NMGC receives its base rates for distribution gas delivery services regardless of whether a customer decides to opt for transportation-only service or continue on NMGC's gas commodity sales service. During the four months ended Dec. 31, 2014, NMGC had approximately 4,000 transportation-only end-use customers and approximately 509,000 gas commodity sales service customers. Transportation-only throughput represented 46.5% of total system throughput and 5.4% of total revenue for the four months ended Dec. 31, 2014.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly by transporting gas through other transmission and distribution providers and thereby bypassing NMGC transmission and distribution facilities. In response to this competition, NMGC has developed various programs, including the provision of transportation-only services at discounted rates.

Gas Supplies

NMGC’s service territory is situated between two large natural gas production basins (the San Juan Basin to the northwest of the Company’s service territory and the Permian Basin to the southeast of NMGC’s service territory). Natural gas is transported from these production basins on major interstate pipelines to NMGC’s intrastate transmission system and then to customers using its distribution system. The San Juan Basin typically supplies 85% of NMGC’s gas supply, with the Permian Basin supplying the remaining balance.

NMGC’s transmission and distribution system interconnects with five interstate pipelines owned by various pipeline companies. NMGC has firm pipeline capacity contracts with these pipeline companies. To enhance gas supply and transportation availability, NMGC has an ownership interest in the Blanco Hub, one of the central supply and marketing points in the San Juan Basin. The Blanco Hub interconnects with NMGC's transmission system as well as major nearby gathering systems and interstate pipelines. To provide for system balancing and peak day supply requirements, NMGC contracts for 3.2 billion cubic feet (Bcf) of underground gas storage capacity and gas storage services in an underground facility in west Texas. This storage facility is connected to two major interstate pipelines that, in turn, connect to NMGC’s transmission and distribution system.

Gas is purchased from various suppliers at market pools and processing plant tailgates from marketers and producers. NMGC has negotiated standard terms and conditions for the purchase of natural gas under the NAESB and the Gas Industry Standards Board forms of agreement. NMGC purchases gas for resale to its jurisdictional gas sales customers in accordance with an annual gas supply plan filed with the NMPRC.

Gas price spikes, which can occur in high demand winter months, have the potential to significantly increase customer bills. To provide a degree of price protection, NMGC utilizes a hedging plan for a portion of the winter gas supply. The gas hedging activity is discussed in more detail in Note 16 of the TECO Energy, Inc. Consolidated Financial Statements.

Franchises and Other Rights

Many of NMGC’s transmission and distribution facilities are located on lands that require the grant of rights-of-way or franchises (collectively, ROW) from non-tribal governmental entities, Native American tribes and pueblos, or private landowners. In some cases, renewed ROWs must be submitted to the Federal Bureau of Indian Affairs (BIA) for approval. For the four months ended Dec. 31, 2014, NMGC incurred expenditures for ROW renewals on Native American tribal and pueblo lands that amounted to $7.9 million.

In 2011, the New Mexico legislature passed legislation confirming the validity and enforceability of agreements with public utilities that provide access to public rights of way, including expired agreements that have continued to be honored by both the public utility and the local government according to their terms, regardless of the expiration date of the agreements. Accordingly, some of NMGC’s expired ROWs remain in effect by acquiescence, though NMGC expects to enter into negotiations over those expired ROWs and renew them. Based on current renewal experience with ROWs on Native American tribal and pueblo lands, NMGC believes that it is likely those ROWs will be renewed at prices that are significantly higher than historical levels. NMGC does not have condemnation rights on Native American tribal and pueblo lands, and, if it is unsuccessful in renewing some or all of these expiring or expired ROWs, it could be obligated to remove its facilities from, or abandon its facilities on, the property covered by the ROWs and seek alternative locations for its transmission or distribution facilities. With respect to land held by non-tribal governmental entities and privately-held land, however, NMGC may have condemnation rights and, thus, in the case where ROWs cannot be renewed by negotiation, NMGC would likely exercise such rights rather than remove or abandon facilities and find alternative locations for such facilities. Historically, ROW costs have been recovered in rates charged to customers, and NMGC will continue to seek to recover ROW costs in future rates charged to customers.

Environmental Matters

NMGC's operations are subject to federal, state and local statutes, rules and regulations relating to the discharge of materials into the environment and the protection of the environment that generally require monitoring, permitting and ongoing expenditures.

NMGC has no former MGP sites or material environmental liabilities. NMGC does not own any facilities or sites where investigation, remediation, or monitoring of environmental conditions is ongoing or anticipated to be required. NMGC is unaware of any soil or groundwater contamination for which it might be responsible under federal, state, or local laws or regulations. NMGC is a conditionally exempt small quantity generator with less than 100 kilograms of hazardous waste per month. Wastes are routinely characterized to determine whether or not they are subject to applicable hazardous waste regulations.

NMGC currently maintains two Title V (major source) air permits, for the Star Lake and Espejo Compressor Stations, as the federal EPA Region 6 currently does not issue minor source permits for Title V purposes to facilities on Native American or Pueblo lands. The remainder of its compressor stations are classified as minor sources. A minor source is one which has potential uncontrolled emissions less than 100 tons per year per regulated pollutant.

See Environmental Compliance section of the MD&A for additional information.

Capital Expenditures

During the four months ended Dec. 31, 2014, NMGC did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2015 through 2019 period.

TECO COAL

TECO Coal, a wholly owned subsidiary of TECO Energy, Inc., has subsidiaries operating surface and underground mines as well as coal processing facilities in eastern Kentucky, Tennessee and southwestern Virginia.

TECO Coal owns no operating assets but holds all of the common stock of Gatliff Coal Company, Rich Mountain Coal Company, Clintwood Elkhorn Mining Company, Pike-Letcher Land Company, Premier Elkhorn Coal Company, Perry County Coal Corporation and Bear Branch Coal Company. TECO Coal owns, controls and operates, by lease or mineral rights, surface and underground mines and coal processing and loading facilities. TECO Coal produces, processes and sells bituminous, predominately low sulfur coal of metallurgical, PCI, steam and industrial grades.

TECO Coal is a supplier of metallurgical and PCI coal for use in the steel-making process and a supplier of thermal coal to electric utilities and manufacturing industries. TECO Coal also exports metallurgical and PCI coals internationally, primarily to European markets.

Metallurgical, PCI and industrial stoker coals accounted for approximately 60% of TECO Coal’s 2014 coal sales volume. Thermal coal accounted for approximately 40% of 2014 coal sales volume.

On Oct. 17, 2014, TECO Diversified entered into an agreement to sell all of its ownership interest in TECO Coal. On Feb. 5, 2015, the agreement was amended to extend the closing date to Mar. 13, 2015 and to establish a purchase price of $80 million plus any cash on hand as of the closing, subject to customary post-closing adjustments, plus contingent payments of up to $60 million that may be paid between 2015 and 2019 depending on specified coal benchmark prices. As a result, TECO Coal is accounted for as an asset held for sale and discontinued operation.

In 2014, discontinued operations resulted in a loss of $82.0 million comprised of the full-year operating results discussed below and $76.4 million of after-tax impairment charges and tax valuation allowances. TECO Coal’s 2014 loss from operations was $5.6 million on sales of 5.5 million tons, compared with net income of $9.0 million on 5.8 million tons sold in 2013. The 2014 results reflect selling prices and costs associated with reductions in personnel and steps taken in advance of closing the sale of the company.

See Notes 14, 19, 20 and 23 to the TECO Energy, Inc. Consolidated Financial Statements for more information.

TECO GUATEMALA

TECO Guatemala, a wholly owned subsidiary of TECO Energy, had subsidiaries with interests in independent power projects in Guatemala. On Sept. 27, 2012, TECO Guatemala entered into an agreement to sell all of the equity interests in the Alborada and San José power stations, related facilities and operations in Guatemala for a total purchase price of $227.5 million in cash. The sale of the Alborada Power Station closed on the same date for a selling price of $12.5 million. On Dec. 19, 2012, the closing occurred on the (i) San José power station and related facilities in Guatemala for a purchase price of $213.5 million and (ii) the remaining TECO Guatemala operations company for a purchase price of $1.5 million.

See Notes 19 and 20 to the TECO Energy, Inc. Consolidated Financial Statements for more information regarding these discontinued operations and asset dispositions.

While TECO Energy and its subsidiaries no longer have assets or operations in Guatemala, TECO Guatemala Holdings, a wholly owned subsidiary of TECO Energy, has retained its rights under an arbitration claim against the Republic of Guatemala under the DR-CAFTA. See Note 12 to the TECO Energy, Inc. Consolidated Financial Statements for more information.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages, current positions and principal occupations during the last five years of the current executive officers of TECO Energy are described below.

Name	Age	Current Positions and Principal Occupations During The Last Five Years
John B. Ramil	59	President and Chief Executive Officer, TECO Energy, Inc., and Chief Executive Officer, Tampa Electric Company, August 2010 to date; President and Chief Operating Officer, TECO Energy, Inc., July 2004 to August 2010.
Charles A. Attal, III	55	Senior Vice President-General Counsel, Chief Legal Officer and Chief Ethics and Compliance Officer, TECO Energy, Inc. and General Counsel and Chief Ethics and Compliance Officer, Tampa Electric Company, June 2014 to date; and Senior Vice President-General Counsel and Chief Legal Officer, TECO Energy, Inc. and General Counsel of Tampa Electric Company, February 2009 to June 2014.
Phil L. Barringer	61	Senior Vice President of Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., Jan. 30, 2013 to date; Vice President of Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., Jan. 1, 2013 to Jan. 30, 2013; Chief Human Resources Officer and Procurement Officer, Tampa Electric Company, January 2013 to date; Vice President-Human Resources of TECO Energy, Inc. and Tampa Electric Company, July 2009 to December 2012; and President, TECO Guatemala, July 2009 to date (operating companies sold December 2012).
Sandra W. Callahan	62	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TECO Energy, Inc., February 2011 to date, and Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), Tampa Electric Company, October 2009 to date; and Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TECO Energy, Inc., October 2009 to February 2011.
Gordon L. Gillette	55	President, Tampa Electric Company, July 2009 to date.
Ryan A. Shell	49	President, New Mexico Gas Company, Inc., Dec. 31, 2014 to date; Vice President of Finance and Shared Services, New Mexico Gas Company, Inc., September 2014 to Dec. 31, 2014; Vice President of Finance and Treasurer, New Mexico Gas Company, Inc., February 2013 to September 2014; and Vice President, Controller and Treasurer, New Mexico Gas Company, Inc., January 2009 to February 2013.
Clark Taylor	65	President, TECO Coal Corporation, April 2011 to date; and prior thereto, Vice President-Controller, TECO Coal Corporation.

There is no family relationship between any of the persons named above or between executive officers and any director of the company. The term of office of each officer extends to the meeting of the Board of Directors following the next annual meeting of shareholders, scheduled to be held on Apr. 29, 2015, and until such officer’s successor is elected and qualified.

Item 1A. RISK FACTORS.

General Business and Operational Risks

General economic conditions may adversely affect our businesses.

Our businesses are affected by general economic conditions. In particular, growth in the regulated utilities' service areas in Florida and New Mexico is important to the realization of annual energy sales growth for Tampa Electric, PGS and NMGC. Any weakening of economic conditions could adversely affect our utilities' expected performance and their ability to collect payments from customers.

Our electric and gas utilities are highly regulated; changes in regulation or the regulatory environment could reduce revenues or increase costs or competition.

Our electric and gas utilities operate in highly regulated industries. Their retail operations, including the prices charged, are regulated by the FPSC in Florida and the NMPRC in New Mexico, and Tampa Electric's wholesale power sales and transmission services are subject to regulation by the FERC. Changes in regulatory requirements or adverse regulatory actions could have an adverse effect on our utilities' financial performance by, for example, reducing revenues, increasing competition or costs, threatening investment recovery or impacting rate structure.

If Tampa Electric or PGS earn returns on equity above their respective allowed ranges, the earnings could be subject to review by the FPSC which could result in refunds to customers, which could reduce earnings and cash flow.

Various factors relating to the integration of NMGC could adversely affect our business and operations.

Based on the completion of the permanent financing for the NMGC acquisition, we currently expect NMGC to be accretive to earnings for the full-year 2015 period. However, the anticipated accretion to earnings from NMGC during this integration period is based on estimates of synergies from the transaction and growth in the New Mexico economy, which are dependent on local and global economic conditions and other factors, which may materially change, including:

- our estimate of NMGC's expected operating performance after the completion of the transaction may vary significantly from actual results;
- Over time, we will be making significant capital investments to convert several NMGC computer systems to the systems that we use in Florida. These conversions may not be accomplished on time or on budget, which would increase costs for NMGC. In addition, the time required to convert these systems will cause NMGC to operate the existing systems past the end of their normal lives, which could reduce reliability.
- the potential loss of key employees of TECO Energy or NMGC who may be uncertain about their future roles in the TECO Energy / NMGC organization.

Negative impacts from these factors could have an adverse effect on the anticipated benefits of the transaction or our business, financial condition, results of operations or stock price.

We have incurred and will continue to incur significant integration costs in connection with the NMGC acquisition.

We incurred significant transaction costs in connection with the execution and consummation of the NMGC acquisition as well as the related financing transactions. In addition, we are in the process of integrating NMGC into TECO Energy following the closing of the NMGC acquisition on Sept. 2, 2014. Although we anticipate achieving synergies in connection with the NMGC acquisition, we also expect to incur costs to achieve these synergies. In 2014, we incurred transaction and integration costs in connection with the NMGC acquisition of $16.6 million. We anticipate that we will incur additional non-recurring charges in connection with this integration, including charges associated with integrating processes and systems. At this time, we cannot identify the timing, nature and amount of all such additional charges. We have identified some, but not all, of the actions necessary to achieve our anticipated synergies. Accordingly, the synergies expected from the acquisition of NMGC may not be achievable in our anticipated amount or timeframe or at all.

Changes in the environmental laws and regulations affecting our businesses could increase our costs or curtail our activities.

Our businesses are subject to regulation by various governmental authorities dealing with air, water and other environmental matters. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on us or require us to curtail some of our businesses' activities.

Proposed regulations on the disposal and/or storage of CCRs could add to Tampa Electric's operating costs.

In response to a coal ash pond failure in December 2008 at another utility, the EPA proposed new regulations for the management and disposal of CCRs. A preliminary draft of the final rule was issued in December 2014, which designated CCRs as non-hazardous wastes. The designation of CCRs as non-hazardous waste in the preliminary draft of the final rule allows for the continued operation of ash impoundments on Tampa Electric's facilities; however, this designation may impose additional administrative and compliance requirements, which could increase costs.

It is expected that the rules, once made final, will be subjected to litigation, which could have a material impact on both the content and the timing of the implementation of the rules. Accordingly, the outcome of this rule-making process and its impact on our businesses cannot be determined at this time. While certain costs related to environmental compliance are currently recoverable from customers under Florida's ECRC, we cannot be assured that any increased costs associated with complying with those regulations will be eligible for such treatment.

Federal or state regulation of GHG emissions, depending on how they are enacted, could increase our costs or the rates charged to our customers, which could curtail sales.

Among our companies, Tampa Electric has the most significant number of stationary sources with air emissions. While GHG emission regulations have been proposed, both at the federal level and in various states, none has been passed at this time and, therefore, costs to reduce GHGs are unknown. Presently there is no viable technology to remove CO_2 post-combustion from

19

conventional coal-fired units such as Tampa Electric's Big Bend units. New rules requiring post-combustion CO_2 removal could require significant investment in what is essentially experimental technology, costly conversion to natural gas fuel, or a premature shut-down of the units, which would result in non-cash write-offs.

Current regulation in Florida allows utility companies to recover from customers prudently incurred costs for compliance with new state or federal environmental regulations. Tampa Electric would expect to recover from customers the costs of power plant modifications or other costs required to comply with new GHG emission regulation. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but we cannot be assured that the FPSC would grant such recovery.

In a June 25, 2013, memorandum, President Obama directed the EPA to issue new emissions standards for future power plants as well as modified, reconstructed or existing power plants to reduce GHG emissions. The new standards, which were released in the fall of 2013, essentially mandate that no new coal fired power plants will be constructed in the U.S. On June 2, 2014, the EPA released a comprehensive proposed rule which it calls the "Clean Power Plan," aiming to cut GHG emissions from existing power plants by 30% from their 2005 levels by 2030, with an interim goal for the period from 2020 through 2029. Under the proposed rule, each state would have to reduce CO_2 emissions on a state-wide basis by an amount specified by the EPA. The EPA determined the target amount for each state based on its view of each state's options, including: making power plant efficiency upgrades; shifting from coal to natural gas generation; investing in zero- and low-emitting power sources, such as renewable and nuclear energy; and implementing customer energy efficiency programs. Because the 30% reduction target is an average across all states, some states have higher or lower target emission reduction goals under the proposed rule than the average. Based on current emissions, Florida has a reduction goal of 38%, which is higher than the national average. Under the proposed rules, states will have flexibility in designing programs to meet their emission reduction targets, including the four approaches noted above or any other measures they choose to adopt, for example, carbon tax and cap-and-trade. The EPA is scheduled to finalize the rule by June 1, 2015, and states will have until June 30, 2016, to submit plans to achieve their target emission reductions (subject to extension and EPA approval of the states' plans). It is unclear whether Florida's proposed implementation plan will take into consideration emission reductions achieved prior to 2005 or if that baseline year will be changed in the comment process. The 2005 baseline year does not take into consideration the significant reductions in greenhouse gas emissions we achieved prior to 2005 (a reduction of approximately five million tons since 1998). If the 2005 baseline year remains unchanged (which due to our previous reductions in greenhouse gas emissions was our lowest emitting year), it may be more difficult for us to achieve the proposed reductions than other utilities in a cost-effective manner, especially when compared to utilities in other states that have lower emission reduction targets under the proposed rules. It is expected that the rules will be subjected to litigation, which could have a material impact on both the content and the timing of the implementation of the rules. Accordingly, the outcome of this rule-making process and its impact on our businesses cannot be determined at this time; however, it could result in increased operating costs, or decreased operations at Tampa Electric's coal-fired plants. While certain costs related to environmental compliance are currently recoverable from customers under Florida's ECRC, we cannot be assured that any increased costs associated with complying with those regulations will be eligible for such treatment.

Among other rules, the EPA has proposed or finalized a number of new rules, including the CAIR/CSAPR and Hazardous Air Pollutants ("HAPS") Maximum Achievable Control Technology ("MACT") for emissions into the air, and a number of new rules focused on water use and discharges from power generation facilities.

These air focused rules impose stringent reductions in several pollutants from electric utility steam generators, primarily coal-fired, but including oil-fired as well. If the CSAPR rule is implemented as planned, the EPA has estimated that the implementation of CSAPR would require significant investment in pollution-control equipment for units not already equipped or could result in the retirement of primarily smaller, older coal-fired power stations that do not currently have state-of-the-art air pollution-control equipment already installed. The retirement of these units or switching to other fuels for compliance with this rule is likely to reduce overall demand for coal, which could reduce sales and financial results at TECO Coal.

The EPA's proposed water focused rules could limit the supply of water available to our power generating facilities, which would require us to invest significant capital in new equipment and would increase our operating costs.

A mandatory RPS could add to Tampa Electric's costs and adversely affect its operating results.

In past sessions of the Florida Legislature, an RPS was debated but ultimately not enacted; however, an RPS standard could be enacted in the future. In addition, there is the potential that legislation could be proposed in the U.S. Congress to introduce an RPS at the federal level. It remains unclear if or when action on such legislation would be completed. Tampa Electric could incur significant costs to comply with an RPS, and Tampa Electric's operating results could be adversely affected if Tampa Electric were not permitted to recover these costs from customers through the ECRC.

The nation is increasingly dependent on natural gas to generate electricity and as an alternative to higher cost petroleum fuels. There may not be adequate infrastructure to deliver adequate quantities of natural gas to meet the expected future demand, and the expected higher demand for natural gas may lead to increasing costs for the commodity.

In the United States, utilities are increasingly relying on natural gas for new electric generating plants in response to GHG emissions concerns and attractive natural gas prices. Industrial customers and vehicle fleets are converting to natural gas based on attractive economics and lower emissions. Currently, there is an adequate supply and infrastructure to meet demand for natural gas in Florida and nationally. However, if future supplies are inadequate or if significant new investment is required to install the pipelines necessary to transport the gas, the cost of natural gas could rise.

Currently, our electric and gas utilities are allowed to pass the cost for the commodity gas and transportation services to customers without profit. Changes in commodity gas cost recovery regulations could reduce earnings if they required Tampa Electric, PGS or NMGC to bear a portion of the increased cost. In addition, increased costs to customers could result in lower sales.

Our businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations.

All of our businesses are affected by variations in general weather conditions and unusually severe weather. Energy sales by our electric and gas utilities are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. If climate change or other factors cause significant variations from normal weather, this could have a material impact on energy sales.

PGS and NMGC, which typically have short but significant winter peak periods that are dependent on cold weather, are more weather-sensitive than Tampa Electric, which has both summer and winter peak periods. NMGC typically earns all of its net income in the first and fourth quarters, due to winter weather. Mild winter weather can negatively impact results at Tampa Electric, PGS and NMGC.

The state of Florida is exposed to extreme weather, including hurricanes, which can cause damage to our facilities and affect our ability to serve customers. There is the potential for gas customer service interruptions and system reliability problems during periods of extreme cold weather in New Mexico.

As a company with electric service and natural gas operations in peninsular Florida, we are exposed to extreme weather events, such as hurricanes. Extreme weather conditions can be destructive, causing outages and property damage that require the company to incur additional expenses. Extensive customer outages could reduce revenue collections. If warmer temperatures lead to changes in extreme weather events (increased frequency, duration and severity), these expenses could be greater.

While the company has storm preparation and recovery plans in place, and Tampa Electric and PGS have historically been granted regulatory approval to recover or defer the majority of significant storm costs incurred, extreme weather still poses risks to our operations and storm cost-recovery petitions may not always be granted or may not be granted in a timely manner. If costs associated with future severe weather events cannot be recovered in a timely manner, or in an amount sufficient to cover actual costs, our financial condition and operating results could be adversely affected.

In the past, in New Mexico supplies of natural gas from natural gas wells have been disrupted and interstate pipelines were unable to reliably deliver gas during periods of extreme cold weather, which caused retail customer service interruptions; and these types of disruptions could occur in the future. NMGC is evaluating significant capital investments to ensure reliable supplies of natural gas for its customers if such interruptions occur again. Future service interruptions could lead to customer lawsuits or cause NMGC to make additional capital investments, which could raise costs to customers.

NMGC operates high-pressure natural gas transmission pipelines, which involve risks that may result in accidents or otherwise affect our operations.

There are a variety of hazards and operating risks inherent in operating high-pressure natural gas transmission pipelines, such as leaks, explosions, mechanical problems, activities of third parties and damage to pipelines, facilities and equipment caused by floods, fires and other natural disasters that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, known as High Consequence Areas (HCAs) the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings, financial condition and cash flows.

NMGC's high-pressure transmission pipeline operations are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Our pipeline operations are subject to pipeline safety regulation administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the DOT. These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines. The regulations determine the pressures at which our pipelines can operate.

PHMSA is designing an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand pipeline integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. Pipeline failures or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have a material adverse effect on our operations, earnings, financial condition and cash flows.

Commodity price changes may affect the operating costs and competitive positions of our businesses.

All of our businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services.

In the case of Tampa Electric, fuel costs used for generation are affected primarily by the cost of coal and natural gas. Tampa Electric is able to recover prudently incurred costs of fuel through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

The ability to make sales and the margins earned on wholesale power sales are affected by the cost of fuel to Tampa Electric, particularly as it compares to the costs of other power producers.

In the case of PGS and NMGC, costs for purchased gas and pipeline capacity are recovered through retail customers' bills, but increases in gas costs affect total retail prices and, therefore, the competitive position of PGS and NMGC relative to electricity, other forms of energy and other gas suppliers.

Results at our companies may be affected by changes in customer energy-usage patterns.

For the past several years, at Tampa Electric, and electric utilities across the country, weather-normalized electricity consumption per residential customer declined due to the combined effects of voluntary conservation efforts, economic conditions, improvements in lighting and appliance efficiency, trends toward smaller single family houses and increased multi-family housing.

Forecasts by our companies are based on normal weather patterns and historical trends in customer energy-usage patterns. The ability of our utilities to increase energy sales and earnings could be negatively impacted if customers continue to use less energy in response to increased energy efficiency, economic conditions or other factors.

Our computer systems and the infrastructure of our utility companies may be subject to cyber (primarily electronic or internet-based) or physical attacks, which could disrupt operations, cause loss of important data or compromise customer, employee-related or other critical information or systems, or otherwise adversely affect our business and financial results and condition.

There have been an increasing number of cyber-attacks on companies around the world, which have caused operational failures or compromised sensitive corporate or customer data. These attacks have occurred over the Internet, through malware, viruses, attachments to e-mails, through persons inside of the organization or through persons with access to systems inside of the organization.

We have security systems and infrastructure in place that are designed to prevent such attacks, and these systems are subject to internal, external and regulatory audits to ensure adequacy. Despite these efforts, we cannot be assured that a cyber-attack will not cause electric or gas system operational problems, disruptions of service to customers, compromise important data or systems, or subject us to additional regulation, litigation or damage to our reputation.

There have also been physical attacks on critical infrastructure at other utilities. While the transmission and distribution system infrastructure of our utility companies are designed and operated in such a manner to mitigate the impact of this type of attack, in the event of a physical attack that disrupts service to customers, revenues would be reduced and costs would be incurred to repair any damage. These types of events, either impacting our facilities or the industry in general, could also cause us to incur additional security- and insurance-related costs, and could have adverse effects on our business and financial results and condition.

We rely on some natural gas transmission assets that we do not own or control to deliver natural gas. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver natural gas and supply natural gas to our electric generating stations may be hindered.

We depend on transmission facilities owned and operated by other utilities and energy companies to deliver the natural gas we sell to the wholesale and retail markets, as well as the natural gas we purchase for use in our electric generation facilities. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual and service obligations may be hindered.

Potential competitive changes may adversely affect our regulated electric and gas businesses.

There is competition in wholesale power sales across the country. Some states have mandated or encouraged competition at the retail level and, in some situations, required divestiture of generating assets. While there is active wholesale competition in Florida, the retail electric business has remained substantially free from direct competition. Although not expected in the foreseeable future, changes in the competitive environment occasioned by legislation, regulation, market conditions or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect Tampa Electric’s business and its expected performance.

The gas distribution industry has been subject to competitive forces for several years. Gas services provided by our gas utilities are unbundled for all non-residential customers. Because our gas utilities earn margins on distribution of gas but not on the commodity itself, unbundling has not negatively impacted their results. However, future structural changes that we cannot predict could adversely affect PGS and NMGC.

Increased customer use of distributed generation could adversely affect our regulated electric utility business.

In many areas of the country there is growing use of rooftop solar panels, small wind turbines and other small-scale methods of power generation, called distributed generation, by individual residential, commercial and industrial customers. Distributed generation is encouraged and supported by various special interest groups, tax incentives, renewable portfolio standards and special rates designed to support such generation. Additionally, the EPA’s proposed “Clean Power Plan” rule, if enacted as proposed, could have the effect of providing greater incentives for distributed generation in order to meet state-based emission reduction targets under the proposed rule. See “Federal or state regulation of GHG emissions depending on how they are enacted, could increase our costs or the rates charged to our customers, which could curtail sales.”

Increased usage of distributed generation, particularly in those states where solar or wind resources are the most abundant, is reducing utility electricity sales but not reducing the need for ongoing investment in infrastructure to maintain or expand the transmission and distribution grid to reliably serve customers. Continued utility investment not supported by increased energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

There is proposed legislation to potentially be debated in the 2015 Florida legislative session, and there is a potential for an amendment to the Florida constitution to be on the ballot in 2016 that would promote increased use of solar energy to generate electricity.

Proposed action by the Florida legislature in 2015 and a potential amendment to the Florida constitution in 2016 would encourage the installation of solar arrays to generate electricity by retail customers and third parties, and to allow sales of electricity by non-utility generators. Increased use of solar generation and sales by third parties would reduce energy sales and revenues at Tampa Electric. In addition, Tampa Electric could make investments in facilities to serve customers during periods that solar energy is not available that would not be profitable.

The value of our existing deferred tax benefits are determined by existing tax laws, and could be negatively impacted by changes in these laws.

"Comprehensive tax reform" remains a topic of discussion in the U.S. Congress. Such legislation could significantly alter the existing tax code, including a reduction in corporate income tax rates. Although a reduction in the corporate income tax rate could result in lower future tax expense and tax payments, it would reduce the value of our existing deferred tax asset and could result in a charge to earnings from the write-down of that asset, and would reduce future cash flow at the parent company.

Impairment testing of certain long-lived assets could result in impairment charges.

We assess long-lived assets and goodwill for impairment annually or more frequently if events or circumstances occur that would more likely than not reduce the fair value of those assets below their carrying values. To the extent the value of goodwill or a long-lived asset becomes impaired, we may be required to record non-cash impairment charges that could have a material adverse impact on our financial condition and results from operations. In connection with the NMGC acquisition, we recorded additional goodwill and long-lived assets that could become impaired.

Financing Risks

We have substantial indebtedness, which could adversely affect our financial condition and financial flexibility.

We have substantial indebtedness, which has resulted in fixed charges we are obligated to pay. The level of our indebtedness and restrictive covenants contained in our debt obligations could limit our ability to obtain additional financing.

TECO Energy, TECO Finance, TEC, NMGC and NMGI must meet certain financial covenants as defined in the applicable agreements to borrow under their respective credit facilities. Also, TECO Energy and its subsidiaries have certain restrictive covenants in specific agreements and debt instruments. See the Credit Facilities section and Significant Financial Covenants table in the Liquidity, Capital Resources sections of the Management’s Discussion & Analysis for descriptions of these covenants.

Although we were in compliance with all required financial covenants as of Dec. 31, 2014, we cannot assure compliance with these financial covenants in the future. Our failure to comply with any of these covenants or to meet our payment obligations could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. We may not have sufficient working capital or liquidity to satisfy our debt obligations in the event of an acceleration of all or a portion of our outstanding obligations.

We also incur obligations in connection with the operations of our subsidiaries and affiliates that do not appear on our balance sheet. These obligations take the form of guarantees, letters of credit and contractual commitments, as described under the Liquidity, Capital Resources sections of the Management’s Discussion & Analysis.

Financial market conditions could limit our access to capital and increase our costs of borrowing or refinancing, or have other adverse effects on our results.

TECO Finance and TEC have debt maturing in 2015 and subsequent years which they may need to refinance. Future financial market conditions could limit our ability to raise the capital we need and could increase our interest costs, which could reduce earnings. If we are not able to issue new debt, or we issue debt at interest rates higher than we expect, our financial results or condition could be adversely affected.

We enter into derivative transactions, primarily with financial institutions as counterparties. Financial market turmoil could lead to a sudden decline in credit quality among these counterparties, which could make in-the-money positions uncollectable.

We enter into derivative transactions with counterparties, most of which are financial institutions, to hedge our exposure to commodity price and interest rate changes. Although we believe we have appropriate credit policies in place to manage the non-performance risk associated with these transactions, turmoil in the financial markets could lead to a sudden decline in credit quality among these counterparties. If such a decline occurs for a counterparty with which we have an in-the-money position, we could be unable to collect from such counterparty.

Declines in the financial markets or in interest rates used to determine benefit obligations could increase our pension expense or the required cash contributions to maintain required levels of funding for our plan.

Under calculation requirements of the Pension Protection Act, as of the Jan. 1, 2015 measurement date, our pension plan was essentially fully funded. Under MAP 21, we are not required to make additional cash contributions over the next five years; however we may make additional cash contributions from time to time. Any future declines in the financial markets or further declines in interest rates could increase the amount of contributions required to fund our pension plan in the future, and could cause pension expense to increase.

Our financial condition and results could be adversely affected if our capital expenditures are greater than forecast.

We are forecasting capital expenditures at Tampa Electric to support the current levels of customer growth, to comply with the design changes mandated by the FPSC to harden transmission and distribution facilities against hurricane damage, to maintain transmission and distribution system reliability, to maintain coal-fired generating unit reliability and efficiency, and to add generating capacity at the Polk Power Station. We are forecasting capital expenditures at PGS to support customer growth, system reliability, conversion of customers from other fuels to natural gas and to replace bare steel and cast iron pipe. Forecasted capital expenditures at NMGC are expected to support customer and system reliability and expansion.

If our capital expenditures exceed the forecasted levels, we may need to draw on credit facilities or access the capital markets on unfavorable terms. We cannot be sure that we will be able to obtain additional financing, in which case our financial position could be adversely affected.

Our financial condition and ability to access capital may be materially adversely affected by multiple ratings downgrades to below investment grade, and we cannot be assured of any rating improvements in the future.

Our senior unsecured debt is rated as investment grade by S&P at BBB, by Moody's Investor's Services (Moody's) at Baa1, and by Fitch Ratings (Fitch) at BBB. The senior unsecured debt of TEC is rated by S&P at BBB+, by Moody's at A2 and by Fitch at A-. The senior unsecured debt of NMGC is rated by S&P at BBB+. A downgrade to below investment grade by the rating agencies, which would require a two-notch downgrade by S&P and Fitch, and a three notch downgrade by Moody's, may affect our ability to borrow, may change requirements for future collateral or margin postings, and may increase our financing costs, which may decrease our earnings. We may also experience greater interest expense than we may have otherwise if, in future periods, we replace maturing debt with new debt bearing higher interest rates due to any such downgrades. In addition, downgrades could adversely affect our relationships with customers and counterparties.

At current ratings, TEC and NMGC are able to purchase electricity and gas without providing collateral. If the ratings of TEC or NMGC decline to below investment grade, Tampa Electric, PGS or NMGC could be required to post collateral to support their purchases of electricity and gas.

We are a holding company with no business operations of our own and depend on cash flow from our subsidiaries to meet our obligations.

We are a holding company with no business operations of our own or material assets other than the stock of our subsidiaries. Accordingly, all of our operations are conducted by our subsidiaries. As a holding company, we require dividends and other payments from our subsidiaries to meet our cash requirements. If our subsidiaries are unable to pay us dividends or make other cash payments to us, we may be unable to pay dividends or satisfy our obligations.

TECO COAL

During the period of ownership prior to the completion of the sale of TECO Coal, we retain the risks of ownership of that business.

Any failure of the pending sale of TECO Coal would likely alter certain aspects of our current business plans and could adversely affect our business and the value of TECO Coal.

On Oct. 17, 2014, TECO Diversified entered into an agreement to sell all of its ownership interest in TECO Coal to Cambrian Coal Corp., and on Feb. 5, 2015 amended that agreement. The sale is subject to certain closing conditions, including the purchaser's obtaining suitable financing. In accordance with the terms of the amended securities purchase agreement, we expect to realize approximately $80 million in initial gross proceeds from the sale, plus contingent payments of up to $60 million over the next five years depending on specified coal benchmark prices. There can be no assurances that we will realize any additional proceeds from these potential contingent payments. If certain closing conditions are not met by March 13, 2015 , either party may choose not to proceed with the sale.

In anticipation of the pending sale transaction, we have presented the financial results of TECO Coal in this annual report as discontinued operations and included charges totaling $76.4 million after-tax to write-down the carrying value of TECO Coal to the estimated fair value of the business as of Dec. 31, 2014. In the event that the TECO Coal sale transaction is not consummated on the terms contemplated by the sale agreement or at all, our financial results could be adversely affected.

The coal markets continued to weaken in 2014 and it is likely that TECO Coal's operations will result in a loss in 2015. If the pending sale of TECO Coal is not consummated, TECO Coal's expected 2015 losses would have an adverse effect on TECO Energy's consolidated financial results and potentially our stock price. In addition, if the pending sale is not consummated, the value of TECO Coal's assets might be further impaired, and we may not be able to realize the proceeds expected from the current transaction in a subsequent sale transaction.

Below are additional risks associated with TECO Coal, which could impact our results in the event the sale is not completed.

Competition among coal producers in Central Appalachia and other producing regions, and low natural gas prices, may adversely affect TECO Coal's ability to sell steam coal. Low-cost natural gas has allowed utility steam coal users to switch from coal to natural gas to produce electricity, which has reduced the current market price and demand for TECO Coal's steam coal from domestic utilities. If we continue to own TECO Coal, continued or further declines in natural gas prices and increased competition from lower cost producing areas would keep demand and selling prices low, which would reduce TECO Coal's financial results, and could further reduce the value of its reserves.

TECO Coal has historically sold a significant portion of its production to domestic utilities for use in the generation of power. For over three years, natural gas prices have been dramatically lower than in previous periods due to the growth of hydraulic fracturing in the production of natural gas from shale formations. These low natural gas prices have caused utility coal users to switch to lower cost natural gas to generate electricity. Lower cost coals from other producing regions of the U.S., such as the Powder River Basin and the Illinois Basin are being utilized by more utilities in lieu of higher cost Central Appalachian coals, further reducing demand for TECO Coal's production.

In the current coal markets, prices for Central Appalachian steam coal are not profitable. Without an increase in the cost of natural gas and an increase in the use of coal for power generation, or a general improvement in coal market conditions, TECO Coal could sign coal sales contracts at lower than earnings break even or cash cost of production prices or production could be reduced, either of which would cause its financial results to be reduced. If these conditions were to persist or decline further, the value of TECO Coal's reserves could be further reduced, which could result in an additional non-cash impairment charge.

Failure to obtain the permits necessary to open new surface mines, or challenges to the validity of existing permits, could adversely affect TECO Coal's financial results.

Our surface coal mining operations are dependent on permits from the USACE to open new surface mines necessary to maintain or increase production. Since 2008, new permits issued by the USACE under Section 404 of the Clean Water Act for new surface coal mining operations have been challenged in court by various environmental groups, resulting in very few usable permits being issued. Failure to obtain the necessary permits to open new surface mines, which are required to maintain and expand production, could reduce production, cause higher mining costs or require purchasing coal at prices above our cost of production to fulfill contract requirements, which would adversely affect TECO Coal's financial results.

Challenges to existing permits that disrupt mining operations could result in higher costs if operations are forced to move to other mining sites or if coal is purchased from third parties, which would adversely affect TECO Coal's financial results.

In 2010, the EPA issued new guidelines related to water quality for Central Appalachian coal surface mining operations that would be conditions of new surface mine permits, which would add significant cost to operations or curtail our surface mining activities and preparation plant operations.

In 2010, the EPA issued new guidance on environmental permitting requirements for Central Appalachian mountaintop removal and other surface mining projects. This guidance, which was made final by the EPA in 2011, limits conductivity (level of mineral salts) in water discharges into streams from permitted areas, and was effective immediately on an interim basis. Because the EPA’s standards appear to be unachievable under most circumstances, surface mining activity could be substantially curtailed since most new and pending permits would likely be rejected. This guidance could also be extended to discharges from deep mines and preparation plants, which could result in a substantial curtailing of those activities as well. In 2012, the United States District Court for the District of Columbia ruled that the EPA had exceeded its statutory authority in establishing the water quality guidance discussed above. Following the outcome of this court decision, pending appeals by the EPA, few, if any, new usable permits have been issued by the USACE. Over time, if new permits are not issued, TECO Coal could incur higher production costs or reduced production from surface mining operations.

TECO Coal’s sales to international customers are subject to risks that could result in losses or increased costs.

TECO Coal is exposed to financial risk through its sales to international customers, primarily in Asia. TECO Coal attempts to mitigate this risk through the use of third parties to broker the sales, dollar-denominated contracts, passage of title upon loading in the U.S. port, customer responsibility for the international freight, letters of credit posted by customers for purchase price of the commodity and the transportation to the U.S. port, and the utilization of local agents where appropriate. TECO Coal cannot be assured that these measures will effectively mitigate all international risks, which could have an adverse effect on TECO Coal’s financial conditions.

In 2015, TECO Coal expects to continue to sell metallurgical coal to customers in Asia. Prices for metallurgical coal sales to Asia are subject to being reset each quarter based on levels of supply and demand in the region. Over the past three years, the quarterly prices have been lower due to increased supply from Australia and other suppliers and weakening demand for metallurgical coal from China. In the first quarter of 2015, prices are currently below levels that make sales to these markets profitable. If these quarterly prices persist, TECO Coal’s production and financial results could be adversely affected.

The U.S. federal government has proposed the elimination of the percentage depletion tax deduction for the mining of coal, and other hard minerals and fossil fuels which could result in an increase to our tax rate.

If the percentage depletion tax deduction is eliminated for TECO Coal, its effective tax rate would rise from the historical range of 20% to 25% to the general corporate tax rate of 37%, which would reduce financial results at TECO Coal.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES.

TECO Energy believes that the physical properties of its operating companies are adequate to carry on their businesses as currently conducted. The properties of Tampa Electric are subject to a first mortgage bond indenture under which no bonds are currently outstanding.

TAMPA ELECTRIC

Tampa Electric has three electric generating stations in service, with a December 2014 net winter generating capability of 4,703 MW. Tampa Electric assets include the Big Bend Power Station (1,607 MW capacity from four coal units and 61 MW from a CT), the Bayside Power Station (1,839 MW capacity from two natural gas combined cycle units and 244 MW from four CTs) and the Polk Power Station (220 MW capacity from the IGCC unit and 732 MW from four CTs).

The Big Bend coal-fired units went into service from 1970 to 1985, and the CT was installed in 2009. The Polk IGCC unit began commercial operation in 1996. Bayside Unit 1 was completed in April 2003, Unit 2 was completed in January 2004 and Units 3 through 6 were completed in 2009. In 2009, Tampa Electric placed the Phillips Power Station on long-term reserve standby. In July of 2012, Tampa Electric placed the City of Tampa Partnership Station on long-term reserve standby.

Tampa Electric owns 180 substations having an aggregate transformer capacity of 22,333 Mega Volts Amps. The transmission system consists of approximately 1,302 pole miles (including underground and double-circuit) of high voltage transmission lines, and the distribution system consists of 6,215 pole miles of overhead lines and 4,944 trench miles of underground lines. As of Dec. 31, 2014, there were 739,304 meters in service. All of this property is located in Florida.

All plants and important fixed assets are held in fee except that titles to some of the properties are subject to easements, leases, contracts, covenants and similar encumbrances and minor defects of a nature common to properties of the size and character of those of Tampa Electric.

Tampa Electric has easements or other property rights for rights-of-way adequate for the maintenance and operation of its electrical transmission and distribution lines that are not constructed upon public highways, roads and streets. It has the power of eminent domain under Florida law for the acquisition of any such ROW for the operation of transmission and distribution lines. Transmission and distribution lines located in public ways are maintained under franchises or permits.

TEC has a long-term lease for the office building in downtown Tampa, which serves as headquarters for TECO Energy, Tampa Electric and PGS.

PEOPLES GAS SYSTEM

PGS's distribution system extends throughout the areas it serves in Florida and consists of approximately 18,540 miles of pipe, including approximately 11,740 miles of mains and 6,800 miles of service lines. Mains and service lines are maintained under ROW, franchises or permits.

PGS's operations are located in 14 operating divisions throughout Florida. While most of the operations and administrative facilities are owned, a small number are leased.

NEW MEXICO GAS COMPANY

NMGC'S distribution system extends throughout the areas it serves in New Mexico and consists of approximately 11,800 miles of pipe, including approximately 1,600 miles of transmission pipeline and 10,200 miles of distribution lines. Mains and service lines are maintained under ROW, franchises or permits.

NMGC's operations are located in six operating areas throughout New Mexico. While most of the operations and administrative facilities are owned, a small number are leased.

TECO COAL

Property Control

Operations of TECO Coal and its subsidiaries are conducted on both owned and leased properties totaling approximately 294,000 acres in Kentucky, Tennessee and Virginia. TECO Coal's current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. As is typical in the coal mining industry, TECO Coal generally has not obtained title insurance in connection with its acquisitions of coal reserves and/or related surface properties. In many cases, the seller or lessor will grant the purchasing or leasing entity a warranty of property title. When leasing coal reserves and/or related surface properties where mining has previously occurred, TECO Coal may opt not to perform a separate title confirmation due to the previous mining activities on such a property. In cases involving less significant properties and consistent with industry practices, title and boundaries to less significant properties are now verified during lease or purchase negotiations.

In situations where property is controlled by lease, the lease terms are generally sufficient to allow the reserves for the associated operation to be mined within the initial lease term. The terms of many of these leases extend until the exhaustion of the mineable and merchantable coal from the leased property. If, however, extensions of the original lease term become necessary, provisions have generally been made within the original lease to extend the lease term upon continued payment of minimum royalties.

Coal Reserves

As of Dec. 31, 2014, the TECO Coal operating companies had a combined estimated 290.0 million tons of proven and probable recoverable reserves. All of the reserves consist of high quality bituminous coal. Reserves are the portion of the proven and probable tonnage that meet TECO Coal’s economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels. Additionally, other controlled areas presently identified as resource total 69.3 million tons of coal.

Reserves are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and probable coal reserves are defined by SEC Industry Guide 7 as follows:

Proven (Measured) Reserves - Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, working or drill holes: grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

Probable (Indicated) Reserves - Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but for which the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

Drill hole spacing for confidence levels in reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). In this method of classification, “proven” reserves are considered to be those lying within one-quarter mile (1,320 feet) of a valid point of measurement and “probable” reserves are those lying between one-quarter mile and three-quarters mile (3,960 feet) from such an observation point.

Reserve estimates are prepared by TECO Coal’s staff of geologists. There are two chief geologists with the responsibility to track changes in reserve estimates, supervise TECO Coal’s other geologists and coordinate third-party reviews of reserve estimates by qualified mining consultants. Annually, a third-party reserve audit is performed by Cardno, Inc. on TECO Coal’s newly identified reserves. The results of that audit are reflected in the numbers within this report.

The following table (Table 4) shows recoverable reserves by quantity and the method of property control as well as the Assigned and Unassigned reserves per mining complex.

RECOVERABLE RESERVES BY QUANTITY (1)

(Millions of tons)

Table 4

							Assigned (2)		Unassigned (2)	
Mining Complex	Location	Total	Proven	Probable	Owned	Leased	2015	2014	2015	2014
Gatliff Coal	Bell County, KY/ Knox County, KY/ Campbell County, TN	3.4	3.0	0.4	1.2	2.2	0.5	0.5	2.9	2.9
Clintwood Elkhorn Mining	Pike County, KY/ Buchanan County, VA	53.4	44.6	8.8	0.0	53.4	53.4	55.2	0.0	0.0
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	99.4	58.9	40.5	81.5	17.9	48.4	52.9	51.0	51.0

Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	133.8	85.6	48.2	1.3	132.5	128.6	130.5	5.2	5.2
Totals:		290.0	192.1	97.9	84.0	206.0	230.9	239.1	59.1	59.1

Notes:

(1) Recoverable reserves represent the amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods under current law. Reserve information reflects a moisture factor of 6.5%, which represents the average moisture present in TECO Coal’s delivered coal.

(2) Assigned reserves mean coal which has been committed by TECO Coal to operating mine shafts, mining equipment, and plant facilities, and all coal which has been leased by TECO Coal to others. Unassigned reserves represent coal which has not been committed, and which would require new mineshafts, mining equipment, or plant facilities before operations could begin on the property.

29

RECOVERABLE RESERVES BY QUALITY (1)

(Millions of tons)

Table 5

Mining Complex	Recoverable Reserves	Sulfur Content < 1% (2)	>1% (2)	Compliance Tons (3)	Average BTU As received	Coal Type (4)
Gatliff Coal	3.4	3.2	0.2	0.0	12,000-13,100	LSU
Clintwood Elkhorn Mining	53.4	35.1	18.3	13.8	12,500-13,500	HVM, LSU, PCI
Premier Elkhorn Coal	99.4	84.0	15.4	56.6	12,700-13,100	HVM, IS, LSU, PCI
Perry County Coal	133.8	104.3	29.5	81.1	12,500-13,100	LSU, PCI, V
Totals:	290.0	226.6	63.4	151.5		

Notes:

(1) Reserve information reflects a moisture factor of 6.5%. This moisture factor represents the average moisture present in TECO Coal's delivered coal.
(2) <1% or >1% refers to sulfur content as a percentage in coal by weight.
(3) Compliance coal is any coal that emits less than 1.2 pounds of sulfur dioxide per million BTU when burned. Compliance coal meets sulfur emission standards imposed by Title IV of the Clean Air Act.
(4) Reserve holdings include metallurgical, PCI and thermal coal reserves. Although metallurgical and PCI coal reserves receive the highest selling price in the current market when marketed to steel-making customers, they can also be marketed as an ultra-high BTU, low-sulfur utility coal for electricity generation.

HVM – High Vol Metallurgical

PCI – Pulverized Coal Injection

LSU – Low Sulfur Utility

V – Various

IS – Industrial Stoker

Market Allocation of Reserves

The table below shows the allocation of TECO Coal reserves by market category (metallurgical, PCI, and thermal coal), which was prepared by TECO Coal at its four operating subsidiaries. As shown below, a substantial portion of the Clintwood Elkhorn Mining coal reserves has been allocated to the metallurgical category (with the remainder to the thermal coal category), a substantial portion of the Premier Elkhorn Coal reserves has been allocated to the PCI and metallurgical categories (with the remainder to the thermal coal category), a substantial portion of the Perry County coal reserves has been allocated to the PCI category (with the remainder to the thermal coal category), and all of the Gatliff Coal reserves has been allocated to the thermal coal category.

At TECO Coal's request, Cardno, Inc. completed an audit of the methodology used by TECO Coal to conduct such allocation of its coal tonnage estimates. Cardno, Inc. reviewed information provided by TECO Coal and TECO Coal's methodology of processing, which included examination by certified professional geologists of all supplied coal deposit maps and supporting coal quality data using industry accepted standards. The audit performed by Cardno, Inc. concluded that TECO Coal's methodology of allocating its demonstrated reserves by market category is reasonably and responsibly prepared in accordance with industry accepted standards and in general conformance with SEC Industry Guide 7.

Market conditions may not always permit sales of coal into the particular market as identified; however, the objective of this reserve allocation is to recognize the market potential for planning and investment purposes.

The following table (Table 6) shows the recoverable reserves by market category per mining complex and in total. The total reserve mix is defined by percentage as 40% metallurgical, 40% PCI, (for a combined 80% specialty coals) and 20% thermal coal.

RESERVES BY MARKET CATEGORY

Table 6

	Met			PCI			Thermal			Grand
Mining Complex	Reserves			Reserves			Reserves			Totals
	Proven	Probable	Total	Proven	Probable	Total	Proven	Probable	Total	
Gatliff Coal	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.6	3.4	3.4
Clintwood Elkhorn Mining	39.8	8.1	47.9	0.0	0.0	0.0	0.0	5.5	5.5	53.4
Premier Elkhorn Coal	33.4	36.0	69.4	10.8	2.0	12.8	14.7	2.5	17.2	99.4
Perry County Coal	0.0	0.0	0.0	66.0	38.5	104.5	19.6	9.7	29.3	133.8
Totals:	73.2	44.1	117.3	76.8	40.5	117.3	37.1	18.3	55.4	290.0
% of Totals:			40.0 %			40.0 %			20.0%	

Reserve Estimation Procedure

TECO Coal's reserves are based on over 3,800 data points, including drill holes, prospect measurements and mine measurements. Reserve estimates also include information obtained from on-going exploration drilling and in-mine channel sampling programs. Reserve classification is determined by evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect fluctuations in the economics in the market and/or changes in engineering parameters and/or geologic conditions. Additionally, the information is constantly being updated to reflect new data for existing property as well as new acquisitions and depleted reserves.

This data may include elevation, thickness, and where samples are available, the quality of the coal from individual drill holes and channel samples. The information is assembled by geologists and engineers at TECO Coal, and is computer modeled from which preliminary reserve estimations are generated. The information derived from the geological database is then combined with data on ownership or control of the mineral and surface interests to determine the extent of the reserves in a given area. Determinations of reserves are made after in-house geologists have reviewed the computer generated models and enhanced the grid models to better reflect regional trends.

During TECO Coal's reserve evaluation and mine planning, TECO Coal takes into account factors such as restrictions under railroads, roads, buildings, power lines, or other structures. Depending on these factors, coal recovery may be limited or, in some instances, entirely prohibited. Current engineering practices are used to determine potential subsidence zones. The footprint of the relevant structure, as well as a safety angle-of-draw, is considered when mining near or under such facilities. Also, as part of TECO Coal's reserve and mineability evaluation, TECO Coal reviews legal, economic and other technical factors. Final review and recoverable reserve determination is completed after a thorough analysis by in-house engineers, geologists and finance associates.

Item 3. LEGAL PROCEEDINGS.

From time to time, TECO Energy and its subsidiaries are involved in legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with accounting standards for contingencies to provide for matters that are probable of resulting in an estimable loss. While the outcome of such proceedings is uncertain, management does not believe that their ultimate resolution will have a material adverse effect on the company's results of operations, financial condition, or cash flows.

For a discussion of certain legal proceedings and environmental matters, including an update of previously disclosed legal proceedings and environmental matters, see Notes 12 and 9, Commitments and Contingencies, of the TECO Energy and Tampa Electric Company Consolidated Financial Statements, respectively.

Item 4. MINE SAFETY DISCLOSURES.

TECO Coal is subject to regulation by the MSHA under the Federal Mine Safety and Health Act of 1977 (the Mine Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this annual report.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The following table shows the high and low sale prices for shares of TECO Energy common stock, which is listed on the New York Stock Exchange, and dividends paid per share, per quarter.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2014				
High	$ 17.31	$ 18.53	$ 18.48	$ 21.29
Low	16.12	16.90	16.91	17.35
Close	17.15	18.48	17.38	20.49
Dividend	$ 0.22	$ 0.22	$ 0.22	$ 0.22
2013				
High	$ 17.87	$ 19.22	$ 17.99	$ 17.75
Low	16.71	16.40	16.15	16.40
Close	17.82	17.19	16.54	17.24
Dividend	$ 0.22	$ 0.22	$ 0.22	$ 0.22

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 13, 2015 was 10,844.

Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends to its common shareholders are dividends and other distributions from its operating companies.

See Liquidity, Capital Resources – Covenants in Financing Agreements section of MD&A, and Notes 6, 7 and 12 to the TECO Energy Consolidated Financial Statements for additional information regarding significant financial covenants.

All of TEC's common stock is owned by TECO Energy and, therefore, there is no market for the stock. TEC pays dividends on its common stock substantially equal to its net income. Such dividends totaled $262.6 million in 2014, $222.1 million in 2013 and $228.3 million in 2012.

Set forth below is a table showing shares of TECO Energy common stock deemed repurchased by the issuer.

	Total Number of Shares (or Units)	Average Price Paid per Share	Total Number of Shares (or Units)	Maximum Number (or Approximate

	Purchased (1)	(or Unit)	Purchased as Part of Publicly Announced Plans or Programs	Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
Oct. 1, 2014 – Oct. 31, 2014	994	$ 18.85	0.0	0.0
Nov. 1, 2014 – Nov. 30, 2014	6,075	$ 19.82	0.0	0.0
Dec. 1, 2014 – Dec. 31, 2014	695	$ 20.33	0.0	0.0
Total 4th Quarter 2014	7,764	$ 19.74	0.0	0.0

(1) These shares were not repurchased through a publicly announced plan or program, but rather relate to compensation or retirement plans of the company. Specifically, these shares represent shares delivered in satisfaction of the exercise price and/or tax withholding obligations by holders of stock options who exercised options (granted under TECO Energy's incentive compensation plans), shares delivered or withheld (under the terms of grants under TECO Energy's incentive compensation plans) to offset tax withholding obligations associated with the vesting of restricted shares and shares purchased by the TECO Energy Group Retirement Savings Plan pursuant to directions from plan participants or dividend reinvestment.

Shareholder Return Performance Graph

The following graph shows the cumulative total shareholder return on TECO Energy's common stock on a yearly basis over the five-year period ended Dec. 31, 2014, and compares this return with that of the S&P 500 Index, the S&P Multi Utility Index and the Dow Jones U.S. Coal Index. The graph assumes that the value of the investment in TECO Energy's common stock and each index was $100 on Dec. 31, 2009 and that all dividends were reinvested.

Item 6. SELECTED FINANCIAL DATA OF TECO ENERGY

(millions, except per share amounts)

Years ended Dec. 31,	2014	2013	2012	2011	2010
Revenues [(1)]	$2,566.4	$2,355.1	$2,387.7	$2,476.9	$2,673.5
Net income from continuing operations [(1)]	206.4	188.7	197.0	200.6	159.9
Net income from discontinued operations attributable to TECO Energy [(1)]	(76.0)	9.0	15.7	72.0	79.1
Net income attributable to TECO Energy	130.4	197.7	212.7	272.6	239.0
Total assets	8,726.2	7,448.0	7,334.9	7,307.2	7,270.9
Long-term debt, including current portion	3,628.5	2,921.1	2,972.7	3,073.4	3,226.4
EPS – Basic					
From continuing operations [(1)]	$0.92	$0.88	$0.92	$0.93	$0.75
From discontinued operations attributable to TECO Energy [(1)]	(0.34)	0.04	0.07	0.34	0.37
Attributable to TECO Energy	$0.58	$0.92	$0.99	$1.27	$1.12
EPS – Diluted					
From continuing operations [(1)]	$0.92	$0.88	$0.92	$0.93	$0.74
From discontinued operations attributable to TECO Energy [(1)]	(0.34)	0.04	0.07	0.34	0.37
Attributable to TECO Energy	$0.58	$0.92	$0.99	$1.27	$1.11
Dividends paid per common share outstanding	$0.880	$0.880	$0.880	$0.850	$0.815

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in Note 19 to the TECO Energy Consolidated Financial Statements.

Item 7.

MANAGEMENT'S DISCUSSION & ANALYSIS

OF FINANCIAL CONDITIONS & RESULTS OF OPERATIONS

This Management's Discussion & Analysis contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. Actual results may differ materially from those forecasted. Such statements are based on our current expectations as of the date we filed this report, and we do not undertake to update or revise such forward-looking statements, except as may be required by law. These forward-looking statements include references to our anticipated capital expenditures, liquidity and financing requirements, projected operating results, future environmental matters, and regulatory and other plans. Important factors that could cause actual results to differ materially from those projected in these forward-looking statements are discussed under "Risk Factors, and elsewhere in this MD&A."

TECO Energy, Inc. is a holding company, and all of its business is conducted through its subsidiaries. In this Management's Discussion & Analysis, "we," "our," "ours" and "us" refer to TECO Energy, Inc. and its consolidated group of companies, unless the context otherwise requires.

OVERVIEW

We are a utility holding company with regulated electric and gas utility operations in Florida and New Mexico.

Our largest subsidiary, Tampa Electric Company, includes regulated electric and gas utility operations in Florida. Tampa Electric serves more than 706,000 retail customers in a 2,000-square-mile service area in West Central Florida and has electric generating plants with a winter peak generating capacity of 4,668 MW. PGS, Florida's largest gas distribution utility, serves almost 354,000 residential, commercial, industrial and electric power generating customers in all major metropolitan areas of the state, with a total natural gas throughput of more than 1.5 billion therms in 2014.

NMGC, our other utility subsidiary, is New Mexico's largest regulated natural gas distribution utility and serves almost 513,000, primarily residential customers in 23 of New Mexico's 33 counties, with total natural gas throughput of 275 million therms in the four month ownership period in 2014.

We also own TECO Coal, which through its subsidiaries produces thermal coal for use by utilities and metallurgical coal for use by the steel industry from Central Appalachian underground and surface mines. In October 2014, we announced that we had entered into an agreement to sell TECO Coal and its subsidiaries to Cambrian Coal Co., a member of the Booth Energy group. In February 2015, the agreement was amended to lower the sales price and extend the closing date. The revised total sales price of $140 million includes future contingent consideration of $60 million if Asian metallurgical coal benchmark prices reach certain levels over the next five years. The $80 million base cash purchase price is subject to normal conditions and to adjustments at closing, including the purchaser obtaining financing. Upon closing of the sale, we will have completed the process of returning TECO Energy to its roots as a regulated utility. As a result of our Board of Directors authorizing us to enter into negotiations for the sale of TECO Coal, effective in the third quarter it was classified as asset held for sale and its results for all periods presented are classified as discontinued operations. TECO Energy recorded a non-cash valuation adjustment of approximately $76 million, after tax, to the carrying value of TECO Coal to reflect the sales price. We expect to use sale proceeds to repay short-term debt and for general corporate purposes. (See the Discontinued Operations section later in this MD&A.)

In 2012, we sold our ownership interest in TECO Guatemala, which, through its subsidiaries, owned a coal-fired generating facility and a 96% ownership interest in an oil-fired peaking power generating plant, both in Guatemala.

NEW MEXICO GAS CO.

On Aug. 13, 2014, the NMPRC unanimously approved TECO Energy's acquisition of NMGC, and the transaction closed on Sept. 2, 2014.

With the addition of NMGC's almost 513,000 gas customers, TECO Energy utility subsidiaries now serve almost 870,000 gas distribution customers in two states, and almost 1.6 million regulated electric and gas customers in Florida and New Mexico.

The aggregate purchase price for the acquisition was $950 million, which included the assumption of $200 million of existing debt. The transaction was financed through cash on hand at TECO Energy parent, proceeds from the issuance of $292 million of TECO Energy common stock, the issuance of $270 million of private placement debt at NMGI and NMGC, which was used to retire $219 million of existing NMGC and NMGI debt, and short-term borrowings at TECO Finance.

Strategic benefits of the acquisition include:

- A transformative transaction that immediately added almost 513,000 customers in a single state.
- Provides an opportunity for TECO Energy's experienced management team to share marketing expertise in a new and growing service territory, and for both companies to share best practices to support growth.
- Diversifies TECO Energy's operating footprint.
- Provides immediate to near-term shareholder and customer benefits through organic growth opportunities.
- Accretive to fourth quarter 2014 earnings and expected to be accretive to full-year earnings in 2015.

2014 PERFORMANCE

All amounts included in this MD&A are after tax, unless otherwise noted.

In 2014, our net income attributable to TECO Energy was $130.4 million, or $0.58 per share, compared with $197.7 million, or $0.92 per share, in 2013. In 2014, net income from continuing operations was $206.4 million, or $0.92 per share, compared with $188.7 million, or $0.88 per share, in 2013. The $76.0 million loss from discontinued operations in 2014 includes the operating results from TECO Coal, impairment and valuation charges totaling $76.4 million and items related to the 2012 sale of TECO Guatemala. The $9.0 million net income from discontinued operations in 2013 reflects TECO Coal operating results.

In 2014 and 2013, non-GAAP results from continuing operations, which exclude $23.3 million and $6.2 million of charges, respectively, were $229.7 million, or $1.03 on a per-share basis, compared with $194.9 million, or $0.91 on a per-share basis. See the 2014 and 2013 GAAP – Non-GAAP Reconciliation Table below. There were no charges or gains to cause non-GAAP results to differ from net income in 2012.

The most significant factors impacting the year-over-year-comparison of non-GAAP results were the almost $50 million of higher pretax base revenue at Tampa Electric as a result of its 2013 rate case settlement, and the addition of NMGC. Tampa Electric and PGS benefited from customer growth of 1.6% and 1.9%, respectively.

In 2013, net income was $197.7 million, or $0.92 per share, compared with $212.7 million, or $0.99 per share, in 2012. The 2013 full-year net income from continuing operations was $188.7 million, or $0.88 per share, compared with $197.0 million, or $0.92 per share, in 2012. The 2013 net income from discontinued operations, which includes operating results from TECO Coal, was $9.0 million, or $0.04 per share, compared with net income of $15.7 million, or $0.07 per share, in 2012.

OUTLOOK

Our outlook for 2015 reflects our expectation that all of our utilities will deliver strong earnings growth, that the Florida utilities will earn returns above the middle of their allowed ROE ranges, and that NMGC earnings will be accretive to TECO Energy in 2015. The drivers impacting 2015 are summarized below and discussed in further detail in the individual operating company sections.

Tampa Electric expects to earn in the upper half of its allowed ROE range of 9.25% to 11.25%, driven by $7.5 million of higher base revenues that were effective Nov. 1, 2014 as a result of its September 2013 rate case settlement agreement, average customer growth trends in line with those experienced in 2014 and higher AFUDC. Retail energy sales to residential, commercial and non-phosphate industrial customers are expected to grow by almost 1.0%. Total retail sales are expected to be about 0.3% higher, as sales to lower-margin interruptible Industrial-Phosphate customers are expected to decline due to increased self-generation. These sales forecasts reflect the impact of improved lighting and appliance efficiency and customer energy conservation. Full-year O&M expense are expected to be lower than 2014 as lower employee-related costs and the impact of synergies in Florida due to the NMGC integration, are expected to more than offset higher costs to operate and maintain the system and to reliably serve customers. Depreciation expense is expected to be higher due to normal additions to facilities to serve customers.

PGS expects to continue to earn in the upper half of its allowed ROE range of 9.75% to 11.75% from average customer growth trends in line with those experienced in 2014 and continued interest from customers utilizing petroleum and other fuel sources to convert to natural gas. O&M expense and depreciation trends are expected to be similar to Tampa Electric.

NMGC expects 2015 customer growth of more than 0.5%, volume growth at about the same level, and lower O&M expense due to integration synergies. Consistent with the terms of the NMPRC approval of the acquisition, NMGC will credit $2.0 million to customer bills in the first 12 months post-closing and $4.0 million in each subsequent 12-month period until new base rates are established. NMGC is expected to be accretive to TECO Energy's earnings per share in 2015.

These forecasts are based on our current assumptions described in each operating company discussion, which are subject to risks and uncertainties (see the Risk Factors section).

Our priority for the use of cash is investment in our utilities to support their capital spending programs while maintaining their capital structures and financial integrity, and over time reduction of parent debt. In 2015, we expect to make additional equity contributions to Tampa Electric and to PGS of approximately $150 million and $25 million, respectively. We anticipate capital spending at the Florida utilities in 2015 to be at comparable levels to 2014 at approximately $675 million, including the investments in generating capacity additions at Tampa Electric and opportunities to grow the PGS system described below. We expect NMGC capital expenditures of approximately $60 million to support modest customer growth and system reliability (see the Liquidity, Capital Resources section).

We have evaluated trends, strategies and opportunities affecting our regulated utilities, to sharpen the focus on developing longer-range plans to take advantage of emerging growth opportunities and some fundamental changes in our industry. Over time, we expect these initiatives to contribute to organic earnings growth. Some of the areas that we are currently focused on include:

- We believe there are opportunities to grow the use of CNG for fleet vehicles. In 2013, the Florida legislature enacted legislation supportive of CNG vehicle conversions through rebates and tax incentives. To date, we have had success working with fleet owners to install 31 CNG filling stations with completed conversions of more than 1,000 vehicles of various sizes to CNG. In 2015, the number of vehicles already converted or committed to conversion will consume almost 20 million therms annually, the equivalent consumption of more than 75,000 typical Florida residential customers. Such conversions offer compelling economics to customers, even in a low oil price environment, and expand PGS therm sales without significant capital investment by PGS.
- We are taking the first steps necessary, through our Customer Relationship Management software project, to implement Smart Grid applications that use proven technology and offer operating and financial benefits to our customers and overall operations. These include, among other opportunities, transitioning automatic meter reading technology to advanced metering infrastructure, which would include a significant investment in our communications infrastructure but would result in O&M savings.
- We recognize that there is a growing demand for natural-gas-fired power generation in Florida over the next decade. We project that Florida may need between 0.8 billion and 1.25 billion cubic feet per day (Bcf/day) by as early as 2016. Given our expertise in this area, we continue to evaluate opportunities to partner with transmission and end-use natural gas customers.
- In 2014, we announced plans for a 2 MW solar energy installation at Tampa International Airport that we will own and operate. We anticipate developing additional similar sized solar photo-voltaic installations and potentially utility scale installations.

At PGS, the business model for system expansion evolved over the past several years to focus on extending the system to serve large commercial and industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future make it attractive for these customers to convert from fuels that are currently more expensive on a cost per MMBTU basis.

Previously, during periods of robust residential growth, PGS extended its system to serve large residential housing developments, and commercial growth followed the residential development. In recent years, when fewer large residential projects were developed, commercial and industrial-led expansion has allowed PGS to continue to provide clean and economical natural gas to areas of the state previously unserved and to be positioned to serve future residential growth.

We are expanding marketing activities at NMGC, deploying the marketing skills developed by PGS in Florida to New Mexico to grow that business. Areas of focus include conversion of large commercial or industrial customers using petroleum based fuels to natural gas, developing the CNG market for vehicle fleets in New Mexico as PGS has successfully done in Florida, and support of economic development in New Mexico.

In addition to the organic growth opportunities within our current portfolio of utilities, we may consider opportunities for growth through acquisitions, as we did in the 2014 purchase of NMGC.

RESULTS SUMMARY

The table below compares our GAAP net income to our non-GAAP results. A reconciliation between GAAP net income and non-GAAP results is contained in the Reconciliation of GAAP net income from continuing operations to non-GAAP results tables for 2014 and 2013. A non-GAAP financial measure is a numerical measure that includes or excludes amounts, or is subject to adjustments that have the effect of including or excluding amounts that are excluded or included from the most directly comparable GAAP measure (see the Non-GAAP Information section).

Results Comparisons

(millions)	2014	2013	2012
Net income attributable to TECO Energy	$130.4	$197.7	$212.7
Net income from continuing operations	$206.4	$188.7	$197.0
Non-GAAP results from continuing operations	$229.7	$194.9	$197.0

The table below provides a summary of revenues, earnings per share, net income and shares outstanding for the 2014-2012 period.

Earnings Summary

(millions) Except per-share amounts	2014			2013		2012	
Consolidated revenues	$	2,566.4		$	2,355.1	$	2,387.7
Earnings per share – basic							
Earnings per share attributable to TECO Energy	$	0.58		$	0.92	$	0.99
Earnings (loss) per share from discontinued operations		(0.34	)		0.04		0.07
Earnings per share attributable to TECO Energy before discontinued operations	$	0.92		$	0.88	$	0.92
Earnings per share – diluted							
Earnings per share attributable to TECO Energy	$	0.58		$	0.92	$	0.99
Earnings (loss) per share from discontinued operations		(0.34	)		0.04		0.07

Earnings per share attributable to TECO Energy before discontinued operations	$	0.92		$	0.88		$	0.92
Net income attributable to TECO Energy	$	130.4		$	197.7		$	212.7
Net income (loss) from discontinued operations		(76.0	)		9.0			15.7
Charges and (gains)[1]		23.3			6.2			0.0
Non-GAAP results	$	229.7		$	194.9		$	197.0
Average common shares outstanding (millions)								
Basic		223.1			215.0			214.3
Diluted		223.7			215.5			215.0

(1) See the GAAP to non-GAAP reconciliation table that follows.

The following tables show the specific adjustments made to GAAP net income for each segment to develop our 2014 and 2013 non-GAAP results.

2014 Reconciliation of GAAP Net Income to Non-GAAP Results

Net income impact (millions)	Tampa Electric	PGS	NMGC	TECO Coal [(1)]	Other (net) [(1)]	Total
GAAP net income attributable to TECO Energy	$224.5	$35.8	$10.5	$(82.0)	$(58.4)	$130.4
Net income (loss) from discontinued operations	0.0	0.0	0.0	(82.0)	6.0	(76.0)
Net income (loss) from continued operations	224.5	35.8	10.5	0.0	(64.4)	206.4
Costs associated with the acquisition of NMGC	0.0	0.0	0.0	0.0	16.6	16.6
Consolidated deferred tax balance adjustment	0.0	0.0	0.0	0.0	6.7	6.7
Total charges and (gains)	0.0	0.0	0.0	0.0	23.3	23.3
Non-GAAP results	$224.5	$35.8	$10.5	$0.0	$(41.1)	$229.7

2013 Reconciliation of GAAP Net Income to Non-GAAP Results

Net income impact (millions)	Tampa Electric	PGS	NMGC	TECO Coal [(1)]	Other (net) [(1)]	Total
GAAP net income attributable to TECO Energy	$190.9	$34.7	$0.0	$9.0	$(36.9)	$197.7
Net income (loss) from discontinued operations	0.0	0.0	0.0	9.0	0.0	9.0
Net income (loss) from continued operations	190.9	34.7	0.0	0.0	(36.9)	188.7
Costs associated with the acquisition of NMGC	0.0	0.0	0.0	0.0	6.2	6.2
Total charges	0.0	0.0	0.0	0.0	6.2	6.2
Non-GAAP results	$190.9	$34.7	$0.0	$0.0	$(30.7)	$194.9

(1) TECO Coal results and other certain costs previously included in Other (net) have been recast to Discontinued Operations.

NON-GAAP INFORMATION

From time to time, in this MD&A, we provide non-GAAP results, which present financial results after elimination of the effects of certain identified charges and gains. We believe that it is helpful to present a non-GAAP measure of performance that clearly reflects the ongoing operations of our business and allows investors to better understand and evaluate the business as it is expected to operate in future periods. Management and the board of directors use this non-GAAP presentation as a yardstick for measuring our performance, making decisions that are dependent upon the profitability of our various operating units and determining levels of incentive compensation.

The non-GAAP measure of financial performance we use is not a measure of performance under accounting principles generally accepted in the United States and should not be considered an alternative to net income or other GAAP figures as an indicator of our financial performance or liquidity. Our non-GAAP presentation of results may not be comparable to similarly titled measures used by other companies.

While none of the particular excluded items are expected to recur, there may be adjustments to previously estimated gains or losses related to the disposition of assets or additional debt extinguishment activities. We recognize that there may be items that could be excluded in the future. Even though charges may occur, we believe the non-GAAP measure is important in addition to GAAP net income for assessing our potential future performance, because excluded items are limited to those that we believe are not indicative of future performance.

OPERATING RESULTS

This MD&A utilizes TECO Energy's consolidated financial statements, which have been prepared in accordance with GAAP, and separate non-GAAP measures to analyze the financial condition of the company. Our reported operating results are affected by a number of critical accounting estimates such as those involved in our accounting for regulated activities, asset impairment testing and others (see the Critical Accounting Policies and Estimates section).

The following table shows the segment revenues, net income and earnings per share contributions from continuing operations of our business segments on a GAAP basis (see Note 14 to the TECO Energy Consolidated Financial Statements).

(millions) Except per share amounts		2014	2013	2012
Segment revenues [1]				
	Tampa Electric	$2,021.0	$1,950.5	$1,981.3
	PGS	399.6	393.5	398.9
	NMGC	137.5	0.0	0.0
Total utility companies		$2,558.1	$2,344.0	$2,380.2
Net income [2]				
	Tampa Electric	$224.5	$190.9	$193.1
	PGS	35.8	34.7	34.1
	NMGC	10.5	0.0	0.0
Total utility companies		270.8	225.6	227.2
	Other (net) [4]	(64.4)	(36.9)	(30.2)
Net income from continuing operations [4]		206.4	188.7	197.0
Net income (loss) from discontinued operations [2]		(76.0)	9.0	15.7
Net income attributable to TECO Energy		$130.4	$197.7	$212.7
Earnings per share - basic [3]				
	Tampa Electric	$1.00	$0.89	$0.90
	PGS	0.16	0.16	0.16
	NMGC	0.05	0.0	0.0
Total utility companies		1.21	1.05	1.06
	Other (net) [4]	(0.29)	(0.17)	(0.14)
Earnings per share from continuing operations		0.92	0.88	0.92
Earnings (loss) per share from discontinued operations [2]		(0.34)	0.04	0.07
Earnings per share attributable to TECO Energy		$0.58	$0.92	$0.99
Average shares outstanding – basic		223.1	215.0	214.3

(1) Segment revenues include intercompany transactions that are eliminated in the preparation of TECO Energy's consolidated financial statements.

(2) Prior to its classification as Asset Held for Sale, the TECO Coal segment net income and earnings per share included in discontinued operations were reported on a basis that includes internally allocated pretax interest costs of $3.0 million through June 2014, and $6.4 million and $6.8 million in 2013 and 2012, respectively. Internally allocated interest costs were at a pretax interest rate of 6.00% for 2014, 2013 and 2012.

(3) The number of shares used in the earnings-per-share calculations is basic shares.

(4) Net income from continuing operations including charges of $23.3 million in 2014 and $6.2 million in 2013.

TAMPA ELECTRIC

Electric Operations Results

Net income in 2014 was $224.5 million, compared with $190.9 million in 2013, driven primarily by the benefits from the 2013 rate case settlement, higher energy sales from average customer growth trends in line with those experienced in 2013, a stronger economy, and lower O&M. Net income in 2014 included $10.5 million of AFUDC equity, which represents allowed equity cost capitalized to construction costs, compared with $6.3 million in 2013. These items were partially offset by higher depreciation expense, and $2.9 million lower earnings on assets recovered through the ECRC.

In 2014, total degree days in Tampa Electric's service area were 4% below normal, and 3% below 2013 levels, driven by milder fourth quarter weather. Pretax base revenue included almost $50 million of higher revenue as a result of the 2013 rate case settlement. In 2014, total net energy for load, which is a calendar measurement of retail energy sales rather than a billing-cycle measurement, was 0.7% higher than in 2013, driven by customer growth. Sales to lower-margin, industrial-phosphate customers were lower as self-generation by these customers increased. The energy sales shown in the summary table below reflect the energy sales based on the timing of billing cycles, which can vary from period to period.

O&M expense, excluding all FPSC-approved cost-recovery clauses, decreased $1.0 million in 2014, reflecting lower employee-related costs, including pension expense, and the elimination of the storm damage reserve accrual, partially offset by higher costs to operate and maintain the system. Compared to 2013, depreciation and amortization expense increased $6.0 million, reflecting additions to facilities to serve customers.

Net income in 2013 was $190.9 million, compared with $193.1 million in 2012. Results in 2013 reflected 1.5% customer growth, higher base revenues effective Nov. 1, 2013, as a result of the rate case settlement, and energy sales, weather and customer usage patterns similar to 2012. Higher O&M was partially offset by lower interest expense. Net income included $6.3 million of AFUDC-equity compared with $2.6 million in 2012. Net income also reflected $3.6 million lower earnings on assets recovered through the ECRC due to an FPSC rule revising the return on investment calculation effective Jan. 1, 2013.

In 2013, total degree days in Tampa Electric's service area were 1% below normal, and 1% below the prior year, reflecting generally milder weather early in the year. Pretax base revenues were $13 million higher than in 2012, primarily due to $10 million of higher base rates effective Nov. 1, 2013, and higher energy sales late in the year due to unusually warm early winter weather. Total net energy for load decreased 0.4% in 2013 compared with 2012.

O&M expense, excluding all FPSC-approved cost-recovery clauses, increased $19.4 million in 2013, reflecting $8.2 million of higher accruals for performance-based incentive compensation for all employees based on achievement of financial goals and higher costs to operate and maintain the transmission and distribution systems. Compared to 2012, depreciation and amortization expense increased $0.7 million, reflecting the impact of additions to facilities to serve customers, largely offset by approximately $4.0 million of lower amortization on software retroactive to Jan. 1, 2013, due to the change in life for software agreed to in the base rate case settlement. Interest expense decreased $11.1 million in 2013, due to lower long-term debt interest rates and balances and a lower interest rate on customer deposits.

Base Rates

Prior to Nov. 1, 2013, Tampa Electric's results reflected base rates established in March 2009, when the FPSC awarded $104.0 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for combustion turbines and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

As a result of growth in rate base from required infrastructure added to serve customers, increasing pressure on O&M expense, and an economic recovery that was slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding in 2009, on April 5, 2013, Tampa Electric filed its petition with the FPSC for an increase in base rates and miscellaneous service charges in the amount of $134.8 million. In the petition, Tampa Electric requested an ROE level of 11.25% and a capital structure identical to that approved in 2009, with 54% equity.

After an extensive process by Tampa Electric, intervening parties and the FPSC staff, on Sept. 6, 2013, Tampa Electric and all of the intervening parties reached a Stipulation and Settlement Agreement resolving all of the issues in the proceeding. On Sept. 11, 2013, the FPSC approved the settlement that authorized base rate increases implemented at four different dates.

Under the settlement agreement, Tampa Electric was granted $57.5 million higher annual base rates effective Nov.1, 2013, an additional $7.5 million effective Nov. 1, 2014, an additional $5.0 million increase effective Nov.1, 2015, and $110 million of higher base rates effective Jan. 1, 2017, or when the Polk 2 – 5 conversion enters commercial service, whichever is later (see the Regulation section).

The table below provides a summary of Tampa Electric’s revenue and expenses and energy sales by customer type.

Summary of Operating Results

(millions)	2014	% Change	2013	% Change	2012
Revenues	$2,021.0	3.1	$1,950.5	(1.6)	$1,981.3
O&M expense	418.4	(2.0)	427.0	13.7	375.7
Depreciation and amortization	248.6	4.1	238.8	0.5	237.6
Taxes, other than income	154.7	3.3	149.7	(1.1)	151.3
Non-fuel operating expenses	821.7	0.8	815.5	6.7	764.6
Fuel expense	692.5	1.6	681.9	(1.8)	694.7
Purchased power expense	71.4	10.5	64.6	(38.7)	105.3
Total fuel & purchased power expense	763.9	2.3	746.5	(6.7)	800.0
Total operating expenses	1,585.6	1.5	1,562.0	(0.2)	1,564.6
Operating income	435.4	12.0	388.5	(6.8)	416.7
AFUDC equity	10.5	66.7	6.3	142.3	2.6
Net income	$224.5	17.6	$190.9	(1.1)	$193.1
Megawatt-Hour Sales (thousands)					
Residential	8,656	2.2	8,470	0.9	8,395
Commercial	6,142	0.9	6,090	(1.5)	6,185
Industrial	1,901	(6.2)	2,026	1.2	2,002
Other	1,827	(0.2)	1,832	0.2	1,827
Total retail	18,526	0.6	18,418	0.0	18,409
Sales for resale	259	16.7	222	(16.8)	267
Total energy sold	18,785	0.8	18,640	(0.2)	18,676
Retail customers—(thousands)					
Average	706.2	1.6	694.7	1.5	684.2
Retail net energy for load	19,315	0.7	19,178	(0.4)	19,255

Operating Revenues

In 2014, retail MWh sales, as measured on a billing cycle basis shown in the table above, grew 0.6% from 2013. Sales in 2014 reflected generally milder weather and lower per-customer usage, partially offset by 1.6% customer growth and improvements in the local economy. Pretax base revenue, which included $50.0 million of higher revenue as a result of the base rate settlement described above, was approximately $62.0 million higher than in 2013. In 2014, total retail net energy for load increased 0.7%, compared to 2013. In 2014, total degree days in Tampa Electric’s service area were 4% below normal, and 3% below 2013, reflecting generally milder weather throughout the year.

In 2013, retail MWh sales, as measured on a billing cycle basis shown in the table above, were essentially unchanged from 2012. Sales in 2013 reflected a mild winter and a rainy summer period and lower per-customer usage, partially offset by 1.5% customer growth and improvements in the local economy. Pretax base revenue, which included $10.0 million of higher revenue as a result of the base rate settlement described above, was approximately $13.0 million higher than in 2012. In 2013, total retail net energy for load decreased 0.4%, compared to 2012. In 2013, total degree days in Tampa Electric's service area were 1% below normal, and 1% below 2012, reflecting generally milder weather early in the year.

Tampa Electric is not a major participant in the wholesale market because it uses its lower cost coal-fired generation to serve its retail customers rather than the wholesale market. Over the past three years, gross revenues from wholesale sales, which includes fuel that is a pass-through cost, has averaged approximately 2% of Tampa Electric’s total revenue. Sales for resale increased 16.7% in 2014 due to weather related sales early in the year. Sales for resale decreased 16.8% in 2013, primarily due to changes in Tampa Electric’s wholesale rates and reduced demand due to the mild weather.

Customer and Energy Sales Growth Outlook

The Florida economy has continued to grow, as evidenced by job growth, and improvements in the new housing construction market, which was a major driver of growth in the Florida economy for many years (see the Risk Factors section). In general, economists are forecasting a continued improvement in the economy in 2015 and beyond. For the past several years, weather-normalized energy consumption per residential customer declined due to the combined effects of voluntary conservation efforts, economic conditions, improvements in lighting and appliance efficiency, smaller single-family houses and increased multi-family housing. The 2015 forecast used by Tampa Electric reflects a continuation of the average customer growth that was experienced in 2014, including continued lower per customer usage. Retail energy sales to residential, commercial and non-phosphate industrial customers are expected to grow by almost 1.0%. Total retail sales are expected to be about 0.3% higher, as sales to lower-margin interruptible Industrial-Phosphate customers are expected to decline due to increased self-generation.

Longer-term, assuming continued economic growth and business expansion, Tampa Electric expects average annual customer growth of about 1.5% and weather-normalized average retail energy sales growth about 0.5% lower than customer growth in the near term, and about 0.3% lower than customer growth over the longer-term. This energy sales growth projection reflects increased lighting and appliance efficiency, smaller new single family homes, increased percentage of multi-family homes, changes in usage patterns and changes in population trends. These growth projections assume continued local area economic growth, normal weather, and a continuation of the current energy market structure.

The economy in Tampa Electric’s service area continued to grow in 2014. The Tampa metropolitan area added more than 14,000 new jobs in 2014 after adding 35,000 new jobs in 2013. In both years, job growth was concentrated in business and other services. The total nonfarm employment in the Tampa metropolitan area increased 1.2% in 2014 following a 3.5% increase in 2013. The local Tampa area unemployment rate decreased to 5.6% at the end of 2014 compared with 6.3% at year-end 2013 and 7.6% at year-end 2012. The Tampa area year-end 2014 unemployment rate was below the state of Florida’s rate and the national rate, both 5.8%.

Operating Expenses

Total pretax operating expense was 1.5% higher in 2014, driven primarily by higher fuel and purchased-power expense and depreciation and amortization partially offset by lower O&M expense. Excluding all FPSC-approved cost-recovery clause-related expense, O&M expense decreased $1.0 million in 2014 reflecting lower employee-related costs, including pension expense, and the elimination of the storm damage reserve accrual, partially offset by higher costs to operate and maintain the system.

Total pretax operating expense was 0.2% lower in 2013, driven primarily by higher other operating expense more than offset by lower fuel and purchased-power expense. Excluding all FPSC-approved cost-recovery clause-related expense, O&M expense increased $19.4 million in 2013 reflecting $8.2 million of higher accruals for performance-based incentive compensation for all employees based on achievement of financial goals and higher costs to operate and maintain the transmission and distribution systems.

Compared to 2013, depreciation and amortization expense increased $6.0 million, reflecting additions to facilities to serve customers. In 2013 depreciation and amortization expense increased $0.7 million primarily as a result of approximately $4.0 million of lower amortization on software retroactive to Jan. 1, 2013, due to the change in depreciable life for software agreed to in the base rate case settlement, more than offset by depreciation of additions to facilities to serve customers. In 2015, depreciation expense is expected to increase at levels similar to those experienced in 2014.

Excluding all FPSC-approved cost-recovery clause-related expense, O&M expense in 2015 is expected to be lower than 2014, as higher costs to operate the system and reliably serve customers are offset by lower employee-related costs and the impact of synergies in Florida as a result of the NMGC integration.

Fuel Prices and Fuel Cost Recovery

In November 2014, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2015. The rates include the expected cost for natural gas and coal in 2015, and the net over-recovery of fuel, purchased power and capacity clause expense.

Total fuel cost increased in 2014, due to increased coal-fired generation and higher costs for natural gas and coal. Purchased-power expense increased in 2014 as the cost-per-MWh increased, due to higher natural gas prices, which is the primary fuel used by other generators in Florida. Delivered natural gas prices increased 9% in 2014 due to extreme winter weather and supply concerns early in the year. Gas prices had decreased 2% in 2013 as a result of mild winter weather and abundant supplies from on-shore domestic natural gas produced from shale formations, and storage inventories above historic averages. Delivered coal costs increased 3.6% in 2014. The average coal and natural gas costs were $3.48/MMBTU and $5.68/MMBTU, respectively, in 2014, compared with $3.36/MMBTU and $5.23/MMBTU in 2013.

Full-year Henry Hub natural gas futures as traded on the NYMEX and various forecasts for natural gas prices indicate that natural gas prices are expected to remain in the $3.00 - $3.50/MMBTU range in 2015 and 2016, which are approximately January 2015 levels. Compared to 2014, delivered coal prices are expected to decrease in 2015 due to lower transportation costs, and lower prices for fuel purchased in the spot market.

Energy Supply

Tampa Electric’s generation increased in line with energy sales growth in 2014, and purchased power increased due to lower gas-fired generation by Tampa Electric. Tampa Electric’s generation decreased in 2013 due to the mild weather and lower cost natural gas-fired generation available within Florida, which increased MWhs purchased but at a lower cost.

Prior to the conversion of the coal-fired Gannon Station to the natural gas-fired Bayside Power Station in 2003, nearly all of Tampa Electric’s generation was from coal. Upon completion of that conversion, the mix shifted with the increased use of natural gas. Coal is expected to continue to represent a significant portion of Tampa Electric’s fuel mix due to the baseload units at the Big Bend Power Station and the coal gasification unit, Polk Unit 1. Longer term, natural gas prices are expected to remain stable for several years, and we expect to maintain the generation mix at about current levels. Upon completion of the Polk 2-5 combine-cycle conversion project, Tampa Electric will have the ability to shift the generation mix to a higher percentage of energy from natural gas depending on cost and potential GHG regulation (see the Environmental section).

Polk Power Station Units 2 – 5 Combined Cycle Conversion

In 2012, Tampa Electric announced that, subject to FPSC approval, it planned to convert four CTs in peaking service at the Polk Power Station to combined cycle with an early 2017 in-service date. In 2012, as required under Florida regulations, Tampa Electric issued a request for proposal to determine its lowest cost option to provide generating capacity beginning in early 2017. The bid process showed that the lowest cost option to serve customers, over the long-term, was Tampa Electric’s planned conversion of CTs to combined-cycle operation.

In September 2012, Tampa Electric submitted a petition to the FPSC for a Determination of Need for the conversion of these peaking CTs to combined-cycle service. In December 2012, the FPSC conducted a hearing for the need, and the FPSC made a bench decision to approve the Polk Power Station Units 2 – 5 conversion. In November 2013, the governor of Florida and the Cabinet, acting as the Power Plant Siting Board, approved the construction of the conversion. In January 2014, the final emission permits were received and construction commenced. The capital expenditures for the conversion and the related transmission system improvements to support the additional generating capacity are included in the capital expenditure forecast located in the Capital Expenditures section. Capital spending in 2015 will support equipment procurement and construction. (See the Capital Expenditures and Regulation sections.)

PGS

Operating Results

In 2014, PGS reported net income of $35.8 million, compared with $34.7 million in 2013. Results reflect a 1.9% higher average number of customers and higher therm sales to residential and commercial customers due to more-normal winter weather and economic growth. Higher commercial sales volumes were also helped by an almost doubling of therms sold to CNG vehicle fleets. Sales to power generation customers decreased due to two power generators not operating. Off-system sales decreased due to new entrants in the Florida market. Depreciation and amortization expense increased $1.6 million due to normal additions to facilities to serve customers. Non-fuel operations and maintenance expense was in line with 2013.

In 2013, PGS reported net income of $34.7 million, compared with $34.1 million in 2012. Results reflected a 1.3% higher average number of customers and higher therm sales to all retail customer classes, due to more-normal first quarter weather and better economic conditions. Sales to power generation customers and off-system sales decreased due to the expiration of two contracts with power generators, new participants in the off-system sales market, and higher natural gas prices in 2013 compared to 2012. Non-fuel O&M expense increased $4.0 million compared to 2012 due to higher employee related costs, including $1.5 million of higher accruals for performance-based incentive compensation for all employees based on achievement of financial goals, and an insurance recovery that reduced O&M expense in 2012. Interest expense decreased $1.6 million, due to lower long-term debt interest rates and a lower interest rate on customer deposits.

In 2014, total throughput for PGS was more than 1.5 billion therms, down almost 8% from 2013 levels due to the lower volumes transported for power generation customers and lower off-system sales. Industrial and power generation customers represented approximately 59% of annual therm volume, commercial customers used approximately 30%, approximately 5% was sold off-system, and the remainder was consumed by residential customers.

In 2013, total throughput for PGS was almost 1.7 billion therms, down 10% from 2013 levels due to the lower volumes transported for power generation customers and lower off-system sales. Industrial and power generation customers represented approximately 61% of annual therm volume, commercial customers used approximately 26%, approximately 9% was sold off-system, and the remainder was consumed by residential customers.

Residential customers comprised 36% of total revenues in 2014, up from 32% of total revenues in each of the prior two years. New residential construction, which includes natural gas and conversions of existing residences to natural gas, increased in 2014 as the economy and the housing market in select markets in Florida rebounded.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam. PGS has also experienced increased interest in the usage of CNG as an alternative fuel for vehicles. Therms sold to CNG stations almost doubled in 2014 to 15.1 million therms, the equivalent usage of 60,000 Florida residential customers. Currently, there are 31 CNG fueling stations connected to the PGS system serving over 1,000 vehicles, and, at this time, an additional 13 stations are expected to be added in 2015, however the number of new stations may increase as the year progresses. Such initiatives add therm sales, at lower-margin transportation rates, to the gas system without requiring significant capital investment by PGS.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a PGA. Because this charge may be adjusted monthly based on a cap approved by the FPSC annually, PGS normally has a lower percentage of under- or over-recovered gas cost variances than Tampa Electric.

The table below provides a summary of PGS's revenue and expenses and therm sales by customer type.

Summary of Operating Results

(millions)	2014	% Change	2013	% Change	2012
Revenues	$399.6	1.6	$393.5	(1.4)	$398.9
Cost of gas sold	137.0	(3.9)	142.6	(9.5)	157.6
Operating expenses	190.5	5.2	181.1	6.5	170.0
Operating income	72.1	3.3	69.8	(2.1)	71.3
Net income	$35.8	3.2	$34.7	1.8	$34.1
Therms sold – by customer segment					
Residential	80.8	8.6	74.4	5.1	70.8
Commercial	460.5	5.1	438.1	4.0	421.4
Industrial	274.3	0.8	272.0	14.6	237.3
Off-system sales	84.0	(41.3)	143.1	(36.1)	224.0
Power generation	643.5	(13.5)	744.4	(18.5)	913.5
Total	1,543.1	(7.7)	1,672.0	(10.4)	1,867.0
Therms sold – by sales type					
System supply	194.2	(22.2)	249.5	(25.4)	334.3
Transportation	1,348.9	(5.2)	1,422.5	(7.2)	1,532.7
Total	1,543.1	(7.7)	1,672.0	(10.4)	1,867.0
Customer (thousands) – average	353.9	1.9	347.4	1.3	342.9

In Florida, natural gas service is unbundled for non-residential customers and residential customers that use more than 1,999 therms annually that elect this option, affording these customers the opportunity to purchase gas from any provider. The net result of unbundling is a shift from bundled transportation and commodity sales to transportation-only sales. Because the commodity portion of bundled sales is included in operating revenues at the cost of the gas on a pass-through basis, there is no net earnings impact to the company when a customer shifts to transportation-only sales. PGS markets its unbundled gas delivery services to customers through its "NaturalChoice" program. At year-end 2014, approximately 21,900 out of 36,000 of PGS's eligible non-residential customers had elected to take service under this program.

PGS Outlook

In 2015, PGS expects customer growth at rates in line with those experienced for the full year in 2014, reflecting its expectations that the housing markets in many areas of the state that it serves are now recovering. Assuming normal weather, therm sales to weather-sensitive customers, especially residential customers, are expected to increase in 2015 at rates in line with customer growth. Excluding all FPSC-approved cost-recovery clause-related expenses, O&M expense in 2015 is expected to be at levels similar to 2014, as higher costs to operate and maintain the system and to reliably serve customers are offset by lower employee-related costs and the impact of synergies in Florida as a result of the NMGC integration. Depreciation expense is expected to be higher due to normal additions to facilities to serve customers.

Since its acquisition by TECO Energy in 1997, PGS has expanded its gas distribution system into areas of Florida not previously served by natural gas, such as the lower southwest coast in the Fort Myers and Naples areas and the northeast coast in the Jacksonville area. In 2015, PGS expects capital spending to support moderate residential and commercial customer growth, system expansion to serve large commercial and industrial customers, continued interest in conversion of vehicle fleets to CNG and continued replacement of cast iron and bare steel pipe.

Due to the current rate of new residential development in Florida, which is considerably slower than in the 2005 to 2007 period, the PGS business model for system expansion has evolved to focus on extending the system to serve large commercial or industrial customers that are currently using petroleum or propane as fuel. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future make it attractive for these customers to convert from fuels that are currently three to four times more expensive on a cost-per-MMBTU basis.

Gas Supplies

PGS purchases gas from various suppliers, depending on the needs of its customers. The gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers.

Gas is delivered by the FGT pipeline through 66 interconnections (gate stations) serving PGS’s operating divisions. In addition, PGS’s Jacksonville Division receives gas delivered by the Southern Natural Gas Co. pipeline through two gate stations located northwest of Jacksonville. PGS also receives gas delivered by Gulfstream Natural Gas Pipeline through six gate stations, and by its affiliate, SeaCoast Gas Transmission LLC, through a single gate station in northeast Florida.

PGS procures natural gas supplies using baseload and swing-supply contracts with various suppliers along with spot market purchases. Pricing generally takes the form of either a variable price based on published indices, or a fixed price for the contract term.

NMGC

On Aug. 13, 2014, the NMPRC unanimously approved TECO Energy’s acquisition of NMGC. The transaction closed on Sept. 2, 2014. NMGC’s results for the final four months of the year, post-closing, reflected the normal seasonal earnings pattern with strong financial results for the fourth quarter, and were $0.01 accretive to TECO Energy’s earnings in 2014, which was sooner than originally forecast. NMGC results are expected to be accretive to TECO Energy’s full-year earnings in 2015, which is also sooner than originally forecast.

NMGC, headquartered in Albuquerque, is New Mexico’s largest regulated local natural gas distribution company. It provides natural gas service to almost 513,000 customers, primarily residential, in 23 of New Mexico’s 33 counties with a service area that encompasses nearly 60% of New Mexico’s population. With 69% of its customers in the Central Rio Grande Corridor, NMGC serves one of the fastest-growing regions in the state. NMGC’s major non-residential customers include military installations, power generators, computer chip makers, food processors, universities, refineries, wallboard manufacturers, government research facilities, and mining facilities.

The NMGC system is comprised of approximately 10,200 miles of distribution mains and 1,600 miles of high pressure transmission pipelines connecting the NMGC system in New Mexico. There is no cast iron pipe in the system and there are no environmental liabilities associated with manufactured gas plant sites.

NMGC operates in a state that has historically grown at rates above the national average. The acquisition provides us the opportunity to bring the natural gas marketing and development skills developed by PGS in Florida to New Mexico to grow NMGC.

NMGC Base Rates

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC's base rates by approximately $34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on Jan. 31, 2012, revising, among other things, base rates for all service provided on or after Feb. 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC's base rate revenue by approximately $21.5 million on a normalized annual basis. The monthly residential customer access fee increased from $9.59 to $11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017. In addition, under the order NMGC will provide $2.0 million of pretax credits on customer bills for the first 12-month period post-closing, effective Oct. 1, 2014, and $4.0 million of credits to customers in each subsequent 12-month period until new base rates are effective, see Note 16 to the Consolidated Financial Statements.

NMGC Operating Results

The NMGC discussion below includes only the September through December 2014 period of our ownership, unless otherwise noted.

In 2014, NMGC reported net income of $10.5 million for the four-month period of our ownership, which reflects the normally strong financial results for the early winter period. Customer growth for the four-month period was 0.5%. Total throughput for NMGC was almost 275.3 million therms, compared with 296.1 million therms for the four-month period in 2013. Heating degree days were 16% lower in the 2014 period than in the comparable period in 2013.

The table below provides a summary of NMGC's 2014 revenue and expenses since the closing of the acquisition in September 2014.

Summary of Operating Results

	For the four months ended Dec. 31		
(millions)	2014	% Change	2013
Revenues	$137.5	(3.1)	$141.9
Cost of gas sold	72.9	0.8	72.3
Operating expenses	43.0	(6.9)	46.2
Operating income	21.6	(7.7)	23.4
Net income	$10.5	(9.5)	$11.6
Therms sold – by customer segment			
Residential	108.2	(12.0)	122.9
Commercial	37.4	(11.8)	42.4
Industrial	1.6	0.0	1.6
Transportation - on system	111.6	(2.3)	114.2
Transportation - off system	16.5	10.0	15.0
Total	275.3	(7.0)	296.1
Therms sold – by sales type			
System supply	147.2	(11.8)	166.9
Transportation	128.1	(0.9)	129.2
Total	275.3	(7.0)	296.1
Customer (thousands) – average	512.6	0.5	510.3

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a PGAC. This charge may be adjusted monthly as allowed by the NMPRC (see the Regulation section).

NMGC is required to provide transportation-only services for all customer classes. As a result, NMGC receives its base rates for distribution gas delivery services regardless of whether a customer elects transportation-only service or continues as a customer of NMGC's gas commodity sales service. As of Dec. 31, 2014, NMGC had approximately 4,000 transportation-only customers and approximately 509,000 gas commodity sales service end-use customers. Transportation-only volume represented 48.5% of total system throughput for 2014, and 5.2% of total revenue.

NMGC Outlook

In 2015, NMGC expects customer growth rates slightly better than those experienced in 2014, reflecting its expectations that the New Mexico economy will grow. Assuming normal weather, therm sales are expected to essentially track customer growth. O&M expense is expected to decrease in 2015 primarily due to synergies as a result of the acquisition. As a condition of the August 2014 NMPRC order approving the acquisition, NMGC will provide $2.0 million of pretax credits on customer bills for the first 12-month period post-closing, effective Oct. 1, 2014, and $4.0 million of credits to customers in each subsequent 12-month period until new base rates are effective. Depreciation expense is expected to increase from continued capital investments in facilities to reliably serve customers.

NMGC Gas Supplies

NMGC purchases gas from various suppliers, depending on the needs of its customers. The gas is delivered to the NMGC transmission system through five interstate pipelines on which NMGC has reserved firm transportation capacity for delivery by NMGC to its customers.

OTHER (net)

In 2014, the cost from continuing operations for Other (net) was $64.4 million, compared with $36.9 million in 2013. The non-GAAP cost from continuing operations was $41.1 million in 2014, which excludes $16.6 million of NMGC acquisition- and integration-related costs and $6.7 million of net consolidated deferred income tax balance adjustments to reflect the pending sale of TECO Coal and the NMGC acquisition, compared with $30.6 million in 2013, which excluded $6.2 million of NMGC acquisition-related costs. The higher non-GAAP cost in 2014 reflects $1.4 million of NMGI interest expense, $1.0 million of interest expense previously allocated to TECO Coal, $3.5 million of labor and other unallocated costs, and $3.1 million of tax items, including offsets at parent to tax benefits at Tampa Electric.

The segment data in Note 14 presents Other and Eliminations as separate segments. The discussion above nets the two segments.

In 2013, the cost for Other (net) was $36.8 million, compared with $31.4 million in 2013. The non-GAAP cost from continuing operations for Other (net) in 2014 was $30.6 million, which excluded $6.2 million of costs associated with the acquisition of NMGC, compared with $31.4 million in 2013.

The 2015 non-GAAP cost for Other (net) is expected to be higher than 2014 levels. While the benefit of refinancing the $191 million of TECO Finance 6.75% notes maturing in the spring of 2015 in the current low interest-rate environment is expected to offset the impact of no longer allocating interest expense to TECO Coal, interest expense in 2015 will reflect a full year of interest on debt at NMGI.

DISCONTINUED OPERATIONS

As a result of our Board of Directors authorizing us to enter into negotiations for the sale of TECO Coal, effective in the third quarter it was classified as asset held for sale and its results for all periods reported as discontinued operations.

In 2014, discontinued operations resulted in a loss of $76.0 million comprised of the full-year operating results discussed below, $76.4 million of after-tax impairment charges and tax valuation allowances, and net benefits of $6.0 million recorded in the Other segment, relating to taxes and the 2012 sale of TECO Guatemala.

TECO Coal’s full-year loss from operations in 2014 was $5.6 million on sales of 5.5 million tons, compared with net income of $9.0 million on 5.8 million tons sold in the 2013 period. The 2014 results reflect selling prices and costs associated with reductions in personnel and steps taken in advance of closing the sale of the company. In 2013, TECO Coal recorded net income of $9.0 million on sales of 5.8 million tons, compared with $50.2 million on sales of 6.3 million tons in 2012.

TECO Guatemala Holdings (TGH), a wholly owned subsidiary of TECO Energy until 2012, had subsidiaries with interests in independent power generating projects in Guatemala. In 2012, TGH sold all of its equity interests in the Alborada and San José power stations, and related solid fuel handling and port facilities in Guatemala, for a total purchase price of $227.5 million in cash.

Losses of $33.3 million in 2012 were reported as discontinued operations, including the results from operations of $18.2 million for the generating plants in Guatemala through the closing of the sales, a $28.6 million loss on assets sold including transaction costs, and a $22.9 million charge associated with foreign tax credit write offs.

While TECO Energy and its subsidiaries no longer have assets or operations in Guatemala, TGH has retained its rights under an arbitration claim against the Republic of Guatemala under the Dominican Republic Central America – United States Free Trade Agreement (DR – CAFTA). See Note 12 to the TECO Energy Consolidated Financial Statements.

OTHER ITEMS IMPACTING NET INCOME

Other Income (Expense)

Other income (expense) of $11.0 million in 2014 and of $8.1 million in 2013 included miscellaneous services at the utilities such as lightning surge protection equipment.

AFUDC-equity at Tampa Electric, which is included in Other income (expense), was $10.5 million, $6.3 million and $2.6 million in 2014, 2013 and 2012, respectively. AFUDC is expected to increase in 2015 primarily due to the spending related to the Polk Units 2 – 5 conversion project (see the Liquidity, Capital Resources section).

Interest Expense

In 2014, interest expense, excluding AFUDC-debt, was $176.4 million compared to $165.0 million in 2013 and $177.9 million in 2012. In 2014, interest expense increased due to the addition of NMGC and NMGI debt upon the acquisition in September 2014, and additional borrowings at TEC to support its capital spending program (see Financing Activity section).

Interest expense is expected to increase in 2015, reflecting a full year of NMGC and NMGI debt, and increased borrowing at Tampa Electric to support the construction of the Polk Power Station Units 2 – 5 conversion, partially offset by the expected refinancing of the $191 million of 6.75% TECO Finance notes at maturity in the spring of 2015 at lower interest rates.

Income Taxes

The provision for income taxes from continuing operations increased in 2014, primarily due to higher pre-tax income and net consolidated state deferred income tax balance adjustments of $6.7 million. The provision for taxes was lower in 2013, primarily due to lower pre-tax income. Income tax expense as a percentage of income from continuing operations before taxes was 40.2% in 2014, 37.4% in 2013 and 38.0% in 2012. We expect our 2015 annual effective tax rate to be approximately 38.0%.

The cash payments for federal income taxes, as required by the federal AMT rules, state income taxes, foreign income taxes and payments (refunds) related to prior years' audits totaled $2.9 million, $1.8 million and $7.2 million in 2014, 2013 and 2012, respectively.

Due to the NOL carryforward position resulting from the disposition of the generating assets formerly held by our merchant power subsidiary, cash tax payments for income taxes are limited to approximately 10% of the AMT rate. We expect future cash tax payments to be limited to a similar level and various state taxes. As a result of bonus depreciation enacted under economic stimulus legislation since 2008, the Final Tangible Property Regulations on repair expenditures released in 2013, and the incremental bonus depreciation allowed under the Tax Increase Prevention Act of 2014 enacted on Dec. 19, 2014, we currently project to utilize these NOL carryforwards primarily in the 2015 through 2019 period. Beginning in 2019, we also expect to start using more than $214 million of AMT carry-forwards to limit future cash tax payments for federal income taxes to the level of AMT. We currently project minimal cash tax payments through 2018.

The utilization of the NOL and AMT carryforwards are dependent on the generation of sufficient taxable income in future periods.

For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective tax rate, see Note 4 to the TECO Energy Consolidated Financial Statements.

LIQUIDITY, CAPITAL RESOURCES

The table below sets forth the Dec. 31, 2014 consolidated liquidity and cash balances, the cash balances at the operating companies and TECO Energy parent, and amounts available under the TECO Energy/Finance, TEC and NMGC credit facilities.

Balances as of Dec. 31, 2014

(millions)	Consolidated	TEC	NMGC	TECO Finance Parent/other
Credit facilities	$ 900.0	$475.0	$125.0	$ 300.0
Drawn amounts/LCs	141.3	58.6	32.7	50.0
Available credit facilities	758.7	416.4	92.3	250.0
Cash and short-term investments	25.4	10.4	5.0	10.0
Total liquidity	$ 784.1	$426.8	$97.3	$ 260.0

In September 2014, we acquired all of the capital stock of NMGI, the parent company of NMGC. The aggregate purchase price was $950 million which included the assumption of $200 million of senior notes at NMGC. Sources of funding for the acquisition included net proceeds of $292 million from issuing TECO Energy common stock, issuance of $270 million of senior unsecured notes by NMGI and NMGC (of which $219 million was used to retire outstanding debt of NMGI and NMGC at closing), cash balances of

TECO parent and short term borrowings of TECO Finance. The cash balance of TECO Energy parent was $10 million at Dec. 31, 2014 down from $172 million at the beginning of the year, and TECO Finance had short-term borrowings outstanding of $50 million at Dec. 31, 2014, compared to no short-term borrowings outstanding at Dec. 31, 2013.

Our cash from operations in 2014 was $665 million. TEC issued $300 million of 30-year notes in support of its capital spending program, and retired $83 million of debt at maturity. Total capital expenditures were $714 million, and we paid dividends of $199 million in 2014.

Cash from Operations

In 2014, consolidated cash flow from operations was $665 million, compared to $659 million in 2013. Cash from operations in 2014 reflects the benefit of operating cash from four months of NMGC post-acquisition operations and strong results from TEC, largely offset by the impact of weak coal markets at TECO Coal and transaction and integration costs associated with the acquisition of NMGC. Cash from operations in 2014 and 2013 reflect annual pension contributions of $40 million.

We made minimal cash payments for state and federal income taxes in 2014 (see the Income Taxes section). Bonus depreciation, enacted under economic stimulus legislation annually since 2008, has significantly reduced federal taxable income at Tampa Electric and PGS. Additionally, the 2014 Tax Increase Prevention Act enacted on Dec. 19, 2014 is expected to provide our regulated businesses incremental bonus depreciation for 2014 and 2015. We file a consolidated tax return, and under our tax sharing agreements, each subsidiary's tax payment is determined on a standalone basis. Significant NOL carryforwards are available at TECO Energy parent that can be used to offset taxable income in the consolidated return such that cash payments for federal income taxes are limited to approximately 10% of the AMT rate. During the period of bonus depreciation, taxable income has been reduced significantly by the bonus depreciation deductions, and as a result we have utilized our NOL carryforwards less than expected in recent years. TECO Energy parent cash flows have therefore been less than expected through this period, and our projection for the full utilization of the NOL carryforwards has been extended to 2019. Tampa Electric and PGS have realized higher cash flows in recent years as a result of reduced cash taxes from bonus depreciation, which has supported their capital spending programs. While 2015 is expected to be the final year available for bonus depreciation under current legislation, we expect that Tampa Electric, PGS and NMGC will continue to realize significant cash tax savings as a result of the Final Tangible Property Regulations on repair expenditures released in 2013, and that TECO Energy parent will realize the cash benefit of the NOL carryforwards primarily in the 2016 through 2019 period.

We expect cash from operations to increase in 2015, driven by higher operating results primarily at Tampa Electric, and the addition of NMGC. In November 2014, the FPSC approved fuel-adjustment and other recovery clause rates that provide for refunds to customers of estimated 2014 net over-recoveries of fuel and purchased power over 12 months beginning Jan. 1, 2014 (see the Regulation section).

Cash from Investing Activities

Our investing activities in 2014 resulted in a net use of cash of $1,463 million, which reflects primarily $751 million related to the acquisition of NMGC and capital expenditures totaling $714 million.

We expect capital spending in 2015 to be approximately $735 million (see the Capital Expenditures section).

Cash from Financing Activities

Our financing activities in 2014 resulted in net cash generation of $638 million. Tampa Electric issued $300 million of long-term debt to repay $83 million of maturing debt and for general corporate purposes, including the net repayment of $26 million under its credit facilities (see the Financing Activity section). We issued $270 million of long-term debt at NMGI and NMGC and borrowed $31 million under the NMGC credit facility primarily to repay existing debt at closing of the NMGI acquisition, and we issued $302 million of common equity, including the exercise of stock options. (see the Financing Activity section). TECO Finance supplemented cash needs in 2014 with $50 million of borrowings under its credit facility. We paid $199 million in common stock dividends.

Cash and Liquidity Outlook

In general, we target consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of at least $500 million. At Dec. 31, 2014, our consolidated liquidity was $784 million, consisting of $427 million at TEC, $97 million at NMGC, and $260 million at TECO Energy parent/other.

We expect our sources of cash in 2015 to include cash from operations at levels above 2014, due in large part to higher net income from the regulated Florida operating companies and the addition of NMGC, proceeds from the expected sale of TECO Coal upon closing, long-term debt issuance of $250-$300 million and repayment of $83 million at TEC, and long-term debt issuance of $150-$250 million and repayment of $191 million of TECO Finance notes with a spring 2015 maturity. We plan to use cash in 2015 to fund capital spending estimated at $735 million, and to pay dividends to shareholders.

We expect to continue to make equity contributions to TEC in 2015 in order to support the utilities' capital structure and financial integrity. TEC expects to fund its capital needs with a combination of internally generated cash and equity contributions from us, and we anticipate that these contributions will total $175 million in 2015.

Our goal is to reduce leverage at TECO Finance over time as we are able to utilize our NOL carryforwards and as the equity needs of Tampa Electric normalize after the peak capital spending expected over the next several years during the Polk combined cycle conversion project (see the Capital Expenditures section). Our long-term debt maturities for TECO Finance total $191 million in 2015, $250 million in 2016, $300 million in 2017 and $300 million in 2020.

Our regulated businesses expect to utilize cash from operations and equity contributions from TECO Energy to support their capital spending programs, supplemented with incremental long-term debt and utilization of their credit facilities to maintain strong utility capital structures. Our credit facilities contain certain financial covenants (see Covenants in Financing Agreements section). Although we expect the normal utilization of our credit facilities to be low, we estimate that we could fully utilize the total available capacity under our facilities in 2015 and remain within the covenant restrictions.

Our expected cash flow could be affected by variables discussed in the individual operating company sections, such as customer growth, weather and usage changes at our regulated businesses, and coal margins. In addition, actual fuel and other regulatory clause net recoveries will typically vary from those forecasted; however, the differences are generally recovered within the next calendar year. It is possible, however, that unforeseen cash requirements and/or shortfalls, or higher capital spending requirements, could cause us to fall short of our liquidity target (see the Risk Factors section).

As a result of our significant reduction of parent debt, and reduced business risk, we have improved our debt credit ratings in recent years (see Credit Ratings section). In the unlikely event TECO Energy's, TEC's or NMGC's ratings were downgraded to below investment grade, counterparties to our derivative instruments could request immediate payment or full collateralization of net liability positions. If the credit risk-related contingent features underlying these derivative instruments were triggered as of Dec. 31, 2014, we could have been required to post additional collateral or settle existing positions with counterparties totaling $42.7 million. In addition, credit provisions in long-term gas transportation agreements at our electric and gas utilities would give the transportation providers the right to demand collateral, which we estimate to be approximately $63.5 million. None of our credit facilities or financing agreements have ratings downgrade covenants that would require immediate repayment or collateralization.

SHORT-TERM BORROWING

Credit Facilities

At Dec. 31, 2014 and 2013, the following credit facilities and related borrowings existed:

	Dec. 31, 2014			Dec. 31, 2013		
(millions)	Credit Facilities	Borrowings Outstanding[(1)]	Letters of Credit Outstanding	Credit Facilities	Borrowings Outstanding[(1)]	Letters of Credit Outstanding
Tampa Electric Company:						
5-year facility[(2)]	$325.0	$ 12.0	$ 0.6	$325.0	$ 6.0	$ 0.7

1-year accounts receivable facility	150.0	46.0	0.0	150.0	78.0	0.0
TECO Energy/TECO Finance:						
5-year facility(2)(3)	300.0	50.0	0.0	200.0	0.0	0.0
New Mexico Gas Company:						
5-year facility(2)	125.0	31.0	1.7	0.0	0.0	0.0
Total	$900.0	$ 139.0	$ 2.3	$675.0	$ 84.0	$ 0.7

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

These credit facilities require commitment fees ranging from 12.5 to 30.0 basis points. The weighted average interest rate on outstanding amounts payable under the credit facilities at Dec. 31, 2014 and 2013 was 1.16% and 0.56%, respectively.

TECO Energy/TECO Finance, TEC and NMGC have credit facilities with total borrowing capacities of $300 million, $475 million and $125 million, respectively. For a complete description of the credit facilities see Note 6 to the TECO Energy Consolidated Financial Statements

The table below sets forth TECO Finance, TEC and NMGC maximum, minimum, and average credit facility utilization in 2014.

2014 Credit Facility Utilization

(millions)	Maximum drawn amount	Minimum drawn amount	Average drawn amount	Average interest rate
TECO Finance	$ 175.0	$ 0.0	$ 22.0	1.28 %
TEC	$ 143.0	$ 0.0	$ 33.1	0.62 %
NMGC	$ 85.0	$ 0.0	$ 15.2	1.29 %

Significant Financial Covenants

In order to utilize their respective bank credit facilities, TECO Energy, TECO Finance, TEC, NMGC and NMGI must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, TECO Finance, and the other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2014, we were in compliance with all applicable financial covenants. The table that follows lists the significant financial covenants and the performance relative to them at Dec. 31, 2014. Reference is made to the specific agreements and instruments for more details.

(millions, unless otherwise indicated)

Instrument	Financial Covenant (1)	Requirement/Restriction	Calculation at Dec. 31, 2014
TEC			
Credit facility (2)	Debt/capital	Cannot exceed 65%	46.9%
Accounts receivable credit facility (2)	Debt/capital	Cannot exceed 65%	46.9%
6.25% senior notes	Debt/capital Limit on liens (3)	Cannot exceed 60% Cannot exceed $700	46.9% $0 liens outstanding
NMGC			
Credit facility (2)	Debt/capital	Cannot exceed 65%	31.3%
3.54% and 4.87% senior unsecured notes	Debt/capital	Cannot exceed 65%	31.3%
NMGI			
2.71% and 3.64% senior unsecured notes	Debt/capital	Cannot exceed 65%	48.1%
TECO Energy/TECO Finance			
Credit facility (2)	Debt/capital	Cannot exceed 65%	59.1%
TECO Finance 6.75% notes	Restrictions on secured debt (4)	(5)	(5)

(1) As defined in each applicable instrument.

(2) See Note 6 to the TECO Energy, Inc. Consolidated Condensed Financial Statements for a description of the credit facilities.

(3)

If the limitation on liens is exceeded, the company is required to provide ratable security to the holders of these notes.

(4) These restrictions would not apply to first mortgage bonds of TEC if any were outstanding.

(5) The indenture for these notes contain restrictions which limit secured debt of TECO Energy if secured by principal property, capital stock or indebtedness of directly held subsidiaries (with exceptions as defined in the indentures) without equally and ratably securing these notes.

Credit Ratings of Senior Unsecured Debt

	Standard & Poor's (S&P)	Moody's	Fitch
Tampa Electric Company	BBB+	A2	A-
New Mexico Gas Company	BBB+	-	-
TECO Energy/TECO Finance	BBB	Baa1	BBB

On Oct. 27, 2014, S&P placed the issuer credit rating of TECO Energy and the senior unsecured debt rating of its subsidiaries, TECO Finance, TEC and NMGC on credit watch with positive implications, following the announcement of the agreement to sell TECO Coal.

S&P, Moody's and Fitch describe credit ratings in the BBB or Baa category as representing adequate capacity for payment of financial obligations. The lowest investment grade credit ratings for S&P is BBB-, for Moody's is Baa3 and for Fitch is BBB-; thus, all three credit rating agencies assign TECO Energy, TECO Finance, TEC and NMGC's senior unsecured debt investment-grade credit ratings.

A credit rating agency rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Our access to capital markets and cost of financing, including the applicability of restrictive financial covenants, are influenced by the ratings of our securities. In addition, certain of TEC's derivative instruments contain provisions that require TEC's debt to maintain investment grade credit ratings (see Note 12 to the TECO Energy Consolidated Financial Statements). The credit ratings listed above are included in this report in order to provide information that may be relevant to these matters and because downgrades, if any, in credit ratings may affect our ability to borrow and may increase financing costs, which may decrease earnings (see the Risk Factors section). These credit ratings are not necessarily applicable to any particular security that we may offer and therefore should not be relied upon for making a decision to buy, sell or hold any of our securities.

Off-Balance Sheet Arrangements

TECO Energy and our subsidiaries have no off-balance sheet arrangements.

Summary of Contractual Obligations

The following table lists the obligations of TECO Energy and its subsidiaries for cash payments to repay debt, lease payments and unconditional commitments related to capital expenditures. This table does not include contingent obligations, which are discussed in a subsequent table.

Contractual Cash Obligations at Dec. 31, 2014

	Payments Due by Period					
(millions)	Total	2015	2016	2017	2018-2019	After 2019
Long-term debt (1)	$3,610.5	$274.5	$333.4	$300.0	$ 354.2	$ 2,348.4
Operating leases/rentals/capacity payments (2)	118.8	38.9	22.6	16.9	22.0	18.4
Net purchase obligations/commitments (2) (3)	321.6	204.5	86.8	19.8	10.5	0.0
Interest payment obligations	1,980.6	175.4	158.8	151.2	235.4	1,259.8
Pension plan (4)	0.0	0.0	0.0	0.0	0.0	0.0
Total contractual obligations	$6,031.5	$693.3	$601.6	$487.9	$ 622.1	$ 3,626.6

(1) Includes debt at TECO Finance, Tampa Electric, PGS, NMGI and NMGC (see Note 7 to the TECO Energy Consolidated Financial Statements for a list of long-term debt and the respective due dates).

(2) The table above excludes payment obligations under contractual agreements of Tampa Electric, PGS and NMGC for fuel, fuel transportation and power purchases which are recovered from customers under regulatory clauses approved by the FPSC and NMPRC (see the Regulation section).

(3) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2014, these commitments include Tampa Electric's outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines.

(4) Under calculation requirements of the Pension Protection Act, as of the Jan. 1, 2015 measurement date, our pension plan was essentially fully funded. Under MAP 21, we are not required to make additional cash contributions over the next five years; however we may make additional cash contributions from time to time. Future contributions are subject to annual valuation reviews, which may vary significantly due to changes in interest rates, discount rate assumptions, plan asset performance, which is affected by stock market performance, and other factors (see Liquidity, Capital Resources section and Note 5 to the TECO Energy Consolidated Financial

Statements).

53

The following table summarizes the letters of credit and guarantees outstanding that are not included in the Contractual Cash Obligations table above and not otherwise included in our Consolidated Financial Statements.

Contingent Obligations at Dec. 31, 2014

	Commitment Expiration	
(millions)		Total (1)
Letters of credit	Tampa Electric	$0.6
	NMGC	1.7
Guarantees	Fuel sales and transportation	92.9
Total contingent obligations		$95.2

(1) These guarantees and letters of credit renew annually and are assumed to continue to renew beyond 2019. None are expected to expire in the 2015 – 2019 period.

CAPITAL INVESTMENTS

		Forecast			
(millions)	Actual 2014	2015	2016	2017-2019	2015 - 2019 Total
Tampa Electric (1)					
Transmission	$35	$30	$25	$ 70	$ 125
Distribution	115	120	155	465	740
Generation	130	120	135	355	610
New generation and transmission	205	215	120	145	480
Other	40	60	55	80	195
Other environmental	65	25	5	45	75
Tampa Electric total	590	570	495	1,160	2,225
Net cash effect of accruals, retentions and AFUDC	0	0	0	0	0
Tampa Electric net	590	570	495	1,160	2,225
PGS	90	105	100	300	505
NMGC (2)	20	60	95	145	300
Other companies	0	0	0	0	0
Total (3)	$700	$735	$690	$ 1,605	$ 3,030

(1) Individual line items exclude AFUDC-debt and equity; however total AFUDC is a reconciling item in 2014.
(2) Represents capital expenditures in the September through December 2014 ownership period only.
(3) Excludes capital expenditures at TECO Coal of approximately $15 million in 2014.

TECO Energy's 2014 capital expenditures of $715 million included $590 million at Tampa Electric, excluding AFUDC debt and equity. Tampa Electric's capital expenditures in 2014 included $205 million for the Polk 2 -5 conversion to combined cycle and related transmission system improvements, $16 million for a reclaimed water pipeline to serve the Polk Power Station, approximately $45 million to improve the Big Bend Station solid fuel handling and flue gas desulphurization systems reliability, and approximately $40 million for equipment and facilities to meet customer growth, generating equipment maintenance, and environmental compliance. Capital expenditures for PGS were approximately $90 million, including approximately $30 million for maintenance of the existing system, $45 million to expand the system and support customer growth, and $14 million for replacement of cast iron and bare steel pipe. NMGC capital expenditures of $20 million for the four-month 2014 ownership period included amounts to support customer growth, system reliability, and facilities and equipment to safely and reliably operate the system.

TECO Energy estimates capital spending to be $735 million for 2015 and approximately $2.3 billion during the 2016 to 2019 period. As described below, this forecast includes $335 million for Tampa Electric's Polk 2 – 5 conversion to combined cycle, including transmission system improvements to support the increased plant output.

For 2015, Tampa Electric expects to spend $570 million. For the transmission and distribution systems, Tampa Electric expects to spend $150 million in 2015, including approximately $120 million for normal transmission and distribution system expansion and reliability, and approximately $30 million for transmission and distribution system storm hardening. Capital expenditures for the existing generating facilities of $120 million include approximately $20 million for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, approximately $90 million for generating system reliability in 2015 and advance purchases for 2016 unit outages, and $10 million for the conversion of distillate oil igniters to natural gas. In addition, Tampa Electric expects to spend $25 million for environmental compliance programs and improvements to environmental control equipment in 2015. The capital expenditure forecast includes $5 million for a 2 MW solar array that Tampa Electric will build, own and operate at Tampa International Airport.

Tampa Electric also expects to spend approximately $25 million in the first year of its program to replace its Customer Information System with a state-of-the-art Customer Relationship Management and Billing System (CRMB). This system is the first step in modernizing the distribution system to enable the implementation of smart-grid technologies in the post-2016 forecast period. Tampa Electric expects to spend an additional $20 million in 2016 to complete the CRMB project.

In the 2016 to 2019 period, Tampa Electric expects to spend approximately $360 million annually to support normal system growth and reliability, environmental compliance and improvements to computer systems to serve customers. This level of ongoing capital expenditures reflects the costs for materials and contractors, long-term regulatory requirements for storm hardening, and an active program of transmission and distribution system upgrades which will occur over the forecast period. These programs and requirements include: approximately $20 million annually for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, average annual expenditures of more than $90 million to support generating unit availability and reliability; average annual expenditures of almost $15 million for environmental compliance; average annual expenditures of more than $35 million for general infrastructure and facilities, including the CRMB project and other software upgrades; average annual expenditures of approximately $25 million for transmission and distribution system storm hardening; and approximately $145 million annually for transmission and distribution system capacity improvements to meet expected stronger customer growth and reliability.

The capital spending forecast for Generation, shown in the table above, includes approximately $120 million for modifications to the Polk Unit 1 gassifier to produce a high value by-product. Spending on this project and any other revenue enhancing projects must be justified by an internal economic analysis that demonstrates a net benefit.

Tampa Electric's capital spending forecast includes amounts related to the conversion of the Polk Units 2 – 5 from peaking service to combined cycle with a January 2017 in-service date. Construction commenced in January 2014. The capital expenditures for the conversion and the related transmission system improvements to support the additional generating capacity are included in the "New generation and transmission" line in the Capital Investments table above. The peak capital spending is forecast at $335 million for both the transmission system and plant conversions in the 2015 and 2016 periods.

New generation and transmission for the 2017 – 2019 period includes approximately $140 million for a simple cycle peaking unit scheduled to be in-service in early 2020. Tampa Electric recognizes that the proposed Clean Power Plan (see the Environmental section) favors generating resources with lower or no carbon emissions. Tampa Electric may meet the need for additional generating capacity in 2020 with a conventional peaking unit or some combination of conventional generation and renewable resources such as solar.

Capital expenditures for PGS are expected to be about $100 million in 2015 and $400 million during the 2016 to 2019 period. Included in these amounts is an average of approximately $65 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety, including approximately $10 million annually for the replacement of cast iron and bare steel pipe, which is recovered through a rider clause approved by the FPSC in 2012 (see the Regulation section).

At PGS, higher capital expenditures are focused on extending the system to serve large commercial or industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current natural gas prices and the projections that natural gas prices are going to remain low into the future makes it attractive for these customers to convert from fuels that are more expensive on a cost per MMBTU basis. In the current low oil price environment, the economics of converting to natural gas remain attractive for the long term, and natural gas has lower CO_2 emissions than petroleum based fuels that are attractive to users.

The NMGC capital expenditure forecast shown above includes approximately $20 million annually for ongoing renewal, replacement and system safety. Capital expenditures in 2016 include approximately $40 million for a transmission pipeline “looping” project to enhance system reliability and capacity for anticipated growth. The forecast for 2015 and 2016 includes approximately $15 million annually for software and systems upgrades, which are components of the integration plans with TECO Energy. The NMGC capital spending forecast is expected to increase in future years as marketing, economic development and system expansion plans are further developed in the integration process. The capital expenditure forecast does not include any amounts that might be required to improve system reliability to prevent service interruptions, such as occurred in New Mexico in 2011, as a solution is subject to approval by the NMPRC. See Note 12 to the TECO Energy Consolidated Financial Statements. As a condition of the NMPRC approval of the acquisition, TECO Energy and NMGC agreed to review a previously proposed LNG storage facility to determine if it is the optimal solution and to present a proposed solution to the NMPRC in 2015.

The forecast of capital expenditures shown above is based on our current estimates and assumptions for normal maintenance capital at the operating companies; capital expenditures to support normal system reliability and growth at Tampa Electric, PGS and NMGC; the replacement of cast iron and bare steel pipe at PGS; the programs for transmission and distribution system storm hardening and transmission system reliability requirements; generating capacity expansion at Tampa Electric and incremental investments above normal maintenance capital to expand the PGS and NMGC systems. Actual capital expenditures could vary materially from these estimates due to changes in costs for materials or labor or changes in plans (see the Risk Factors section).

Financing Activity

Our year-end 2014 consolidated capital structure was 59% debt and 41% common equity. The debt-to-total-capital ratio has improved significantly since 2006, primarily due to the repayment of more than $1.0 billion of parent and parent-guaranteed debt, consisting of $779 million in 2007, a net $189 million in 2010, $64 million in 2011, and $9 million in 2012. The consolidated debt-to-total capital ratio increased in 2014 due to debt issued to finance the NMGC acquisition and long-term debt issued at TEC. At Dec. 31, 2014, TEC's year-end capital structure was 47% debt and 53% common equity.

In 2014 and 2013, we raised $302.3 million and $6.7 million, respectively, of equity through an underwritten public offering of our common stock in July 2014 and through the exercise of stock options in both years. The 2014 equity offering was in connection with our acquisition of NMGC.

NMGC acquisition-related financing included the issuance of $200 million of debt at NMGI and $70 million of debt at NMGC, proceeds from which were used to repay existing debt of $219 million and to fund the transaction, costs and expenses.

For a complete description of the NMGC acquisition related debt financing and the issuance of $300 million of debt at TEC, see Note 7 to the TECO Energy Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of consolidated financial statements requires management to make various estimates and assumptions that affect revenues, expenses, assets, liabilities, and the disclosure of contingencies. The policies and estimates identified below are, in the view of management, the more significant accounting policies and estimates used in the preparation of our consolidated financial statements. These estimates and assumptions are based on historical experience and on various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and judgments under different assumptions or conditions. See Note 1 to the TECO Energy Consolidated Financial Statements for a description of our significant accounting policies and the estimates and assumptions used in the preparation of the consolidated financial statements.

Deferred Income Taxes

We use the asset and liability method in the measurement of deferred income taxes. Under the asset and liability method, we estimate our current tax exposure and assess the temporary differences resulting from differing treatment of items, such as depreciation, for financial statement and tax purposes. These differences are reported as deferred taxes measured at current rates in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not that some or the entire deferred tax asset will not be realized. If we determine that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

At Dec. 31, 2014, we had a net deferred income tax liability of $446.4 million, attributable primarily to property-related items, AMT credit carryforwards and net operating loss carryforwards. Based primarily on historical income levels and the company's expectations for steady future earnings growth, management has determined that the deferred tax assets associated with operating losses and AMT credit carryforwards recorded at Dec. 31, 2014, other than certain state related tax benefits, will be realized in future periods. See further discussion of valuation allowance in Note 4 to the TECO Energy Consolidated Financial Statements.

We believe that the accounting estimate related to deferred income taxes, and any related valuation allowance, is a critical estimate for the following reasons: 1) realization of the deferred tax asset is dependent upon the generation of sufficient taxable income, both operating and capital, in future periods; 2) a change in the estimated valuation reserves could have a material impact on reported assets and results of operations; and 3) administrative actions of the IRS or the U.S. Treasury or changes in law or regulation could change our deferred tax levels, including the potential for elimination or reduction of our ability to utilize the deferred tax assets.

The FASB has guidance that prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. See further discussion of uncertainty in income taxes and other tax items in Note 4 to the TECO Energy Consolidated Financial Statements.

Employee Postretirement Benefits

We sponsor a defined benefit pension plan (pension plan) that covers substantially all employees. In addition, we have an unfunded non-qualified, non-contributory supplemental executive retirement benefit plan available to certain members of senior management. We believe that the accounting related to employee postretirement benefits is a critical accounting estimate for the following reasons: 1) a change in the estimated benefit obligation could have a material impact on reported assets, AOCI and results of operations; and 2) changes in assumptions could change the annual pension funding requirements, which could have a significant impact on the company’s annual cash requirements.

Several statistical and other factors, which attempt to anticipate future events, are used in calculating the expense and liability related to these plans. Key factors include assumptions about the expected rates of return on plan assets, discount rates and mortality rates. We determine these factors within certain guidelines and with the help of external consultants. We consider market conditions, including changes in investment returns and interest rates, in making these assumptions.

Pension plan assets (plan assets) are invested in a mix of equity and fixed-income securities. The expected return on assets assumption was based on expectations of long-term inflation, real growth in the economy, fixed income spreads and equity premiums consistent with the company’s portfolio, with provision for active management and expenses paid from the trust that holds the plan assets. Due to the continued low interest rate environment, we reduced our expected return on assets from 7.50% used in 2013 to 7.25% at our Jan. 1, 2014 valuation and to 7.00% at our Aug. 31, 2014 and Oct. 31, 2014 remeasurements. We will continue to monitor the above-listed factors to determine whether it is appropriate to change the expected return on assets in the future. Actual earned returns in 2014 were 7.9%.

The discount rate assumption used to determine the 2014 benefit expense and Dec. 31, 2014 benefit obligation was based on a cash flow matching technique developed by the company’s outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by Moody’s) corporate bonds available from the Bloomberg Finance LP database at the measurement dates to meet the plan’s year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

In October 2014, the Society of Actuaries (SOA) released its final report of the RP-2014 mortality tables. The SOA tables incorporate the results of the SOA’s study of actual mortality of pension plans from 2004 – 2009. However, concerns have been raised over excluded data, as the bulk of the study came from five very large plans that may not be indicative of the general population, and the potential that the study was overly optimistic in projecting results from 2006 data (the central year of data in the study) to 2014. As a result of these concerns, the SOA conceded that it may be appropriate to use other projection scales.

We reviewed our actuary’s independent study to assess whether the RP -2014 base table was appropriate for its clients in various industries. The study found that the changes observed by the SOA for the base mortality rate were appropriate on a nationwide basis, including the utility sector (although other industries exhibited more significant variations). However, based on data published by the Social Security Administration (SSA), the study concluded that the SOA’s projection of the 2006 data to 2014 was potentially overly optimistic and that other mortality projection scales could also be considered reasonable. The projection scale analysis focused on ages between 65 and 84, since that population is key in determining pension plan costs, and found that the ultimate annual improvement rate of 1.00% used in the SOA tables was more optimistic than the 0.75% rate published by the SSA in its report “The Long-Range Demographic Assumptions for the 2014 Trustees Report” for ages between 65 and 84. Additionally, the

SOA table uses a 20-year grade-down period to the ultimate assumed rate of improvement. However, a 10-year grade-down period is more consistent with recent experience and with the historical pattern of more rapid changes in the rate of mortality improvement. The SSA has provided actual data from the first three years of the SOA grade-down period to be 1.59% compared to 2.43% for this period in the SOA table.

Therefore, we have determined the SOA mortality tables are not the most appropriate mortality tables to be used in valuing the company's postretirement benefit plans. For our base table, we utilize a table that is based on the SOA RP-2014 mortality but adjust it to remove the post-2007 improvement projections. For our projection scale, we use a projection scale that utilizes the same data and methodology used in the SOA-developed projection scale but modifies it to use a 10-year grade-down period and a 0.75% ultimate annual improvement rate. We believe these tables are more appropriate and reflective of our population.

Holding all other assumptions constant, a 1% decrease in the assumed rate of return on pension plan assets would have increased 2014 after-tax pension cost by approximately $3.6million. Likewise, a 1% decrease in the discount rate assumption would have increased 2014 after-tax pension cost approximately $2.6 million. For 2015, a 1% decrease in the discount rate assumption would result in an approximately $1.9 million after-tax increase in the expected pension cost. A 1% decrease in the assumed rate of return on plan assets would result in an approximately $3.8 million after-tax increase in expected pension cost.

Unrecognized actuarial gains and losses for the pension plan are being recognized over a period of approximately 12 years, which represents the expected remaining service life of the employee group. Unrecognized actuarial gains and losses arise from several factors including experience and assumption changes in the obligations and from the difference between expected return and actual returns on plan assets. These unrecognized gains and losses will be systematically recognized in future net periodic pension expense in accordance with applicable accounting guidance for pensions. The company's policy is to fund the plan based on the required contribution determined by its actuaries within the guidelines set by the ERISA, as amended.

In July 2012, President Obama signed into law the MAP-21. MAP-21 provides funding relief for pension plan sponsors by stabilizing discount rates used in calculating the required minimum pension contributions and increasing PBGC premium rates to be paid by plan sponsors. In August 2014, President Obama signed into law the Highway and Transportation Funding Act of 2014, which delays the phase-out of MAP-21. We plan on funding at levels above the required minimum pension contributions under MAP-21.

In addition, we currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 who meet certain service requirements. We implemented an EGWP for our post-65 retiree prescription drug plan effective Jan. 1, 2013. The EGWP is a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduces net periodic benefit cost by taking advantage of rebate and discount enhancements provided under the Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act (combined the Health Care Reform Acts), which are greater than subsidy payments previously received under Medicare Part D for our post-65 retiree prescription drug plan retiree prescription drug plan. As a result, we ceased receiving Medicare Part D subsidy payments beginning with the 2013 plan year. Effective Jan. 1, 2015, we are changing our post-65 retiree coverage for medical benefits to a Medicare Advantage plan insured by Aetna. This will result in a lower claims cost by taking advantage of the government subsidies available for that plan.

The Health Care Reform Acts contain other provisions that may impact our obligation for retiree medical benefits, including a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. We do not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase our postretirement benefit obligation. We will continue to monitor and assess the potential impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, and on our future results of operations, cash flows or financial position.

The key assumptions used in determining the amount of obligation and expense recorded for postretirement benefits other than pension (OPEB), under the applicable accounting guidance, include the assumed discount rate and the assumed rate of increases in future health care costs. We determine the discount rate for the OPEB the OPEB's projected benefit cash flow. In estimating the health care cost trend rate, we consider our actual health care cost experience, future benefit structures, industry trends, and advice from our outside actuaries. We assume that the relative increase in health care cost will trend downward over the next several years, reflecting assumed increases in efficiency in the health care system and industrywide cost-containment initiatives.

Our assumed health care cost trend rate for medical costs was 7.25% in 2014 and, over time, will decrease to 4.50% in 2025 and thereafter. A 1% increase in the health care trend rates would have produced a $0.2 million after-tax increase in the aggregate service and interest cost for 2014, and an estimated $0.2 million increase in 2015.

The actuarial assumptions used in determining the company's pension and OPEB retirement benefits may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. While we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions may materially affect our financial position or results of operations.

See the discussion of employee postretirement benefits in Note 5 to the TECO Energy Consolidated Financial Statements.

Evaluation of Assets for Impairment

Long-Lived Assets

In accordance with accounting guidance for long-lived assets, we assess whether there has been an impairment of our long-lived assets and certain intangibles held and used when such indicators exist. We normally review all long-lived assets in the last quarter of each year to ensure that any gradual change over the year and the seasonality of the markets are considered when determining which assets require an impairment analysis. However, in the case of a triggering event, such as a significant market disruption or sale of a business, the values of related long-lived assets are reviewed. We believe the accounting estimates related to asset impairments are critical estimates for the following reasons: 1) the estimates are highly susceptible to change, as management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and/or the then current market conditions in such periods; 2) markets can experience significant uncertainties; 3) the estimates are based on the ongoing expectations of management regarding probable future uses and holding periods of assets; and 4) the impact of an impairment on reported assets and earnings could be material. Our assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Our expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

See Note 20 to the TECO Energy Consolidated Financial Statements for discussion of the our treatment of impairment of long-lived assets for the year ended Dec. 31, 2014.

Goodwill

Under the accounting guidance for goodwill, goodwill is not subject to amortization. Rather, goodwill is subject to an annual (or more frequent if events and circumstances indicate a possible impairment) assessment for impairment at the reporting unit level. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. If an entity performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount or if an entity bypasses the qualitative assessment, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Application of the goodwill impairment test requires management judgment, the determination of the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis, a comparable transaction analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, rate case assumptions, utility sector market performance and transactions, projected operating and capital cash flows for the relevant business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

At Dec. 31, 2014, we had $408.3 million of goodwill on our balance sheet, which is reflected in the NMGC segment. This goodwill balance arose from our purchase of NMGC on Sept. 2, 2014. We performed a quantitative assessment in the fourth quarter of 2014, for our annual goodwill impairment assessment. The first step of the impairment assessment comparing the estimated fair value of NMGC to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

Since the purchase price paid for NMGC on Sept. 2, 2014, approximated its fair value, the fair value of NMGC approximated its book value at the annual assessment date. As we identify and incorporate synergies at NMGC, the fair value of NMGC is expected to increase more significantly over its book value. However, certain assumptions used to estimate the fair value of NMGC are highly sensitive to changes. Adverse regulatory actions, such as significant reductions in the allowed ROE at NMGC, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from NMGC's business, and the fair value of debt, could negatively impact goodwill in the future. See Notes 1, 20 and 21 to the TECO Energy Consolidated Financial Statements for additional information.

Purchase Accounting

The excess of the purchase price of an acquired entity over the estimated fair values of assets acquired and liabilities assumed are recognized as goodwill at the acquisition date. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, the utilization of independent valuation experts, and the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. If certain estimates in the valuation vary significantly from actual results in the future, the impairment assessments of goodwill and other assets in the future may be negatively impacted. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. See Note 21 to the TECO Energy Consolidated Financial Statements for additional information.

Regulatory Accounting

Tampa Electric's and PGS's retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. NMGC is subject to regulation by the NMPRC. As a result, the regulated utilities qualify for the application of accounting guidance for certain types of regulation. This guidance recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets and liabilities arise as a result of a difference between GAAP and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred, as their future recovery in customer rates is probable. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

As a result of regulatory treatment and corresponding accounting treatment, we expect that the impact on utility costs and required investment associated with future changes in environmental regulations would create regulatory assets. Current regulation in Florida and New Mexico allows utility companies to recover from customers prudently incurred costs (including, for required capital investments, depreciation and a return on invested capital) for compliance with new environmental regulations through the ECRC (see the Environmental Compliance and Regulation sections).

We periodically assess the probability of recovery of the regulatory assets by considering factors such as regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, the current political climate in the state, and the status of any pending or potential deregulation legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. We believe the application of regulatory accounting guidance is a critical accounting policy since a change in these assumptions may result in a material impact on reported assets and the results of operations (see the Regulation section and Notes 1 and 3 to the TECO Energy Consolidated Financial Statements).

RECENTLY ISSUED ACCOUNTING STANDARDS

Extraordinary and Unusual Items

In January 2015, the FASB issued guidance to remove the concept of extraordinary items from U.S. GAAP. Therefore, events or transactions that are of an unusual nature and occur infrequently will no longer be allowed to be separately disclosed, net of tax, in the income statement after income from continuing operations. The standard is effective for us beginning Jan. 1, 2016. We do not expect a significant impact from the adoption of this guidance.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

In April 2014, the FASB issued guidance regarding changing the criteria for reporting discontinued operations. Under this new guidance, which is intended to enhance convergence of the FASB’s and the IASB’s reporting requirements for discontinued operations, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results. This standard is effective prospectively for us beginning in 2015.

Revenue from Contracts with Customers

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The standard is principle-based and provides a five-step model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This guidance is effective for us beginning in 2017 and allows for either full retrospective adoption or modified retrospective adoption. We are currently evaluating the impact of the adoption of this guidance on our financial statements but do not expect the impact to be significant.

Going Concern

In August 2014, the FASB issued guidance defining management's responsibility to decide whether there is substantial doubt about an organization's ability to continue as a going concern and the related footnote disclosures required. This guidance is effective prospectively for us beginning in 2017. We do not expect any significant impact from the adoption of this guidance on our financial statements.

ENVIRONMENTAL COMPLIANCE

Environmental Matters

Our businesses have significant environmental considerations. Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act, and material Clean Water Act implications and impacts by federal and state legislative initiatives. TEC, through its Tampa Electric and PGS divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. NMGC has not been designated as a PRP and has no former manufactured gas plant sites.

Air Quality Control

Emission Reductions

Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., IGCC) and conversion of coal-fired units to natural-gas fired combined cycle; implementation of a responsible fuel mix taking into account price and reliability impacts to its customers; a substantial capital expenditure program to add BACT emissions controls; implementation of additional controls to accomplish early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

Tampa Electric, through voluntary negotiations in 1999 with the EPA, the U.S. Department of Justice and the FDEP, signed a Consent Decree and Consent Final Judgment, as settlement of federal and state litigation to dramatically decrease emissions from its power plants. Tampa Electric has fulfilled the obligations of the Consent Decree, and the court terminated the Consent Decree on Nov. 22, 2013. Termination of the Consent Final Judgment is in progress and is expected to be completed in 2015.

The emission-reduction requirements of these agreements resulted in the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (Bayside Power Station), enhanced availability of flue-gas desulfurization systems (scrubbers) at Big Bend Station to help reduce $SO_{2,}$ and installation of SCR systems for NO_x reduction on Big Bend Units 1 through 4. Cost recovery for the SCRs began for each unit in the year that the unit entered service through the ECRC (see the Regulation section). Cost recovery for the repowering of the Bayside Power Station was accomplished in Tampa Electric’s 2008 rate case.

As a result of the actions taken under the Consent Decree, emissions of all pollutant types have been significantly reduced. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM emissions from its facilities by 164,000 tons (94%), 63,000 tons (91%) and 4,500 tons (87%), respectively.

Reductions in mercury emissions also have occurred due to the repowering of the Gannon Power Station to the Bayside Power Station. At the Bayside Power Station, where mercury levels have decreased 99% from 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a system-wide reduction of mercury emissions of more than 90% from 1998 levels.

CAIR/CSAPR

As a result of all its completed emission reduction actions, Tampa Electric has achieved the emission-reduction levels called for in Phase I and Phase II of CAIR. In July 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR on emissions of SO_2 and NO_x. The federal appeals court reinstated CAIR in December 2008 on an interim basis. In July 2011, the EPA issued the final CAIR replacement rule, called the CSAPR. The final CSAPR focused on reducing SO_2 and NO_x in 27 eastern states that contribute to ozone and/or fine particle pollution in other states. Compliance with CSAPR, which would be measured at the individual power plant level, would require the addition of scrubbers or SCRs on most coal-fired power plants. In addition, the rule utilized intrastate emissions allowance trading and limited interstate emissions allowance trading to achieve compliance. All of Tampa Electric’s conventional coal-fired units are already equipped with scrubbers and SCRs, and the Polk Unit 1 IGCC unit removes SO_2 in the gasification process.

The EPA has estimated that the implementation of CSAPR would result in the retirement of primarily smaller, older coal-fired power stations that do not currently have state-of-the-art air pollution control equipment already installed. The retirement of these units or switching to other fuels for compliance with this rule is likely to reduce overall demand for coal, which could reduce sales at TECO Coal.

On Dec. 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit granted the motion to stay the implementation of CSAPR in all aspects, which had been scheduled to take effect Jan. 1, 2013, and ordered the reinstatement of CAIR pending the outcome of the litigation. On Aug. 21, 2012, the court vacated CSAPR entirely and remanded it back to the EPA while leaving the CAIR in place. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing an Aug. 21, 2012 D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, the EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On Oct. 23, 2014, the D.C. Circuit granted the EPA's request. Effective January 1, 2015, CSAPR Phase 1 replaced CAIR. Phase 2 of the CSAPR is expected to be implemented in 2017.

SO_2 National Ambient Air Quality Standards (NAAQS)

On June 2, 2010, the EPA revised the primary SO_2 NAAQS by establishing a new 1-hour standard at a level of 75 parts per billion (ppb). A part of Hillsborough County north of Big Bend Station has a monitor that violates the 2010 SO_2 NAAQS. Although Big Bend Station did not contribute to the violation, it has potential effects on the non-attainment area based on air dispersion modeling evaluations and has committed to accept a more stringent SO_2 permit limit to ensure the area achieves compliance with the ambient air standards.

The next phase of the SO_2 NAAQS process will address all ambient SO_2 exceedences located outside the designated non-attainment areas. Air dispersion modeling or ambient air monitoring will be used to determine impacts to these areas beginning no earlier than 2018 but no later than 2021. Additional SO_2 emission reductions may be required depending on the outcome of this process.

Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT)

The EPA published proposed rules under National Emission Standards for HAPS on May 3, 2011, pursuant to a court order. These rules are expected to reduce mercury, acid gases, organics, and certain non-mercury metals emissions and require MACT. The final Utility MACT rules, now called Mercury Air Toxics Standards (MATS), were published in December 2011 with implementation called for in early 2015 with possible extensions to early 2016 or 2017 under certain specific criteria. A potential outcome of the MATS rule is the retirement of smaller, older coal-fired power plants that do not already have emissions controls installed.

All of Tampa Electric’s conventional coal-fired units are already equipped with scrubbers and SCRs, and the Polk Unit 1 IGCC unit emissions are minimized in the gasification process. Tampa Electric is uniquely positioned to be able to meet the new standards without considerable impacts, compared to others who have not taken similar early actions. Therefore, Tampa Electric expects the co-benefits of these control devices for mercury removal to minimize the impact of this rule and expects that it will be in compliance with MATS with nominal additional capital investment. The retirement of coal-fired generating units as a result of the implementation of this rule could reduce demand for sales at TECO Coal.

Carbon Reductions and GHG

Tampa Electric has historically supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce overall emissions at Tampa Electric’s facilities. Since 1998, Tampa Electric has reduced its system wide emissions of CO_2 by approximately 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 to remain near 1990 levels until the addition of the next base load unit, which is scheduled to be in service in January 2017 (see the Tampa Electric and Capital Expenditures sections). Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same time frame, the numbers of retail customers and retail energy sales have risen by approximately 30% and 15%, respectively.

Tampa Electric’s power plants currently emit approximately 16 million tons of CO_2 per year. Assuming a projected long-term average annual load growth of more than 1.0%, Tampa Electric could emit approximately 16.3 million tons of CO_2 (an increase of approximately 2%) by 2020 if natural gas-fired peaking and combined-cycle generation additions are used to meet customer demand.

In 2010, the EPA issued its Final Rule on the mandatory reporting of GHGs, requiring facilities that emit 25,000 metric tons or more of CO_2, or its equivalent, per year to begin collecting GHG data under a new reporting system on Jan. 1, 2010, with the first annual report due Sept. 28, 2011. Tampa Electric complied with the mandatory reporting requirement, in large part through the methods and procedures already utilized, and continues to submit annual reports as required. The rule also required natural gas distribution, underground coal mining facilities, and electric transmission and distribution companies, including PGS, TECO Coal and Tampa Electric, that emit 25,000 metric tons or more of CO_2, or its equivalent, per year to begin collecting GHG data under a new reporting system on Jan. 1, 2011, with the first annual report due Sept. 28, 2012. Tampa Electric complied with the reporting requirement and continues to submit annual reports as required.

In December 2009, the EPA published the final Endangerment Finding in the Federal Register. Although the finding was technically made in the context of GHG emissions from new motor vehicles and did not, in itself, impose any requirements on industry or other entities, the EPA claims that the finding triggered GHG regulation of a variety of sources under the Clean Air Act (CAA). Related to utility sources, the EPA's "tailoring rule," which addresses the GHG emission threshold triggers that would require permitting review of new and/or major modifications to existing stationary sources of GHG emissions, became effective Jan. 2, 2011. A recent U. S. Supreme Court ruling narrowed the EPA's authority to implement this rule but the key provisions remain applicable to Tampa Electric. While this rule does not have an immediate impact on Tampa Electric's ongoing operations, GHG permitting was recently completed for Tampa Electric's next base load unit, the Polk Unit 2 – 5 conversion to combined cycle.

In June 2013, President Obama announced his "Climate Action Plan" a broad package of mostly administrative initiatives aimed at reducing GHG emissions by approximately 17% below 2005 levels by 2020. As part of the Climate Action Plan, the President directed the EPA to issue a draft rule for existing power plants by June 1, 2014, to finalize the rule by June 1, 2015, and to require states to submit implementation plans by June 30, 2016. In response to this directive, on June 2, 2014, the EPA released a comprehensive proposed rule, which it calls the "Clean Power Plan," aiming to cut GHG emissions from existing power plants by an average across all states of 30% from their 2005 levels by 2030, with an interim goal for the period from 2020 through 2029. Based on current emissions, Florida has a higher reduction goal than the average, of 38%. Under the proposed rule, each state would have to reduce carbon dioxide emissions on a state-wide basis by an amount specified by the EPA; the target amount was determined by the EPA's view of each state's options, including: making power plant efficiency upgrades; shifting from coal-fired to natural gas-fired generation; investing in zero- and low-emitting power sources, such as renewable and nuclear energy; and implementing customer energy efficiency programs. States are intended to have a great deal of flexibility in designing programs to meet their emission reduction targets, including the four approaches noted above or any other measures they choose to adopt, for example, carbon tax and cap-and-trade. The EPA is now scheduled to finalize the rule by the summer of 2015, and states will have until June 30, 2016, to submit plans to implement the finalized rule (subject to extension and EPA approval of the states' plans). The outcome of this rule-making process and its impact on our businesses cannot be determined at this time; however, it could result in increased operating costs, or decreased operations at Tampa Electric's coal-fired plants. Depending on how they are enacted, the proposed rules could increase our costs or the rates charged to our customers, which could curtail sales. See Item 1A - Risk Factors.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but cannot predict whether the FPSC would grant such recovery. Tampa Electric's current solid-fuel energy generation was about 55% of its total system output in 2014, compared to being approximately 84% of its output in 2001. This is due to the conversion of the coal-fired Gannon Power Station into the natural gas-fired Bayside Power Station. However, solid fuel-fired facilities remain a significant component of Tampa Electric's diverse generation fleet and additional solid fuel units could be considered in the future.

In the case of TECO Coal, there are not yet federal limits on GHG emissions for this sector, and it is unclear if future requirements for GHG emissions reductions would directly impact it as a carbon-based fuel provider or the end users of its products. In either case, these requirements could make the use of coal more expensive or less desirable, which could impact TECO Coal's margins and profitability.

Water Supply and Quality

The EPA's final Clean Water Act Section 316(b) rule took effect in 2004. The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. Tampa Electric uses water from Tampa Bay at its Bayside and Big Bend facilities as cooling water. Both plants use mesh screens to reduce the adverse impacts to aquatic organisms, and Big Bend units 3 and 4 use proprietary fine-mesh screens, BACT, to further reduce impacts to aquatic organisms. Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. In 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The Supreme Court agreed to review the Second Circuit's decision and heard arguments in December 2008. The EPA decided to rewrite the rule, and proposed a new rule in the summer of 2013. After several delays, the final rule was released in 2014. The full impact of the new regulations will depend on subsequent legal proceedings, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies.

On Dec. 6, 2010, the EPA published its final rule, setting numeric nutrient criteria for Florida's lakes and flowing waters. The rule, as published, is being challenged in the courts by numerous parties, including the state of Florida. The rule sets numeric limits for nitrogen and phosphorous in lakes and streams and for nitrate plus nitrite in springs. The EPA promulgated the rule pursuant to the terms of a consent decree approved by the U.S. District Court in Florida Wildlife Federation v. Jackson, in which environmentalists sued the EPA for allegedly violating a duty under the Federal Water Pollution Control Act (Clean Water Act or Act) to set the numeric criteria. In response to comments raising numerous implementation concerns, the EPA decided to delay the effective date of the criteria until 15 months after publication. The EPA announced that, in the interim, it would undertake a series of implementation steps in Florida, including an "education and outreach rollout," training meetings, and the development of guidance materials to coincide with the expected comment period on proposed site-specific alternative criteria. On Nov. 30, 2012, the EPA approved the FDEP rule in its entirety. The EPA proposed additional criteria in December 2012, including a re-proposal of streams criteria that were previously invalidated by the Court. In January 2014, the EPA consent decree was revised allowing only the FDEP criteria to be implemented in Florida. Additional litigation was filed in 2014 challenging the legality of the revision of the consent decree; oral arguments occurred in January 2015, but there has been no final ruling. Streams criteria may still directly affect Polk Power Station's cooling reservoir discharge to surface water, and may require the station to reduce the amount of nutrients in the cooling reservoir water before discharge.

After the completion of a study into wastewater discharges by the electric utility industry in 2009, the EPA announced its intent to revise the existing steam electric effluent limit guidelines (ELGs) that place technology-based limits on wastewater discharges. The final rulemaking is scheduled for September 2015 and is expected to focus on wastewater discharges from scrubbers, fly ash and bottom ash sluicing processes, leachate from ponds and landfills containing CCRs, IGCC processes, and flue gas mercury controls. The EPA is evaluating a suite of technology options which include treatment processes for wastewater discharges as well as the conversion to dry handling of fly ash and bottom ash to allow for zero discharge of transport water. Final impacts will vary depending on the mandated technology, the volume of wastewater to be treated and the pollutant limits. Tightened limits are anticipated for mercury, selenium, trace metals, and chlorides. New guidelines will likely add stricter limits to future NPDES permits in 2014-2019 (based on the five-year permit cycle).

Section 404 of the Clean Water Act and Coal Surface Mine Permits

Since 2008, the issuance of permits by the USACE under Section 404 of the Clean Water Act required for surface mining activities in the Central and Northern Appalachian mining regions has been challenged in the courts by various environmental groups.

On April 1, 2010, the EPA issued new guidance on environmental permitting requirements for Appalachian mountaintop removal and other surface mining projects. The guidance limits conductivity (level of mineral salts) in water discharges into streams from permitted areas, and was effective immediately on an interim basis. In July 2011, the EPA made this guidance final without modification. Because the EPA's standards appear to be unachievable under most circumstances, surface mining activity could be substantially curtailed since most new and pending permits would likely be rejected. This guidance could also be extended to discharges from deep mines and preparation plants, which could result in a substantial curtailing of those activities as well.

This guidance was challenged in the courts by a number of coal mining industry-related organizations, states and municipalities relating to the stringency of the standards as well as the focus on the coal industry and the Appalachian region in particular. In July 2012, the U. S. District Court for the District of Columbia ruled that the EPA had exceeded its statutory authority in establishing the water quality guidance discussed above. Following the outcome of this court decision, pending appeals by the EPA, few, if any, new permits have been issued by USACE. See Item 1A – Risk Factors.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2014, TEC has estimated its ultimate financial liability to be $33.3 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other" on the Consolidated Condensed Balance Sheets. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC's experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's actual percentage of the remediation costs.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Coal Combustion Residuals Recycling and Disposal

The combustion of coal at two of Tampa Electric's power-generating facilities, the Big Bend and Polk Power stations, produces ash and other by-products, collectively known as Coal Combustion Residuals (CCRs). The CCRs produced at Big Bend include fly ash, FGD gypsum, boiler slag, bottom ash and economizer ash. The CCRs produced at the Polk Power Station include gasifier slag and sulfuric acid. Overall, over 97% of all CCRs produced at these facilities were marketed to customers for beneficial use in commercial and industrial products. The remaining 3% were either disposed of onsite or shipped offsite to nearby industrial waste landfills in Central Florida.

In response to a coal ash pond failure at another utility in December 2008, the EPA proposed new regulations for the management and disposal of CCRs. A preliminary draft of the final rule was issued in December 2014 and, as expected does not designate CCRs as hazardous waste. However, the rule does regulate CCR waste as non-hazardous solid waste while also explicitly allowing for encapsulated beneficial uses in commercial and industrial products. Conversely, non-encapsulated uses in agricultural and construction applications are subject to new criteria in order to be allowed as legitimate beneficial uses. Projects constructed under previous beneficial use determinations by state agencies do not have to be reevaluated against these criteria.

The rule, which also includes many other administrative and compliance requirements for both new and existing CCR management facilities, is expected to be published in the Federal Register in the first quarter of 2015. It is currently undergoing intense analysis by industry associations and state agencies, with meetings scheduled in in the near future to discuss its requirements. As expected, the rule is modeled after the existing Subtitle D rules for non-hazardous waste, with some special requirements for disposal of CCRs in surface impoundments and landfills.

Renewable Energy

Renewables are a component of Tampa Electric’s environmental portfolio. Tampa Electric’s renewable energy program offers to sell renewable energy as an option to customers and utilizes energy generated in the state from renewable sources (e.g. biomass and solar). To date, almost 70 million kWh of renewable energy have been produced by Tampa Electric and other renewable energy generating sources within Florida to support participating customer requirements.

Tampa Electric has installed 135 kW of solar panels to generate electricity from the sun at seven community sites including two schools, Tampa Electric’s Manatee Viewing Center, the Museum of Science and Industry, Tampa’s Lowry Park Zoo, the Florida Aquarium, and most recently LEGOLAND Florida. The company continues to evaluate opportunities to increase its solar portfolio. Tampa Electric plans to install its first, large-scale solar facility at Tampa International Airport by the end of 2015. At 2 megawatts, the solar panels will produce enough electricity to power up to 250 homes. Tampa Electric will own the solar PV array and the electricity it produces will go to the grid to benefit all Tampa Electric customers, including the airport.

In Florida, once again there are proposals for consideration in the state’s next legislative session (Mar. 3 through May 1, 2015) to encourage and support increasing supplies of energy from renewable sources, primarily roof-top solar generation from non-utility sources. These proposals did not pass in prior legislative sessions and, at this time, we cannot determine if they will pass in 2015.

Distributed Generation

In many areas of the country there is growing use of rooftop solar panels, small wind turbines and other small-scale methods of power generation, called distributed generation, by individual residential, commercial and industrial customers. Distributed generation is encouraged and supported by various special interest groups, tax incentives, renewable portfolio standards and special rates designed to support such generation. To date, there has not been a significant amount of distributed generation added to utility systems in Florida. Florida does not have a renewable portfolio standard, and Florida legislation and regulation have minimized social programs and costs in utility rates. However, proposed action by the Florida legislature in 2015 and a potential amendment to the Florida constitution in 2016 would encourage the installation of solar arrays to generate electricity by retail customers and third parties, and to allow limited sales of electricity by non-utility generators.

Additionally, the EPA’s proposed “Clean Power Plan” rule, if enacted as proposed, could have the effect of providing greater incentives for distributed generation in order to meet state-based emission reduction targets. See Item 1A - Risk Factors. Depending on how the rule is finally adopted, it could have the effect of increasing our costs or the rates charged to our customers, which could curtail sales.

Increased usage of distributed generation, particularly in those states where solar or wind resources are the most abundant, is reducing utility electricity sales, but not reducing the need for ongoing investment in infrastructure to maintain or expand the transmission and distribution grid to reliably serve customers. Due to the intermittent availability of renewable resources, utilities must invest in adequate generating resources to meet customer demand at the times that renewable resources are not available. Energy storage technologies, such as batteries, are not yet commercially available to fill this demand. Continued utility investment not supported by increased future energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

Conservation

Energy conservation is becoming more important in the GHG emissions reduction debate. Tampa Electric supports the FPSC and its objectives toward increasing energy efficiency. In 2014, Tampa Electric continued to offer its customers a comprehensive array of residential and commercial programs that enabled the company to meet its required DSM goals, reduce weather-sensitive peak demand and conserve energy. This strategy continues to allow Tampa Electric to delay construction of future generation facilities. Since their inception, the company’s conservation programs have reduced the summer peak demand by 331 MW and the winter peak demand by 723 MW.

In November 2014, the FPSC established new demand-side-management (DSM) goals for 2015 to 2024 for all Florida investor-owned electric utilities. In the goal setting process, all of the Florida investor-owned utilities sought permission from the FPSC to lower the DSM goals. The primary drivers for the lower DSM goals were: 1) lower overall annual customer growth and lower per customer electricity usage, which defers the in-service date for the next generating unit, 2) decreased costs of utility natural gas fired generation, 3) increased efficiency of air conditioners, appliances and lighting, which have reduced the available demand and energy savings that can be achieved through DSM programs.

While the new approved goals for Tampa Electric are lower, the goals are reasonable, beneficial and cost-effective to all customers as required by the Florida Energy Efficiency & Conservation Act (FEECA). For Tampa Electric, the new summer and winter demand goals are 56.9 and 87.4 MWs, respectively, and the energy goal is 144.3 gigawatt-hours over the 10-year period. Establishing these DSM goals for the 10-year period is required every five years. These programs and their costs are approved annually by the FPSC with the costs recovered through a clause on the customer’s bill. In addition, PGS offers conservation programs that enable customers to reduce their energy consumption, with those costs recovered through a clause on customers’ gas bill.

REGULATION

Tampa Electric’s and PGS’s retail operations are regulated by the FPSC, which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices, and other matters. NMGC is subject to regulation by the NMPRC. The NMPRC has jurisdiction over the regulatory matters related, directly and indirectly, to NMGC providing service to its customers, including, among other things, rates, accounting procedures, securities issuances, and standards of service.

In general, for retail services, the FPSC and NMPRC’s objective is to provide reliable service at fair and reasonable rates. The objective is to set rates at a level that provides an opportunity for the utility to collect total revenues (revenue requirements) equal to its cost to provide service, plus a reasonable return on invested capital.

For the electric and gas utilities, the costs of owning, operating and maintaining the utility systems, excluding fuel and conservation costs as well as purchased power and certain environmental costs for the electric system, are recovered through base rates. These costs include O&M expense, depreciation and taxes, as well as a return on investment in assets used and useful in providing electric and natural gas distribution services (rate base). In Florida, the rate of return on rate base, which is intended to approximate the individual company’s weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero-cost rate and an allowed ROE. In New Mexico, the rate of return on rate base, which is intended to approximate the individual company’s weighted cost of capital, primarily includes its costs for long-term debt and an allowed ROE. Base rates are determined in FPSC or NMPRC revenue requirement and rate setting hearings which occur at irregular intervals at the initiative of the utilities, FPSC, NMPRC or other parties.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services, and accounting practices.

Federal, state and local environmental laws and regulations cover air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters (see the Environmental Compliance section).

Tampa Electric - Base Rates

In 2011, 2012 and 2013 prior to Nov. 1, the rates and allowed ROE in effect for Tampa Electric had been established in 2009 and in a series of subsequent decisions in 2009 and 2010. The allowed ROE during this period was a range of 10.25% to 12.25%, with a midpoint of 11.25%.

As a result of growth in rate base from required infrastructure added to serve customers, increasing pressure on O&M expense, and an economic recovery that was slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding in 2009, on April 5, 2013, Tampa Electric filed its petition with the FPSC for an increase in base rates and miscellaneous service charges in the amount of $134.8 million. In the petition, Tampa Electric requested an ROE level of 11.25% and a capital structure identical to that approved in 2009, with 54% equity.

After extensive testimony by Tampa Electric and discovery by five intervening parties and the FPSC Staff, on Sept. 6, 2013, Tampa Electric and all of the intervening parties reached a Stipulation and Settlement Agreement resolving all of the issues in the proceeding.

On Sept. 11, 2013, the FPSC approved the Settlement that authorized base rate increases implemented at four different dates.

1. Nov. 1, 2013: $57.5 million increase
2. Nov. 1, 2014: Additional $7.5 million increase ($65 million cumulative)
3. Nov. 1, 2015: Additional $5 million increase ($70 million cumulative)
4. Jan. 1, 2017: Implementation of a Generation Base Rate Adjustment representing a $110 million additional increase on Jan. 1, 2017, or on the in-service date of the Polk 2-5 conversion, whichever is later.

The Settlement authorized an ROE of 10.25% and equity ratio of 54%, with a provision that ROE becomes 10.50% if at any time during the agreement the six month average 30-year U.S. Treasury Bond yield increases 75 basis points. Base rates will not change if the ROE trigger were to take effect; however, for purposes of cost recovery clauses, AFUDC and surveillance reporting, there would be an adjustment to reflect the 10.50%.

As part of the settlement, Tampa Electric discontinued its annual $8 million storm damage expense accrual at Nov. 1, 2013, and the company will utilize a 15-year amortization period for all software retroactive to Jan. 1, 2013. The company will not be able to file for new base rates to be effective sooner than Jan. 1, 2018, subject to a bilateral opportunity for Tampa Electric or interveners to initiate a rate proceeding if actual reported ROE falls below a floor of 9.25% or above a ceiling of 11.25%, subject to the 25 basis point incremental ROE if triggered. Lastly, the company is required to file a depreciation study no fewer than 60 days but no more than one year before filing its next base rate request.

The settlement also contained various changes with respect to rate design. The company implemented a new Commercial and Industrial Service Rider (CISR) and an Economic Development Rate. The new Economic Development Rate was implemented on a pilot basis for a three-year period and limited by the maximum amount of economic development expenditures as specified in Commission rules, which is approximately $3 million. The current lock-in period for interruptible credits will extend from three to six years and the Standby Generator credit will be adjusted from $4.00 to $4.75.

Tampa Electric Cost-Recovery Clauses

In November 2014, the FPSC approved Tampa Electric’s rates for the various cost-recovery clauses for 2015. Tampa Electric’s fuel filing reflected continued low natural gas prices as well as good unit performance and an over recovery of 2014 fuel costs, and reductions in the conservation and ECRC clauses, which resulted in Tampa Electric seeking a total $1.75 reduction in all of its clauses for 2015 for a residential customer using 1,000 kWh per month. As of Jan. 1, 2015, the total bill for a residential customer using 1,000 kWh was $108.39, compared to the December 2014 bill of $110.14.

Utility Competition – Electric

Tampa Electric’s retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing high quality service to retail customers.

Unlike the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including other IOUs, municipal and other utilities, as well as co-generators or other unregulated power generators with uncontracted excess capacity. Entities compete to provide energy on a short-term basis (i.e., hourly or daily) and on a longer term basis. Competition in these markets is primarily based on having available energy to sell to the wholesale market and the price. In Florida, available energy for the wholesale market is affected by the state's PPSA, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam or solar capacity of 75 MW or more. The PPSA requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. The effect of the PPSA has been to limit the number of unregulated generating units with excess capacity for sale in the wholesale power markets in Florida.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring IOUs, such as Tampa Electric, to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle or solar installation greater than 75 MW. The rules, which allow independent power producers and others to bid to supply the new generating capacity, provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids, and provide more stringent standards for the IOUs to recover cost overruns in the event the self-build option is deemed the most cost-effective.

In many areas of the country there is growing use of rooftop solar panels, small wind turbines and other small scale methods of power generation, called distributed generation, by individual residential, commercial and industrial customers, or by third-party developers. Distributed generation is encouraged and supported by various special interest groups, tax incentives, renewable portfolio standards and special rates designed to support such generation. Tampa Electric offers rebate programs of up to $1.5 million annually to encourage development of solar installations and third-party developers offer attractive financing and leasing arrangements to encourage project development. As approved in the DSM proceeding in November 2014 (see Environmental Compliance - Conservation), the $1.5 million rebate program will end in 2015. In Florida, third parties that are not subject to regulation by the FPSC are not permitted to make direct sales of electricity to end use customers. The allowance of direct third party sales would require action by the Florida legislature, which is not expected to be taken in its 2015 session, or a constitutional amendment.

PGS Rates

PGS's rates and allowed ROE range of 9.75% to 11.75%, with a midpoint of 10.75%, and an equity ratio of 54.7%, which was established in 2009, are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by PGS, FPSC or other interested parties.

PGS Cost-Recovery Clauses

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the PGA clause. This clause is designed to recover the costs incurred by PGS for purchased gas, and for holding and using interstate pipeline capacity for the transportation of gas it delivers to its customers. These charges may be adjusted monthly based on a cap approved annually during an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a calendar year recovery period, with a true-up adjustment to reflect the variance of actual costs and usage to projected charges for prior periods. In November 2014, the FPSC approved PGS' request for its PGA cap factor of $0.98354 per therm effective for 2015. In addition to base rates and PGA clause charges, PGS customers (except interruptible customers) also pay a per-therm conservation charge for all gas. This charge is intended to permit PGS to recover costs incurred in developing and implementing energy conservation programs, which are mandated by Florida law and approved and supervised by the FPSC. PGS is permitted to recover, on a dollar-for-dollar basis, prudently incurred expenditures made in connection with these programs if it demonstrates the programs are cost-effective for its ratepayers.

In 2012, the FPSC approved a Cast Iron/Bare Steel Pipe Replacement Rider to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. Utilities nationwide have been encouraged by the U.S. Department of Transportation to replace this older infrastructure as a safety measure. The FPSC approved PGS' request to accelerate the replacement program of approximately 5%, or 500 miles, of the PGS system at a cost of approximately $80 million over a 10-year period.

Utility Competition – Gas, Florida

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity, propane and fuel oil. PGS has taken actions to retain and expand its natural gas distribution business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. PGS has a "NaturalChoice" program, offering unbundled transportation service to all eligible customers and allowing non-residential customers and residential customers using more than 1,999 therms annually to purchase commodity gas from a third party but continue to pay

PGS for the transportation. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 21,900 transportation-only customers as of Dec. 31, 2014, out of approximately 36,000 eligible customers

NMPRC

Unlike the FPSC, which is appointed by the Governor of Florida and approved by the Florida Senate, the NMPRC is made up of five elected commissioners, each representing a specific geographic region of the state. NMPRC commissioners are elected to four-year terms. Commissioners are required to have at least 10 years of professional experience in areas regulated by the NMPRC or in the energy sector and involving accounting, public or business administration, economics, finance, statistics, engineering or law. The 10-year experience requirement can include the time spent earning the professional license or degree from an accredited institute of higher learning in the areas described above. In addition, ethic certification and continuing education requirements are mandated by New Mexico law.

Historically the NMPRC had used historical test periods in determining new rates; however legislation was enacted in 2009 that allows the NMPRC to utilize forecasted test periods. The first fully litigated case utilizing a forecasted test period was decided in 2014.

NMGC Rates

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC's base rates by approximately $34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on Jan. 31, 2012, revising, among other things, base rates for all service provided on or after Feb. 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC's base rate revenue by approximately $21.5 million on a normalized annual basis. The monthly residential customer access fee increased from $9.59 to $11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017. In addition under the order NMGC will provide $2.0 million of pretax credits on customer bills for the first 12-month period post-closing, effective Oct. 1, 2014, and $4.0 million of credits to customers in each subsequent 12-month period until new base rates are effective. See Note 21 to the TECO Energy Consolidated Financial Statements.

NMGC Cost-Recovery Clauses

Like PGS, NMGC recovers the costs it pays for virtually all of its gas supply, storage and interstate transportation for system supply through the PGAC. Under this mechanism, customers that receive commodity gas from NMGC are charged a rate that allows NMGC to recover its actual cost of gas sold to those customers on a near real-time basis at no profit. This charge is adjusted on a monthly basis, based on the expected cost of gas and any prior month under-recovery or over-recovery of the cost of gas. NMGC may also include a simple interest charge or credit depending on any under-recovery or over-recovery of the cost of gas.

NMGC's annual PGAC period runs from Sept. 1 to Aug. 31. The NMPRC requires that NMGC file a reconciliation of the PGAC period costs and recoveries, in December of each year. NMGC must file a PGAC Continuation Filing with the NMPRC every four years. The most recent PGAC Continuation Filing was submitted to the NMPRC in June 2012. The purpose of the PGAC Continuation Filing is to establish that the continued use of the PGAC is reasonable and necessary. In January 2013, the NMPRC approved NMGC's June 2012 PGAC Continuation Filing, which allows for the continued use of the PGAC for another four years.

NMGC's cost of gas sold is charged to customers with no mark-up and, therefore, NMGC does not earn any profit on the gas commodity reflected on customer bills. Despite the fact that NMGC does not earn any profit on the commodity gas, this cost may generate significant increases or decreases in NMGC's revenues, due to changes in the market price of natural gas, and corresponding increases or decreases in the cost of natural gas sold, a component of NMGC's operating expenses.

In addition to base rates and PGAC clause charges, NMGC's residential customers and customers utilizing NMGC's small and medium volume general services also pay a per-therm charge for energy conservation. This charge is intended to permit NMGC to recover costs incurred in developing and implementing energy conservation programs, which are mandated by New Mexico law and approved and supervised by the NMPRC every two years. NMGC is permitted to recover, on a dollar-for-dollar basis, prudently incurred expenditures made in connection with these programs if it demonstrates the programs are cost-effective for its customers.

Utility Competition – Gas, New Mexico

Although NMGC is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity, propane and fuel oil. NMGC has taken actions to retain and expand its natural gas distribution business, including managing costs and providing high quality service to customers.

NMGC is required to provide transportation-only services for all customer classes. As a result, NMGC receives its base rates for distribution gas delivery services regardless of whether a customer elects transportation-only service or continues as a customer of NMGC's gas commodity sales service. As of Dec. 31, 2014, NMGC had approximately 4,030 transportation-only customers and approximately 511,000 gas commodity sales service end-use customers.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Risk Management Infrastructure

We are subject to various types of market risk in the course of daily operations, as discussed below. We have adopted an enterprise wide approach to the management and control of market and credit risk. Middle Office risk management functions, including credit risk management and risk control, are independent of each transacting entity (Front Office).

Our Risk Management Policy (Policy) governs all energy transacting activity at the TECO Energy group of companies. The Policy is approved by our board of directors and administered by a Risk Authorizing Committee (RAC) that is comprised of senior management. Within the bounds of the Policy, the RAC approves specific hedging strategies, new transaction types or products, limits, and transacting authorities. Transaction activity is reported daily and measured against limits. For all commodity risk management activities, derivative transaction volumes are limited to the anticipated volume for customer sales or supplier procurement activities.

The RAC also administers the Policy with respect to interest rate risk exposures. Under the Policy, the RAC operates and oversees transaction activity. Interest rate derivative transaction activity is directly correlated to borrowing activities.

Risk Management Objectives

The Front Office is responsible for reducing and mitigating the market risk exposures that arise from the ownership of physical assets and contractual obligations, such as debt instruments and firm customer sales contracts. The primary objectives of the risk management organization, the Middle Office, are to quantify, measure, and monitor the market risk exposures arising from the activities of the Front Office and the ownership of physical assets. In addition, the Middle Office is responsible for enforcing the limits and procedures established under the approved risk management policies. Based on the policies approved by the company's board of directors and the procedures established by the RAC, from time to time, our companies enter into futures, forwards, swaps and option contracts to limit the exposure to items such as:

- Price fluctuations for physical purchases and sales of natural gas in the course of normal operations at our electric and gas utilities; and
- Interest rate fluctuations on debt of TECO Energy and its affiliates.

Our companies use derivatives only to reduce normal operating and market risks, not for speculative purposes. Our primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers.

Fair Value Measurements

The company has adopted the accounting standards for fair value measurement. These standards define fair value, establish a framework for measuring fair value under GAAP, and expand disclosures about financial assets and liabilities carried at fair value. The majority of the company's financial assets and liabilities are in the form of natural gas, heating oil or interest rate derivatives classified as cash flow hedges. This adoption did not have a material impact on our results of operations, liquidity or capital.

Most natural gas derivatives were entered into by the regulated utilities to manage the impact of natural gas prices on customers. As a result of applying the provisions of accounting standards for regulated activities, the changes in value of natural gas derivatives of Tampa Electric, PGS and NMGC are recorded as regulatory assets or liabilities to reflect the impact of the risks of hedging activities in the fuel recovery clause. Because the amounts are deferred and ultimately collected through the fuel recovery clause, the unrealized gains and losses associated with the valuation of these assets and liabilities do not impact our results of operations.

Heating oil and diesel fuel hedges were used to mitigate the fluctuations in the price of diesel fuel, which was a significant component in the cost of coal production at TECO Coal and its subsidiaries.

The valuation methods we used to determine fair value are described in Note 17 to the TECO Energy Consolidated Financial Statements.

Credit Risk

We have a rigorous process for the establishment of new trading counterparties. This process includes an evaluation of each counterparty’s financial statements, with particular attention paid to liquidity and capital resources; establishment of counterparty specific credit limits; optimization of credit terms; and execution of standardized enabling agreements. Our Credit Guidelines require transactions with counterparties below investment grade to be collateralized.

Contracts with different legal entities affiliated with the same counterparty are consolidated for credit purposes and managed as appropriate, considering the legal structure and any netting agreements in place. Credit exposures are calculated, compared to limits and reported to management on a daily basis. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

We have implemented procedures to monitor the creditworthiness of our counterparties and to consider nonperformance in valuing counterparty positions. Net liability positions are generally not adjusted as we use our derivative transactions as hedges and we have the ability and intent to perform under each of our contracts. In the instance of net asset positions, we consider general market conditions and the observable financial health and outlook of specific counterparties, forward-looking data such as credit default swaps when available and historical default probabilities from credit rating agencies in evaluating the potential impact of nonperformance risk to derivative positions.

Certain of our derivative instruments contain provisions that require our debt, or in the case of derivative instruments where TEC is the counterparty, TEC's debt, to maintain an investment-grade credit rating from any or all of the major credit rating agencies. If our debt ratings, including TEC's, were to fall below investment grade, it could trigger these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features were in liability positions on Dec. 31, 2014. If the credit-risk related contingent features underlying these agreements were triggered as of Dec. 31, 2014, we could have been required to post collateral or settle existing positions with counterparties totaling $42.7 million. In the unlikely event that this situation would occur, we believe that we maintain adequate lines of credit to meet those obligations.

Interest Rate Risk

We are exposed to changes in interest rates primarily as a result of our borrowing activities. We may enter into futures, swaps and option contracts, in accordance with the approved risk management policies and procedures, to moderate this exposure to interest rate changes and achieve a desired level of fixed and variable rate debt. As of Dec. 31, 2014 and 2013, a hypothetical 10% increase in the consolidated group's weighted-average interest rate on its variable rate debt during the subsequent year would not result in a material impact on pretax earnings. This is driven by the low amounts of variable rate debt at TECO Energy and at our subsidiaries. A hypothetical 10% decrease in interest rates would increase the fair market value of our long-term debt by approximately 2.8% at Dec. 31, 2014 and 2013 (see the Financing Activity section and Notes 6 and 7 to the TECO Energy Consolidated Financial Statements). These amounts were determined based on the variable rate obligations existing on the indicated dates at TECO Energy and its subsidiaries. The above sensitivities assume no changes to our financial structure and could be affected by changes in our credit ratings, changes in general economic conditions or other external factors (see the Risk Factors section).

Commodity Risk

We and our affiliates face varying degrees of exposure to commodity risks including coal, natural gas, fuel oil and other energy commodity prices. Any changes in prices could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. Management uses different risk measurement and monitoring tools based on the degree of exposure of each operating company to commodity risks.

Regulated Utilities

Historically, Tampa Electric's fuel costs used for generation were affected primarily by the price of coal and, to a lesser degree, the cost of natural gas and fuel oil. With the repowering of the Bayside Power Station, the use of natural gas, with its more volatile pricing, has increased substantially. PGS and NMGC have exposure related to the price of purchased gas and pipeline capacity.

Currently, our electric and gas utilities' commodity price risks are largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through FPSC or NMPRC-approved cost-recovery clauses, with no anticipated effect on earnings. However, increasing fuel cost-recovery has the potential to affect total energy usage and the relative attractiveness of electricity and natural gas to consumers. To moderate the impact of fuel price changes on customers, our electric and gas utilities manage commodity price risk by entering into long-term fuel supply agreements, prudently operating plant facilities to optimize cost, and entering into derivative transactions designated as cash flow hedges of anticipated purchases of wholesale natural gas. At Dec. 31, 2014 and 2013, a change in commodity prices would not have had a material impact on earnings for Tampa Electric, PGS or NMGC, but could have had an impact on the timing of the cash recovery of the cost of fuel (see the Tampa Electric and Regulation sections above).

Changes in Fair Value of Derivatives (millions)

Net fair value of derivatives as of Dec. 31, 2013	$9.7
Additions and net changes in unrealized fair value of derivatives	(35.2)
Changes in valuation techniques and assumptions	0.0
Realized net settlement of derivatives	(17.2)
Net fair value of derivatives as of Dec. 31, 2014	$(42.7)

Roll-Forward of Derivative Net Assets (Liabilities) (millions)

Total derivative net liabilities as of Dec. 31, 2013	$9.7
Change in fair value of net derivative assets:	
Recorded as regulatory assets and liabilities or other comprehensive income	(35.2)
Recorded in earnings	0.0
Realized net settlement of derivatives	(17.2)
Net fair value of derivatives as of Dec. 31, 2014	$(42.7)

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2014

(millions)	Current	Non-current	Total Fair Value
Source of fair value			
Actively quoted prices	$ 0.0	$ 0.0	$ 0.0
Other external price sources (1)	(36.6)	(6.1)	(42.7)
Model prices (2)	0.0	0.0	0.0
Total	$ (36.6)	$ (6.1)	$ (42.7)

(1) Reflects over-the-counter natural gas swaps for which the primary pricing inputs in determining fair value are NYMEX quoted closing prices of exchange-traded instruments.

(2) Model prices are used for determining the fair value of energy derivatives where price quotes are infrequent or the market is illiquid. Significant inputs to the models are derived from market-observable data and actual historical experience.

For all unrealized derivative contracts, the valuation is an estimate based on the best available information. Actual cash flows could be materially different from the estimated value upon maturity.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TECO ENERGY, INC.

Report of Independent Registered Certified Public Accounting Firm

To the Board of Directors and Shareholders of TECO Energy, Inc.:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control—Integrated Framework 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control over Financial Reporting, management has excluded New Mexico Gas Company and New Mexico Gas Intermediate from its assessment of internal control over financial reporting as of December 31, 2014 because they were acquired by the Company in a purchase business combination during 2014. We have also excluded New Mexico Gas Company and New Mexico Gas Intermediate from our audit of internal control over financial reporting. New Mexico Gas Company and New Mexico Gas Intermediate is a wholly-owned subsidiary whose total assets and total revenues represent 15% and 5%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida

February 27, 2015

TECO ENERGY, INC.

Consolidated Balance Sheets

Assets (millions)	Dec. 31, 2014	Dec. 31, 2013
Current assets		
Cash and cash equivalents	$25.4	$185.2
Receivables, less allowance for uncollectibles of $2.1 and $4.7 at Dec. 31, 2014 and 2013, respectively	299.8	287.2
Inventories, at average cost		
Fuel	96.4	118.7
Materials and supplies	75.4	85.9
Derivative assets	0.0	9.7
Regulatory assets	53.6	34.3
Deferred income taxes	72.8	100.3
Prepayments and other current assets	22.6	36.4
Assets held for sale	109.6	0.0
Total current assets	755.6	857.7
Property, plant and equipment		
Utility plant in service		
Electric	7,094.8	6,934.0
Gas	1,984.6	1,308.3
Construction work in progress	640.0	386.7
Other property	14.5	448.3
Property, plant and equipment, at original costs	9,733.9	9,077.3
Accumulated depreciation	(2,645.7)	(2,907.2)
Total property, plant and equipment, net	7,088.2	6,170.1
Other assets		
Regulatory assets	348.5	293.1
Goodwill	408.3	0.0
Derivative assets	0.0	0.3
Deferred charges and other assets	65.8	126.8
Assets held for sale	59.8	0.0
Total other assets	882.4	420.2
Total assets	$8,726.2	$7,448.0

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.

Consolidated Balance Sheets – continued

Liabilities and Capital (millions)	Dec. 31, 2014	Dec. 31, 2013
Current liabilities		
Long-term debt due within one year	$274.5	$83.3
Notes payable	139.0	84.0
Accounts payable	288.6	261.7
Customer deposits	176.2	164.5
Regulatory liabilities	57.0	85.8
Derivative liabilities	36.6	0.1
Interest accrued	39.9	31.9
Taxes accrued	29.9	34.6
Other	16.8	19.5
Liabilities associated with assets held for sale	39.4	0.0
Total current liabilities	1,097.9	765.4
Other liabilities		
Deferred income taxes	519.2	444.0
Investment tax credits	9.0	9.4
Regulatory liabilities	729.0	631.4
Derivative liabilities	6.1	0.2
Deferred credits and other liabilities	370.9	426.1
Liabilities associated with assets held for sale	65.4	0.0
Long-term debt, less amount due within one year	3,354.0	2,837.8
Total other liabilities	5,053.6	4,348.9
Commitments and Contingencies (see Note 12)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 234.9 million and 217.3 million shares outstanding at Dec. 31, 2014 and 2013, respectively)	234.9	217.3
Additional paid in capital	1,875.9	1,581.3
Retained earnings	479.6	548.3
Accumulated other comprehensive loss	(15.7)	(13.2)
Total TECO Energy capital	2,574.7	2,333.7
Total liabilities and capital	$8,726.2	$7,448.0

The accompanying notes are an integral part of the consolidated financial statements.

75

TECO ENERGY, INC.

Consolidated Statements of Income

(millions, except per share amounts)				
For the years ended Dec. 31,		2014	2013	2012
Revenues				
Regulated electric and gas		$2,557.3	$2,342.5	$2,377.4
Unregulated		9.1	12.6	10.3
Total revenues		2,566.4	2,355.1	2,387.7
Expenses				
Regulated operations and maintenance				
Fuel		692.3	680.2	694.7
Purchased power		71.4	64.7	105.3
Cost of natural gas sold		209.7	142.2	155.7
Other		547.8	524.4	462.5
Operation and maintenance other expense		29.5	12.5	7.9
Depreciation and amortization		315.3	291.8	289.6
Taxes, other than income		195.0	184.7	185.7
Total expenses		2,061.0	1,900.5	1,901.4
Income from operations		505.4	454.6	486.3
Other income (expense)				
Allowance for other funds used during construction		10.5	6.3	2.6
Other income		0.5	1.8	6.5
Loss on debt extinguishment		0.0	0.0	(1.2)
Total other income		11.0	8.1	7.9
Interest charges				
Interest expense		176.4	165.0	177.9
Allowance for borrowed funds used during construction		(5.3)	(3.6)	(1.5)
Total interest charges		171.1	161.4	176.4
Income from continuing operations before provision for income taxes		345.3	301.3	317.8
Provision for income taxes		138.9	112.6	120.8
Net income from continuing operations		206.4	188.7	197.0
Discontinued operations				
Income (loss) from discontinued operations		(125.4)	5.2	55.4
Provision (benefit) for income taxes		(49.4)	(3.8)	39.4
Income (loss) from discontinued operations, net		(76.0)	9.0	16.0
Less: Income from discontinued operations attributable to noncontrolling interest		0.0	0.0	0.3
Income (loss) from discontinued operations attributable to TECO Energy, net		(76.0)	9.0	15.7
Net income attributable to TECO Energy		$130.4	$197.7	$212.7
Average common shares outstanding	– Basic	223.1	215.0	214.3
	– Diluted	223.7	215.5	215.0
Earnings per share from continuing operations	– Basic	$0.92	$0.88	$0.92
	– Diluted	$0.92	$0.88	$0.92
	– Basic	$(0.34)	$0.04	$0.07

Earnings per share from discontinued operations attributable to TECO Energy				
	– Diluted	$(0.34)	$0.04	$0.07
Earnings per share attributable to TECO Energy	– Basic	$0.58	$0.92	$0.99
	– Diluted	$0.58	$0.92	$0.99
Dividends paid per common share outstanding		$0.88	$0.88	$0.88

Amounts shown include reclassifications to reflect discontinued operations as discussed in Note 19.

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.

Consolidated Statements of Comprehensive Income

(millions) For the years ended Dec. 31,	2014	2013	2012
Net income attributable to TECO Energy	$130.4	$197.7	$212.7
Other comprehensive income (loss), net of tax			
Net unrealized gains (losses) on cash flow hedges	0.7	1.4	(4.2)
Amortization of unrecognized benefit costs and other	(3.0)	14.8	(4.8)
Change in benefit obligation due to remeasurement	8.0	0.0	0.0
Increase in unrecognized postemployment costs	(8.2)	0.0	0.0
Recognized benefit costs due to settlement	0.0	1.6	0.0
Other comprehensive income (loss), net of tax	(2.5)	17.8	(9.0)
Comprehensive income	$127.9	$215.5	$203.7

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.

Consolidated Statements of Cash Flows

(millions)			
For the years ended Dec. 31,	2014	2013	2012
Cash flows from operating activities			
Net income attributable to TECO Energy	$130.4	$197.7	$212.7
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	341.9	329.5	337.7
Deferred income taxes and investment tax credits	89.4	110.1	136.6
Allowance for other funds used during construction	(10.5)	(6.3)	(2.6)
Non-cash stock compensation	12.7	13.5	12.0
(Gain) loss on sales of business/assets	(0.2)	(1.6)	18.5
Deferred recovery clauses	(15.2)	(6.2)	(8.9)
Asset impairment	115.9	0.0	17.2
Receivables, less allowance for uncollectibles	(36.6)	(4.5)	37.7
Inventories	12.8	1.1	(2.4)
Prepayments and other current assets	2.8	(2.2)	(2.0)
Taxes accrued	1.1	1.4	12.1
Interest accrued	7.3	(1.3)	(5.9)
Accounts payable	23.4	35.9	(1.3)
Other	(10.4)	(8.5)	(4.7)
Cash flows from operating activities	664.8	658.6	756.7
Cash flows from investing activities			
Capital expenditures	(714.3)	(532.4)	(505.1)
Allowance for other funds used during construction	10.5	6.3	2.6
Purchase of NMGI, net of cash acquired	(751.5)	0.0	0.0
Net proceeds from sales of business/assets	0.2	4.3	194.4
Restricted cash	0.0	0.0	8.9
Other investments	(7.9)	0.0	0.0
Cash flows used in investing activities	(1,463.0)	(521.8)	(299.2)
Cash flows from financing activities			
Dividends paid	(199.2)	(191.2)	(190.4)
Proceeds from the sale of common stock	302.3	6.7	3.9
Proceeds from long-term debt issuance	563.6	0.0	538.1
Repayment of long-term debt/Purchase in lieu of redemption	(83.3)	(51.6)	(650.4)
Change in short-term debt	55.0	84.0	0.0
Other financing activities	0.0	0.0	(2.2)
Cash flows from/(used in) financing activities	638.4	(152.1)	(301.0)
Net (decrease) increase in cash and cash equivalents	(159.8)	(15.3)	156.5
Cash and cash equivalents at beginning of the year	185.2	200.5	44.0
Cash and cash equivalents at end of the year	$25.4	$185.2	$200.5
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest	$161.3	$161.0	$188.4
Income taxes paid	$2.9	$1.8	$7.2
Supplemental disclosure of non-cash activities			
Debt assumed in NMGI acquisition	$200.0	$0.0	$0.0

Change in accrued capital expenditures	$13.3	$4.7	$(13.9)

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.

Consolidated Statements of Capital

(millions)	Shares	Common Stock	Additional Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Capital
Balance, Dec. 31, 2011	215.8	$ 215.8	$ 1,553.4	$ 519.4	$ (22.0)	$ 0.6	$ 2,267.2
Net income				212.7		0.3	213.0
Other comprehensive loss, after tax					(9.0)		(9.0)
Common stock issued	0.8	0.8	(3.7)				(2.9)
Cash dividends declared				(190.4)			(190.4)
Stock compensation expense			12.0				12.0
Noncontrolling—dividends						(0.3)	(0.3)
Tax benefits—stock compensation			2.8				2.8
Noncontrolling—sale of business						(0.6)	(0.6)
Balance, Dec. 31, 2012	216.6	$ 216.6	$ 1,564.5	$ 541.7	$ (31.0)	$ 0.0	$ 2,291.8
Net income				197.7			197.7
Other comprehensive income, after tax					17.8		17.8
Common stock issued	0.7	0.7	5.2				5.9
Cash dividends declared				(191.2)			(191.2)
Stock compensation expense			13.5				13.5
Restricted stock—dividends			1.0	0.1			1.1
Tax short fall—stock compensation			(2.9)				(2.9)
Balance, Dec. 31, 2013	217.3	$ 217.3	$ 1,581.3	$ 548.3	$ (13.2)	$ 0.0	$ 2,333.7
Net income				130.4			130.4
Other comprehensive loss, after tax					(2.5)		(2.5)
Common stock issued	17.6	17.6	283.2				300.8
Cash dividends declared				(199.2)			(199.2)
Stock compensation expense			12.7				12.7
Restricted stock—dividends			1.1	0.1			1.2
Tax short fall—stock compensation			(2.4)				(2.4)
Balance, Dec. 31, 2014	234.9	$ 234.9	$ 1,875.9	$ 479.6	$ (15.7)	$ 0.0	$ 2,574.7

The accompanying notes are an integral part of the consolidated financial statements.

TECO ENERGY, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

Description of the Business

TECO Energy is a holding company for regulated utilities and other businesses. TECO Energy currently owns no operating assets but holds all of the common stock of TEC and, through its subsidiaries, NMGI and TECO Diversified, owns NMGC and TECO Coal, respectively.

TEC, a Florida corporation and TECO Energy’s largest subsidiary, has two business segments. Its Tampa Electric division provides retail electric services in West Central Florida, and PGS, the gas division of TEC, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida.

NMGC, a Delaware corporation and wholly owned subsidiary of NMGI, was acquired by the company on Sept. 2, 2014. NMGC is engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in New Mexico.

TECO Coal, a Kentucky LLC, has 10 subsidiaries located in Eastern Kentucky, Tennessee and Virginia. These entities own mineral rights, own or operate surface and underground mines and own interests in coal processing and loading facilities. On Oct. 17, 2014, TECO Diversified entered into an agreement to sell all of its ownership interest in TECO Coal. On Feb. 5, 2015, the agreement was amended to extend the closing date to Mar. 13, 2015.

The significant accounting policies for both utility and diversified operations are as follows:

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of TECO Energy and its majority-owned subsidiaries. Intercompany balances and intercompany transactions have been eliminated in consolidation.

The consolidated financial statements include NMGI and NMGC as of the acquisition date of Sept. 2, 2014 (see Note 21). In addition, all periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for TECO Coal and certain charges at TECO Energy that are directly related to TECO Coal (see Note 19).

For entities that are determined to meet the definition of a VIE, the company obtains information, where possible, to determine if it is the primary beneficiary of the VIE. If the company is determined to be the primary beneficiary, then the VIE is consolidated and a minority interest is recognized for any other third-party interests. If the company is not the primary beneficiary, then the VIE is accounted for using the equity or cost method of accounting. In certain circumstances this can result in the company consolidating entities in which it has less than a 50% equity investment and deconsolidating entities in which it has a majority equity interest (see Note 18).

Use of Estimates

The use of estimates is inherent in the preparation of financial statements in accordance with GAAP. Actual results could differ from these estimates.

Cash Equivalents

Cash equivalents are highly liquid, high-quality investments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

Planned Major Maintenance

Tampa Electric, PGS and NMGC expense major maintenance costs as incurred. For electric and gas utilities, concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with the regulations of FERC, FPSC and NMPRC, as applicable.

Planned major maintenance projects at TECO Coal that do not increase the overall life or value of the related assets are expensed as incurred. When the major maintenance materially increases the life or value of the underlying asset, the cost is capitalized. While normal maintenance outages covering various components of the plants generally occur on at least a yearly basis, major overhauls occur less frequently.

Depreciation

Tampa Electric, PGS and NMGC compute depreciation and amortization for electric generation, electric transmission and distribution, gas distribution and general plant facilities using the following methods:

- the group remaining life method, approved by the FPSC or NMPRC, is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property;
- the amortizable life method, approved by the FPSC or NMPRC, is applied to the net book value to date over the remaining life of those assets not classified as depreciable property above.

The provision for total regulated utility plant in service (including NMGC from the acquisition date), expressed as a percentage of the original cost of depreciable property, was 3.6% for 2014, 3.7% for 2013 and 3.8% for 2012.

On Sept. 11, 2013, the FPSC unanimously voted to approve a stipulation and settlement agreement between TEC and all of the intervenors in its Tampa Electric division base rate proceeding. As a result, Tampa Electric began using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013.

Other TECO Energy subsidiaries compute depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage value, of depreciable property over the following estimated useful lives:

Asset	Estimated Useful Lives
Building and improvements	5 - 40 years
Office equipment and furniture	3 - 30 years
Vehicles and other equipment	2 - 15 years
Computer software	2 - 15 years

Total depreciation expense for the years ended Dec. 31, 2014, 2013 and 2012 was $307.5 million, $285.6 million and $276.3 million, respectively.

Allowance for Funds Used During Construction

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The FPSC approved rate used to calculate Tampa Electric's AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. Tampa Electric's rate was 8.16% for May 2009 through December 2013. In March 2014, the rate was revised to 6.46% effective Jan. 1, 2014. NMGC's rate used to calculate its AFUDC in 2014 was 4.92%. Total AFUDC for the years ended Dec. 31, 2014, 2013 and 2012 was $15.8 million, $9.9 million and $4.1 million, respectively.

Inventory

TEC and NMGC value materials, supplies and fossil fuel inventory (coal, oil or natural gas) using a weighted-average cost method. These materials, supplies and fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered with a normal profit upon sale in the ordinary course of business. TECO Coal inventories are stated at the lower of cost, computed on the first-in, first-out method, or net realizable value. Parts and supplies inventories are stated at the lower of cost or market on an average cost basis. TECO Coal's inventory is classified within Assets held for sale at Dec. 31, 2014.

Fuel Inventory (millions)	Dec. 31, 2014	Dec. 31, 2013
Tampa Electric	$85.2	$ 93.7
TECO Coal	0.0	25.0
NMGC	11.2	0.0
Total	$96.4	$ 118.7

Regulatory Assets and Liabilities

Tampa Electric, PGS and NMGC are subject to accounting guidance for the effects of certain types of regulation (see Note 3 for additional details).

Deferred Income Taxes

TECO Energy uses the asset and liability method to determine deferred income taxes. Under the asset and liability method, the company estimates its current tax exposure and assesses the temporary differences resulting from differences in the treatment of items, such as depreciation, for financial statement and tax purposes. These differences are reported as deferred taxes, measured at current rates, in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not that some or all of the deferred tax assets will not be realized. If management determines that it is likely that some or all of deferred tax assets will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized (see Note 4 for additional details).

Investment Tax Credits

ITCs have been recorded as deferred credits and are being amortized as reductions to income tax expense over the service lives of the related property.

Goodwill

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated fair values of assets acquired and liabilities assumed at the acquisition date. Under the accounting guidance for goodwill, goodwill is subject to an annual assessment for impairment at the reporting unit level. See Note 20 for further detail.

Employee Postretirement Benefits

The company sponsors a defined benefit retirement plan and other postretirement benefits. The measurement of the plans are based on several statistical and other factors, including those that attempt to anticipate future events. See Note 5 for further detail.

Revenue Recognition

TECO Energy recognizes revenues consistent with accounting standards for revenue recognition. Except as discussed below, TECO Energy and its subsidiaries recognize revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer.

The regulated utilities' retail businesses and the prices charged to customers are regulated by the FPSC or NMPRC, as applicable. Tampa Electric's wholesale business is regulated by the FERC. See Note 3 for a discussion of significant regulatory matters and the applicability of the accounting guidance for certain types of regulation to the company.

Revenues for TECO Coal shipments, both domestic and international, are recognized when title and risk of loss transfer to the customer. They are included in "Income (loss) from discontinued operations" on the Consolidated Statements of Income.

Revenues for energy marketing operations at TECO EnergySource, Inc. are presented on a net basis in accordance with the accounting guidance for reporting revenue gross as a principal versus net as an agent and recognition and reporting of gains and losses on energy trading contracts to reflect the nature of the contractual relationships with customers and suppliers. Accordingly, for the years ended Dec. 31, 2014, 2013 and 2012, total costs of $4.3 million, $23.1 million and $13.8 million, respectively, consisting primarily of natural gas purchased, were netted against revenues in the "Revenues-Unregulated" caption on the Consolidated Statements of Income.

Shipping and Handling

TECO Coal incurred costs to ship product to customers of $5.2 million, $8.2 million and $9.0 million for the years ended Dec. 31, 2014, 2013 and 2012, respectively. The costs are included in “Income (loss) from discontinued operations” on the Consolidated Statements of Income.

Cash Flows Related to Derivatives and Hedging Activities

The company classifies cash inflows and outflows related to derivative and hedging instruments in the appropriate cash flow sections associated with the item being hedged. In the case of diesel fuel swaps, which are used to mitigate the fluctuations in the price of diesel fuel, the cash inflows and outflows are included in the operating section. For natural gas and ongoing interest rate swaps, the cash inflows and outflows are included in the operating section. For interest rate swaps that settle coincident with the debt issuance, the cash inflows and outflows are treated as premiums or discounts and included in the financing section of the Consolidated Statements of Cash Flows.

Revenues and Cost Recovery

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, gas storage, interstate pipeline capacity and conservation costs for PGS and NMGC. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over- or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as regulatory liabilities, and under-recoveries of costs are recorded as regulatory assets.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. The regulated utilities accrue base revenues for services rendered but unbilled to provide for a closer matching of revenues and expenses (see Note 3). As of Dec. 31, 2014 and 2013, unbilled revenues of $86.6 million and $46.7 million, respectively, are included in the "Receivables" line item on TECO Energy's Consolidated Balance Sheets.

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. Tampa Electric purchased power from non-TECO Energy affiliates at a cost of $71.4 million, $64.7 million and $105.3 million, for the years ended Dec. 31, 2014, 2013 and 2012, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost recovery clause.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

TECO Coal incurs most of TECO Energy's total excise taxes, which are accrued as an expense and reconciled to the actual cash payment of excise taxes. As general expenses, they are not specifically recovered through revenues. Excise taxes paid by the regulated utilities are not material and are expensed when incurred.

Tampa Electric and PGS are allowed to recover certain costs on a dollar-per-dollar basis incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. Franchise fees and gross receipt taxes payable by Tampa Electric and PGS are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". These amounts totaled $113.9 million, $108.5 million and $111.5 million for the years ended Dec. 31, 2014, 2013 and 2012, respectively. NMGC is an agent in the collection and payment of franchise fees and gross receipt taxes, and they are not required by a tariff to present the amounts on a gross basis. Therefore, NMGC's franchise fees and gross receipt taxes are presented net with no line item impact on the Consolidated Statement of Income.

Deferred Charges and Other Assets

Deferred charges and other assets consist primarily of offering costs associated with various debt offerings that are being amortized over the related obligation period as an increase in interest expense, as well as mining development costs amortized on a per ton basis in 2013 and assets related to NMGC's ROW in 2014. The mining development costs were impaired in 2014. See Notes 20 and 21 for additional information on the impairment and ROW, respectively.

Debt issuance costs – The company capitalizes the external costs of obtaining debt financing and includes them in "Deferred charges and other assets" on TECO Energy's Consolidated Balance Sheet and amortizes such costs over the life of the related debt on a straight-line basis that approximates the effective interest method. These amounts are reflected in "Interest expense" on TECO Energy's Consolidated Statements of Income.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued postretirement and pension liabilities, and medical and general liability claims incurred but not reported. The company and its subsidiaries have a self-insurance program supplemented by excess insurance coverage for the cost of claims whose ultimate value exceeds the company's retention amounts. The company estimates its liabilities for auto, general and workers' compensation using discount rates mandated by statute or otherwise deemed appropriate for the circumstances. Discount rates used in estimating these other self-insurance liabilities at Dec. 31, 2014 and 2013 ranged from 2.71% to 3.86% and 3.51% to 4.86%, respectively.

Stock-Based Compensation

TECO Energy accounts for its stock-based compensation in accordance with the accounting guidance for share-based payment. Under the provisions of this guidance, share-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period (generally the vesting period of the equity grant). See Note 9 for more information on share-based payments.

Receivables and Allowance for Uncollectible Accounts

Receivables consist of services billed to residential, commercial, industrial and other customers. An allowance for uncollectible accounts is established based on the regulated utilities' collection experience. Circumstances that could affect Tampa Electric's, PGS's and NMGC's estimates of uncollectible receivables include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible. TECO Coal's receivables consist of coal sales billed to industrial and utility customers. An allowance for uncollectible accounts is established based on TECO Coal's collection experience. Circumstances that could affect TECO Coal's estimates of uncollectable receivables include customer credit issues and general economic conditions. Accounts are written off once they are determined to be uncollectible.

2. New Accounting Pronouncements

Extraordinary and Unusual Items

In January 2015, the FASB issued guidance to remove the concept of extraordinary items from U.S. GAAP. Therefore, events or transactions that are of an unusual nature and occur infrequently will no longer be allowed to be separately disclosed, net of tax, in the income statement after income from continuing operations. The standard is effective for the company beginning Jan. 1, 2016. The company does not expect a significant impact from the adoption of this guidance.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

In April 2014, the FASB issued guidance regarding changing the criteria for reporting discontinued operations. Under this new guidance, which is intended to enhance convergence of the FASB's and the IASB's reporting requirements for discontinued operations, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results. This standard is effective prospectively for the company beginning in 2015.

Revenue from Contracts with Customers

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The standard is principle-based and provides a five-step model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This guidance is effective for the company beginning in 2017 and allows for either full retrospective adoption or modified retrospective adoption. The company is currently evaluating the impact of the adoption of this guidance on its financial statements but does not expect the impact to be significant.

Going Concern

In August 2014, the FASB issued guidance defining management's responsibility to decide whether there is substantial doubt about an organization's ability to continue as a going concern and the related footnote disclosures required. This guidance is effective prospectively for the company beginning in 2017. The company does not expect any significant impact from the adoption of this guidance on its financial statements.

3. Regulatory

Tampa Electric's retail business and PGS are regulated by the FPSC. Tampa Electric is also subject to regulation by the FERC under PUHCA 2005. The operations of PGS are regulated by the FPSC separately from the operations of Tampa Electric. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC sets rates at a level that allows utilities such as Tampa Electric and PGS to collect total revenues (revenue requirements) equal to their cost of providing service, plus a reasonable return on invested capital.

NMGC is subject to regulation by the NMPRC. The NMPRC has jurisdiction over the regulatory matters related, directly and indirectly, to NMGC providing service to its customers, including, among other things, rates, accounting procedures, securities issuances, and standards of service. NMGC must follow certain accounting guidance that pertains specifically to entities that are subject to such regulation. Comparable to the FPSC, the NMPRC sets rates at a level that allows utilities such as NMGC to collect total revenues (revenue requirement) equal to their cost of providing service, plus a reasonable return on invested capital.

Base Rates-Tampa Electric

Tampa Electric's results for the first ten months of 2013 and all of 2012 reflect base rates established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE midpoint of 11.25%, 54.0% equity in the capital structure and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for CTs and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

Tampa Electric's results for 2014 and the last two months of 2013 reflect the results of a Stipulation and Settlement Agreement entered on Sept. 6, 2013, between TEC and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric's 2013 base rate proceeding. On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement.

This agreement provided for the following revenue increases: $57.5 million effective Nov. 1, 2013, an additional $7.5 million effective Nov. 1, 2014, an additional $5.0 million effective Nov. 1, 2015, and an additional $110.0 million effective Jan. 1, 2017 or the date that the expansion of TEC's Polk Power Station goes into service, whichever is later. The agreement provides that Tampa Electric's allowed regulatory ROE would be a mid-point of 10.25% with a range of plus or minus 1%, with a potential increase to 10.50% if U.S. Treasury bond yields exceed a specified threshold. The agreement provides that Tampa Electric cannot file for additional rate increases until 2017 (to be effective no sooner than Jan. 1, 2018), unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE is increased as described above) any party to the agreement other than TEC could seek a review of Tampa Electric's base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital and Tampa Electric began using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013. Effective Nov. 1, 2013, Tampa Electric ceased accruing $8.0 million annually to the FERC-authorized and FPSC-approved self-insured storm damage reserve.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services and accounting practices.

Tampa Electric Storm Damage Cost Recovery

Prior to the above mentioned stipulation and settlement agreement, Tampa Electric was accruing $8.0 million annually to a FERC-authorized and FPSC-approved self-insured storm damage reserve. This reserve was created after Florida's IOUs were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Effective Nov. 1, 2013, Tampa Electric ceased accruing for this storm damage reserve as a result of the 2013 rate case settlement. However, in the event of a named storm that results in damage to its system, Tampa Electric can petition the FPSC to seek recovery of those costs over a 12-month period or longer as determined by the FPSC, as well as replenish its reserve to $56.1 million; the level it was as of Oct. 31, 2013. Tampa Electric's storm reserve remained $56.1 million at both Dec. 31, 2014 and 2013.

Base Rates-PGS

PGS's base rates were established in May 2009 and reflect an ROE of 10.75%, which is the middle of a range between 9.75% to 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital, on an allowed rate base of $560.8 million.

Base Rates-NMGC

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC's base rates by approximately $34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on Jan. 31, 2012, revising, among other things, base rates for all service provided on or after Feb. 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC’s base rate revenue by approximately $21.5 million on a normalized annual basis. The monthly residential customer access fee increased from $9.59 to $11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017 as reported in Note 21.

Regulatory Assets and Liabilities

Tampa Electric, PGS and NMGC apply the accounting standards for regulated operations. Areas of applicability include: deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost-recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs; and the deferral of costs as regulatory assets to the period in which the regulatory agency recognizes them, when cost recovery is ordered over a period longer than a fiscal year.

Details of the regulatory assets and liabilities as of Dec. 31, 2014 and 2013 are presented in the following table:

(millions)	Dec. 31, 2014	Dec. 31, 2013
Regulatory assets:		
Regulatory tax asset (1)	$69.2	$67.4
Other:		
Cost-recovery clauses	45.1	6.1
Postretirement benefit asset (2)	194.0	182.7
Deferred bond refinancing costs (3)	7.2	8.0
Debt basis adjustment (3)	20.9	0.0
Environmental remediation	53.1	51.4
Competitive rate adjustment	2.8	4.1
Other	9.8	7.7
Total other regulatory assets	332.9	260.0
Total regulatory assets	402.1	327.4
Less: Current portion	53.6	34.3
Long-term regulatory assets	$348.5	$293.1
Regulatory liabilities:		
Regulatory tax liability (1)	$6.9	$9.8
Other:		
Cost-recovery clauses	25.9	54.5
Transmission and delivery storm reserve	56.1	56.1
Deferred gain on property sales (4)	0.8	2.0
Accumulated reserve—cost of removal	695.2	594.0
Other	1.1	0.8
Total other regulatory liabilities	779.1	707.4
Total regulatory liabilities	786.0	717.2
Less: Current portion	57.0	85.8
Long-term regulatory liabilities	$729.0	$631.4

(1) Primarily related to plant life and derivative positions.
(2) Amortized over the remaining service life of plan participants.
(3) Amortized over the term of the related debt instruments.
(4) Amortized over a 5-year period with various ending dates.

All regulatory assets are recovered through the regulatory process. The following table further details the regulatory assets and the related recovery periods:

Regulatory assets

(millions)	Dec. 31, 2014	Dec. 31, 2013
Clause recoverable (1)	$47.9	$10.2
Components of rate base (2)	199.0	185.6
Regulatory tax assets (3)	69.2	67.4
Capital structure and other (3)	86.0	64.2
Total	$402.1	$327.4

(1) To be recovered through cost-recovery mechanisms approved by the FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in the next year.

(2) Primarily reflects allowed working capital, which is included in rate base and earns a rate of return as permitted by the FPSC.

(3) "Regulatory tax assets" and "Capital structure and other" regulatory assets, including environmental remediation, have a recoverable period longer than a fiscal year and are recognized over the period authorized by the regulatory agency. Also included are unamortized loan costs, which are amortized over the life of the related debt instruments. See footnotes 1 and 2 in the prior table for additional information.

4. Income Taxes

Income Tax Expense

In 2014, 2013 and 2012, TECO Energy recorded net tax provisions from continuing operations of $138.9 million, $112.6 million and $120.8 million, respectively. A majority of this provision is non-cash. TECO Energy has net operating losses that are being utilized to reduce its taxable income. As such, cash taxes paid for income taxes as required for the alternative minimum tax, state income taxes, foreign income taxes and prior year audits in 2014, 2013 and 2012 were $2.9 million, $1.8 million and $7.2 million, respectively.

Income tax expense consists of the following:

Income Tax Expense (Benefit)

(millions) For the year ended Dec. 31,	2014	2013	2012
Continuing Operations			
Current income taxes			
Federal	$0.5	$2.2	$15.7
State	0.0	0.0	0.0
Deferred income taxes			
Federal	111.0	98.8	89.2
State	27.7	11.9	16.2
Amortization of investment tax credits	(0.3)	(0.3)	(0.3)
Income tax expense from continuing operations	138.9	112.6	120.8

Discontinued Operations			
Current income taxes			
Federal	0.0	0.0	0.0
Foreign	0.0	0.0	6.8
State	(0.4)	(3.5)	1.1
Deferred income taxes			
Federal	(44.0)	(0.3)	28.6
Foreign	0.0	0.0	0.0
State	(5.0)	0.0	2.9
Income tax expense from discontinued operations	(49.4)	(3.8)	39.4
Total income tax expense	$89.5	$108.8	$160.2

During 2014 and 2013, TECO Energy increased its net operating loss carryforward. Total current income tax expense for the year ended Dec. 31, 2012 was reduced by $13.6 million to reflect the benefits of operating loss carryforwards.

The reconciliation of the federal statutory rate to the company's effective income tax rate is as follows:

Effective Income Tax Rate

(millions)			
For the year ended Dec. 31,	2014	2013	2012
Income tax expense at the federal statutory rate of 35%	$120.9	$105.5	$111.2
Increase (decrease) due to:			
State income tax, net of federal income tax	17.0	7.5	10.4
Valuation allowance	0.9	0.0	1.1
Other	0.1	(0.4)	(1.9)
Total income tax expense from continuing operations	$138.9	$112.6	$120.8
Income tax expense as a percent of income from continuing operations, before income taxes	40.2 %	37.4 %	38.0 %

For the three years presented, the overall effective tax rate on continuing operations was higher than the 35% U.S. federal statutory rate primarily due to state income taxes. For 2014, the effective tax rate also increased by 1.9% as a result of a state consolidated tax adjustment.

As discussed in Note 1, TECO Energy uses the asset and liability method to determine deferred income taxes. Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2014 will be realized in future periods.

Deferred Income Taxes

The major components of the company's deferred tax assets and liabilities recognized are as follows:

(millions)		
As of Dec. 31,	2014	2013
Deferred tax liabilities (1)		
Property related	$1,391.3	$1,164.2
Pension	62.3	52.8
Total deferred tax liabilities	1,453.6	1,217.0
Deferred tax assets (1)		
Alternative minimum tax credit carryforward	214.0	213.0
Loss and credit carryforwards (2)	566.7	479.8
Other postretirement benefits	71.5	68.9
Other	159.6	111.6
Total deferred tax assets	1,011.8	873.3
Valuation allowance (3)	(4.6)	0.0
Total deferred tax assets, net of valuation allowance	1,007.2	873.3
Total deferred tax liability, net	446.4	343.7
Less: Current portion of deferred tax asset	(72.8)	(100.3)
Long-term portion of deferred tax liability, net	$519.2	$444.0

(1) Certain property related assets and liabilities have been netted.

(2)

As a result of certain realization requirements of accounting guidance, loss carryforwards do not include certain deferred tax assets as of Dec. 31, 2014 that arose directly from tax deductions related to equity compensation greater than compensation recognized for financial reporting. Stockholder's equity will be increased by $1.1 million when such deferred tax assets are ultimately realized. The company uses tax law ordering when determining when excess tax benefits have been realized.

(3) $3.6 million related to discontinued operations.

At Dec. 31, 2014, the company had cumulative unused federal, Florida, New Mexico and Kentucky NOLs for income tax purposes of $1,543.7 million, $562.4 million, $56.0 million, and $18.4 million, respectively, expiring at various times between 2025 and 2033. The federal NOL includes $110.4 million of acquired NOLs due to the acquisition of NMGI. In addition, the company has unused general business credits of $4.0 million expiring between 2026 and 2033. During 2014, the company's available AMT credit carryforward increased from $213.0 million to $214.0 million. The AMT credit may be used indefinitely to reduce federal income taxes.

The company's consolidated balance sheet reflects loss carryforwards excluding amounts resulting from excess stock-based compensation. Accordingly, such losses from excess stock-based compensation tax deductions are accounted for as an increase to additional paid-in capital if and when realized through a reduction in income taxes payable.

The company establishes valuation allowances on its deferred tax assets, including losses and tax credits, when the amount of expected future taxable income is not likely to support the use of the deduction or credit. During 2014, the company recorded a $4.6 million valuation allowance for state NOL carryforwards and state deferred tax assets, net of federal tax. The valuation allowance includes $3.6 million related to TECO Coal discontinued operations.

Unrecognized Tax Benefits

The company accounts for uncertain tax positions in accordance with FASB guidance. This guidance addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under the guidance, the company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The guidance also provides standards on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions)	2014	2013	2012
Balance at Jan. 1,	$0.0	$2.9	$4.1
Decreases due to expiration of statute of limitations	0.0	(2.9)	0.0
Dispositions	0.0	0.0	(1.2)
Balance at Dec. 31	$0.0	$0.0	2.9

The company recognizes interest and penalties associated with uncertain tax positions in "Operation other expense – Other" in the Consolidated Statements of Income. In 2014, 2013 and 2012, the company recognized $0.0 million, $(0.9) million and $0.3 million, respectively, of pretax charges (benefits) for interest only. Additionally, the company had $0.0 million of interest accrued at Dec. 31, 2014 and 2013. No amounts have been recorded for penalties.

The company's U.S. subsidiaries join in the filing of a U.S. federal consolidated income tax return. The IRS concluded its examination of the company's 2013 consolidated federal income tax return in January 2015. The U.S. federal statute of limitations remains open for the year 2011 and forward. Years 2014 and 2015 are currently under examination by the IRS under its Compliance Assurance Program. U.S. state and foreign jurisdictions have statutes of limitations generally ranging from three to four years from the filing of an income tax return. Additionally, any state net operating losses that were generated in prior years and are still being utilized are subject to examination by state jurisdictions. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by taxing authorities in major state jurisdictions and foreign jurisdictions include 2005 and forward. The company does not expect the settlement of audit examinations to significantly change the total amount of unrecognized tax benefits within the next 12 months.

5. Employee Postretirement Benefits

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on employees’ age, years of service and final average earnings.

The Pension Protection Act became effective Jan. 1, 2008 and requires companies to, among other things, maintain certain defined minimum funding thresholds (or face plan benefit restrictions), pay higher premiums to the PBGC if they sponsor defined benefit plans, amend plan documents and provide additional plan disclosures in regulatory filings and to plan participants.

WRERA was signed into law on Dec. 23, 2008. WRERA grants plan sponsors relief from certain funding requirements and benefits restrictions, and also provides some technical corrections to the Pension Protection Act. There are two primary provisions that impact funding results for TECO Energy. First, for plans funded less than 100%, required shortfall contributions were based on a percentage of the funding target until 2013, rather than the funding target of 100%. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging subject to certain limitations in the determination of funding requirements. TECO Energy utilizes asset smoothing in determining funding requirements.

In August 2014, the President signed into law HAFTA, which modified MAP-21. HAFTA and MAP-21 provide funding relief for pension plan sponsors by stabilizing discount rates used in calculating the required minimum pension contributions and increasing PBGC premium rates to be paid by plan sponsors. The company expects the required minimum pension contributions to be lower than the levels previously projected; however, the company plans on funding at levels above the required minimum pension contributions under HAFTA and MAP-21.

The qualified pension plan's actuarial value of assets, including credit balance, was 110.8% of the Pension Protection Act funded target as of Jan. 1, 2014 and is estimated at 115.9% of the Pension Protection Act funded target as of Jan. 1, 2015.

Amounts disclosed for pension benefits in the following tables and discussion also include the unfunded obligations for the SERP. This is a non-qualified, non-contributory defined benefit retirement plan available to certain members of senior management. TECO Coal participants will cease earning pension benefits upon the anticipated sale. As a result, a curtailment loss was recognized in the fourth quarter of 2014. See curtailment-related line items in tables below.

A curtailment loss in the Retirement Plan was recognized in the fourth quarter of 2014 in anticipation of the sale of TECO Coal. See curtailment-related line items in tables below.

Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits (Other Benefits or Other Postretirement Benefit Plan) for most employees retiring after age 50 meeting certain service requirements. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

MMA added prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan are at least "actuarially equivalent" to the standard drug benefits that are offered under Medicare Part D.

The FASB issued accounting guidance and disclosure requirements related to MMA. The guidance requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

In March 2010, the Patient Protection and Affordable Care Act and a companion bill, the Health Care and Education Reconciliation Act, collectively referred to as the Health Care Reform Acts, were signed into law. Among other things, both acts reduce the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, TECO Energy reduced its deferred tax asset in 2010 and recorded a true up in 2013. TEC is amortizing the regulatory asset over the remaining average service life of 12 years. Additionally, the Health Care Reform Acts contain other provisions that may impact TECO Energy's obligation for retiree medical benefits. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase its PBO. TECO Energy will continue to monitor and assess the impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

Effective Jan. 1, 2013, the company decided to implement an EGWP for its post-65 retiree prescription drug plan. The EGWP is a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduces net periodic benefit cost by taking advantage of rebate and discount enhancements provided under the Health Care Reform Acts, which are greater than the subsidy payments previously received by the company under Medicare Part D for its post-65 retiree prescription drug plan.

NMGC has a separate, partially-funded other postretirement benefit plan. It is not presented separately; rather, it is presented with TECO Energy’s plan in the tables and discussion below. Since NMGC is allowed to recover its other postretirement benefit costs through rates, the regulated asset established prior to the acquisition for pre-acquisition-related prior service cost, actuarial loss, and transition obligation was maintained after the acquisition. This regulated asset will be amortized. See “unrecognized costs in regulated asset acquired in business combination” line item in the Funded status table below.

Effective Jan. 1, 2015, the TECO Coal participants were terminated from the Other Postretirement Benefit Plan. As a result, the other postretirement benefit obligation for TECO Coal was eliminated as of Dec. 31, 2014. See curtailment-related line items in tables below.

Obligations and Funded Status

TECO Energy recognizes in its statement of financial position the over-funded or under-funded status of its postretirement benefit plans. This status is measured as the difference between the fair value of plan assets and the PBO in the case of its defined benefit plan, or the APBO in the case of its other postretirement benefit plan. Changes in the funded status are reflected, net of estimated tax benefits, in the benefit liabilities and AOCI in the case of the unregulated companies, or the benefit liabilities and regulatory assets in the case of TEC and NMGC. The results of operations are not impacted. Below is the detail of the change in benefit obligations, change in plan assets, unfunded liability and amounts recognized in the Consolidated Balance Sheets for 2014 and 2013.

Obligations and Funded Status	Pension Benefits		Other Benefits	
(millions)	2014	2013	2014	2013
Change in benefit obligation				
Net benefit obligation at beginning of year	$666.0	$715.0	$208.1	$230.3
Service cost	18.3	18.2	2.5	2.5
Interest cost	32.0	28.9	10.8	9.3
Plan participants' contributions	0.0	0.0	2.8	2.9
Plan amendments	0.0	0.0	(23.2)	0.0
Actuarial loss (gain)	48.3	(50.4)	1.5	(22.1)
Gross benefits paid	(39.9)	(43.1)	(16.0)	(15.0)
Transfer in due to the effect of business combination	0.0	0.0	26.7	0.0
Plan curtailment	4.0	0.0	(11.7)	0.0
Special termination benefit	0.2	0.0	0.0	0.0
Settlements	0.0	(2.6)	0.0	0.0
Federal subsidy on benefits paid	n/a	n/a	0.0	0.2
Net benefit obligation at end of year	$728.9	$666.0	$201.5	$208.1

Change in plan assets				
Fair value of plan assets at beginning of year	$593.0	$529.1	$0.0	$0.0
Actual return on plan assets	46.4	63.7	0.1	0.0
Employer contributions	47.5	44.6	(1.0)	11.9
Employer direct benefit payments	1.0	1.3	16.0	
Plan participants' contributions	0.0	0.0	2.8	2.9
Transfer in due to acquisition	0.0	0.0	16.9	0.0
Settlements	0.0	(2.6)	0.0	0.0
Net benefits paid	(39.9)	(43.1)	(16.0)	(14.8)
Fair value of plan assets at end of year	$648.0	$593.0	$18.8	$0.0

Funded status				
Fair value of plan assets [(1)]	$648.0	$593.0	$18.8	$0.0
Less: Benefit obligation (PBO/APBO)	728.9	666.0	201.5	208.1
Funded status at end of year	(80.9)	(73.0)	(182.7)	(208.1)
Unrecognized costs in regulated asset acquired in business combination	0.0	0.0	6.4	0.0
Unrecognized net actuarial loss	203.7	173.1	9.6	19.7
Unrecognized prior service (benefit) cost	0.0	(0.4)	(24.0)	(0.7)
Net amount required to be recognized at end of year	$122.8	$99.7	$(190.7)	$(189.1)

Amounts recognized in balance sheet				
Regulatory assets	$167.4	$139.6	$26.6	$43.2
Accrued benefit costs and other current liabilities	(4.9)	(3.3)	(10.7)	(13.3)
Deferred credits and other liabilities	(76.0)	(69.7)	(172.0)	(194.8)
Accumulated other comprehensive loss (income), pretax	36.3	33.1	(34.6)	(24.2)
Net amount recognized at end of year	$122.8	$99.7	$(190.7)	$(189.1)

(1) The MRV of plan assets is used as the basis for calculating the EROA component of periodic pension expense. MRV reflects the fair value of plan assets adjusted for experience gains and losses (i.e. the differences between actual investment returns and expected returns) spread over five years.

91

Amounts recognized in accumulated other comprehensive income, pretax

	Pension Benefits		Other Benefits	
(millions)	2014	2013	2014	2013
Net actuarial loss (gain)	$36.0	$32.7	$(30.1)	$(23.8)
Prior service cost (credit)	0.3	0.4	(4.5)	(0.4)
Amount recognized, pretax	$36.3	$33.1	$(34.6)	$(24.2)

The accumulated benefit obligation for all defined benefit pension plans was $685.0 million at Dec. 31, 2014 and $624.1 million at Dec. 31, 2013. The projected benefit obligation for the other postretirement benefits plan was $201.5 million at Dec. 31, 2014 and $208.1 million at Dec. 31, 2013.

Assumptions used to determine benefit obligations at Dec. 31:

	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
Discount rate	4.258%	5.118%	4.211%	5.096%
Rate of compensation increase—weighted	3.87%	3.73%	3.86%	3.71%
Healthcare cost trend rate				
Immediate rate	n/a	n/a	7.09%	7.25%
Ultimate rate	n/a	n/a	4.57%	4.50%
Year rate reaches ultimate	n/a	n/a	2025	2025

A one-percentage-point change in assumed health care cost trend rates would have the following effect on the benefit obligation:

(millions)	1% Increase	1% Decrease
Effect on postretirement benefit obligation	$ 7.0	$ (6.4)

The discount rate assumption used to determine the Dec. 31, 2014 benefit obligation was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

Amounts recognized in Net Periodic Benefit Cost, OCI, and Regulatory Assets

(millions)	Pension Benefits			Other Benefits		
	2014	2013	2012	2014	2013	2012
Service cost	$18.3	$18.2	$17.0	$2.5	$2.5	$2.4
Interest cost	32.0	28.9	30.1	10.8	9.3	10.1
Expected return on plan assets	(41.8)	(38.4)	(37.1)	(0.3)	0.0	0.0
Amortization of:						
Actuarial loss	13.5	20.5	15.3	0.2	1.0	0.1
Prior service (benefit) cost	(0.4)	(0.4)	(0.4)	(0.2)	(0.4)	0.8
Transition obligation	0.0	0.0	0.0	0.0	0.0	1.8
Curtailment loss (gain)	3.9	0.0	0.0	(0.2)	0.0	0.0
Special termination benefit	0.2	0.0	0.0	0.0	0.0	0.0
Settlement loss	0.0	1.0	0.0	0.0	0.0	0.0
Net periodic benefit cost	$25.7	$29.8	$24.9	$12.8	$12.4	$15.2
Prior service cost	$0.0	$0.0	$0.0	$(23.6)	$0.0	$(5.2)
Net loss (gain)	44.1	(75.7)	34.0	(9.9)	(15.6)	16.3
Unrecognized costs in regulated asset acquired in business combination	0.0	0.0	0.0	6.4	0.0	0.0
Amortization of:						
Actuarial gain (loss)	(13.5)	(21.5)	(15.3)	(0.2)	(1.0)	(0.1)
Prior service (benefit) cost	0.4	0.4	0.4	0.2	0.3	(0.8)
Transition obligation	0.0	0.0	0.0	0.0	0.0	(1.8)
Total recognized in OCI and regulatory assets	$31.0	$(96.8)	$19.1	$(27.1)	$(16.3)	$8.4
Total recognized in net periodic benefit cost, OCI and regulatory assets	$56.7	$(67.0)	$44.0	$(14.3)	$(3.9)	$23.6

A curtailment loss and special termination benefits were recognized for the Retirement Plan due to the expected sale of TECO Coal. Additionally, a curtailment gain was recognized for the OPEB plan due to the termination of the TECO Coal plan effective Jan. 1, 2015.

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $3.3 million and $0.3 million, respectively. The estimated prior service cost for the other postretirement benefit plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year is $0.5 million.

In addition, the estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year are $10.0 million and $0.1 million, respectively. There will be no net loss and an estimated $1.9 million prior service credit that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year for the other postretirement benefit plan. Additionally, $1.1 million of NMGC's pre-acquisition regulated asset will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31:

	Pension Benefits			Other Benefits		
	2014 (a)	2013	2012	2014	2013	2012
Discount rate	5.118%/4.[illegible]%/4.3[illegible]%	[illegible]	[illegible] %	5.096%	4.180%	4.744%
Expected long-term return on plan assets	7.25%/7.00%/7.00%	7.50	7.50 %	5.75	n/a	n/a
Rate of compensation increase	3.73%	3.76 %	3.83 %	3.71 %	3.74 %	3.82 %
Healthcare cost trend rate						
Initial rate	n/a	n/a	n/a	7.25 %	7.50 %	7.75 %
Ultimate rate	n/a	n/a	n/a	4.50 %	4.50 %	4.50 %
Year rate reaches ultimate	n/a	n/a	n/a	2025	2025	2025

(a)TECO Energy performed a valuation as of Jan. 1, 2014. TECO remeasured its Retirement Plan on Sept. 2, 2014 for the acquisition of NMGC and on Oct. 31, 2014 for the expected curtailment of TECO Coal, resulting in the respective updated discount rates and EROAs.

The discount rate assumption used to determine the 2014 benefit cost was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

The expected return on assets assumption was based on historical returns, fixed income spreads and equity premiums consistent with the portfolio and asset allocation at the measurement date. A change in asset allocations could have a significant impact on the expected return on assets. Additionally, expectations of long-term inflation, real growth in the economy and a provision for active management and expenses paid were incorporated in the assumption. For the year ended Dec. 31, 2014, TECO Energy's pension plan experienced actual asset returns of approximately 7.9%.

The compensation increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases.

A one-percentage-point change in assumed health care cost trend rates would have the following effect on expense:

(millions)	1% Increase	1% Decrease
Effect on periodic cost	$ 0.4	$ (0.4)

Pension Plan Assets

Pension plan assets (plan assets) are primarily invested in a mix of equity and fixed income securities. The company's investment objective is to obtain above-average returns while minimizing volatility of expected returns and funding requirements over the long term. The company's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

	Target Allocation	Actual Allocation, End of Year

Asset Category		2014	2013
Equity securities	48%-54%	50%	54%
Fixed income securities	46%-52%	50%	46%
Total	100%	100%	100%

The company reviews the plan’s asset allocation periodically and re-balances the investment mix to maximize asset returns, optimize the matching of investment yields with the plan’s expected benefit obligations, and minimize pension cost and funding. The company will continue to monitor the matching of plan assets with plan liabilities.

The plan’s investments are held by a trust fund administered by JP Morgan Chase Bank, N.A. (JP Morgan). JP Morgan measures fair value using the procedures set forth below for all investments. When available, JP Morgan uses quoted market prices on investments traded on an exchange to determine fair value and classifies such items as Level 1. In some cases where a market exchange price is available, but the investments are traded in a secondary market, JP Morgan makes use of acceptable practical expedients to calculate fair value, and the company classifies these items as Level 2.

If observable transactions and other market data are not available, fair value is based upon third-party developed models that use, when available, current market-based or independently-sourced market parameters such as interest rates, currency rates or option volatilities. Items valued using third-party generated models are classified according to the lowest level input or value driver that is most significant to the valuation. Thus, an item may be classified in Level 3 even though there may be significant inputs that are readily observable.

As required by the fair value accounting standards, the investments are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The plan's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For cash equivalents, the cost approach was used in determining fair value. For bonds and U.S. government agencies, the income approach was used. For other investments, the market approach was used. The following table sets forth by level within the fair value hierarchy the plan's investments as of Dec. 31, 2014 and Dec. 31, 2013.

(millions)	At Fair Value as of Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash	$0.4	$0.0	$ 0.0	$0.4
Accounts receivable	1.4	0.0	0.0	1.4
Accounts payable	(5.3)	0.0	0.0	(5.3)
Cash equivalents				
Short term investment funds (STIFs)	7.6	0.0	0.0	7.6
Treasury bills (T bills)	0.0	0.2	0.0	0.2
Discounted notes	0.0	8.8	0.0	8.8
Total cash equivalents	7.6	9.0	0.0	16.6
Equity securities				
Common stocks	98.0	0.0	0.0	98.0
American depository receipts (ADRs)	1.3	0.0	0.0	1.3
Real estate investment trusts (REITs)	2.5	0.0	0.0	2.5
Preferred stock	0.8	0.0	0.0	0.8
Mutual funds	171.3	0.0	0.0	171.3
Commingled fund	0.0	45.6	0.0	45.6
Total equity securities	273.9	45.6	0.0	319.5
Fixed income securities				
Municipal bonds	0.0	6.1	0.0	6.1
Government bonds	0.0	47.9	0.0	47.9
Corporate bonds	0.0	22.0	0.0	22.0
Asset backed securities (ABS)	0.0	0.3	0.0	0.3
Mortgage-backed securities (MBS), net short sales	0.0	9.6	0.0	9.6
Collateralized mortgage obligations (CMOs)	0.0	2.0	0.0	2.0
Mutual fund	0.0	98.6	0.0	98.6
Commingled fund	0.0	129.2	0.0	129.2
Total fixed income securities	0.0	315.7	0.0	315.7
Derivatives				
Short futures	0.0	(0.3)	0.0	(0.3)
Purchased options (swaptions)	0.0	0.7	0.0	0.7
Written options (swaptions)	0.0	(0.8)	0.0	(0.8)
Total derivatives	0.0	(0.4)	0.0	(0.4)
Miscellaneous	0.0	0.1	0.0	0.1

Total	$278.0	$370.0	$ 0.0	$648.0

95

(millions)	At Fair Value as of Dec. 31, 2013			
	Level 1	Level 2	Level 3	Total
Accounts receivable	$44.7	$0.0	$ 0.0	$44.7
Accounts payable	(40.8)	0.0	0.0	(40.8)
Cash equivalents				
Short term investment funds (STIFs)	7.9	0.0	0.0	7.9
Treasury bills (T bills)	0.0	0.3	0.0	0.3
Repurchase agreement	0.0	8.8	0.0	8.8
Commercial paper	0.0	0.4	0.0	0.4
Money markets	0.0	1.5	0.0	1.5
Total cash equivalents	7.9	11.0	0.0	18.9
Equity securities				
Common stocks	91.6	0.0	0.0	91.6
American depository receipts (ADRs)	3.0	0.0	0.0	3.0
Real estate investment trusts (REITs)	1.7	0.0	0.0	1.7
Preferred stock	0.0	0.8	0.0	0.8
Mutual funds	172.6	0.0	0.0	172.6
Commingled fund	0.0	50.0	0.0	50.0
Total equity securities	268.9	50.8	0.0	319.7
Fixed income securities				
Municipal bonds	0.0	7.3	0.0	7.3
Government bonds	0.0	35.7	0.0	35.7
Corporate bonds	0.0	19.6	0.0	19.6
Asset backed securities (ABS)	0.0	0.4	0.0	0.4
Mortgage-backed securities (MBS), net short sales	0.0	6.7	0.0	6.7
Collateralized mortgage obligations (CMOs)	0.0	2.3	0.0	2.3
Mutual fund	0.0	85.1	0.0	85.1
Commingled fund	0.0	94.1	0.0	94.1
Total fixed income securities	0.0	251.2	0.0	251.2
Derivatives				
Short futures	0.0	0.2	0.0	0.2
Swaps	0.0	(0.9)	0.0	(0.9)
Purchased options (swaptions)	0.0	0.2	0.0	0.2
Written options (swaptions)	0.0	(0.4)	0.0	(0.4)
Total derivatives	0.0	(0.9)	0.0	(0.9)
Miscellaneous	0.0	0.2	0.0	0.2
Total	$280.7	$312.3	$ 0.0	$593.0

The primary pricing inputs in determining the fair value of the Level 1 assets, excluding the mutual funds and STIF, are closing quoted prices in active markets.

The STIF is valued at net asset value (NAV) as determined by JP Morgan. Shares may be redeemed any business day at the NAV calculated after the order is accepted. The NAV is validated with purchases and sales at NAV, making this a Level 1 asset.

The primary pricing inputs in determining the Level 1 mutual funds are the mutual funds' NAVs. The funds are registered open-ended mutual funds and the NAVs are validated with purchases and sales at NAV, making these Level 1 assets.

The repurchase agreements and money markets are valued at cost due to their short term nature. Additionally, repurchase agreements are backed by collateral.

T bills and commercial paper are valued using benchmark yields, reported trades, broker dealer quotes, and benchmark securities.

The primary pricing inputs in determining the fair value of the preferred stock is the price of underlying and common stock of the same issuer, average life, and benchmark yields.

The methodology and inputs used to value the investment in the equity commingled fund are broker dealer quotes. The fund holds primarily international equity securities that are actively traded in OTC markets. The fund honors subscription and redemption activity on an “as of” basis.

The primary pricing inputs in determining the fair value Level 2 municipal bonds are benchmark yields, historical spreads, sector curves, rating updates, and prepayment schedules. The primary pricing inputs in determining the fair value of government bonds are the U.S. Treasury curve, CPI, and broker quotes, if available. The primary pricing inputs in determining the fair value of corporate bonds are the U.S. treasury curve, base spreads, YTM, and benchmark quotes. ABS and CMOs are priced using TBA prices, treasury curves, swap curves, cash flow information, and bids and offers as inputs. MBS are priced using TBA prices, treasury curves, average lives, spreads, and cash flow information. Commercial MBS are priced using payment information and yields.

The primary pricing input in determining the fair value of the Level 2 mutual fund is its NAV. However, since this mutual fund is an unregistered open-ended mutual fund, it is a Level 2 asset.

The fixed income commingled fund is a private fund valued at NAV as determined by a third party at year end. The fund invests in long duration U.S. investment-grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The NAV is calculated based on bid prices of the underlying securities. The fund honors subscription activity on the first business day of the month and the first business day following the 15th calendar day of the month. Redemptions are honored on the 15th or last business day of the month, providing written notice is given at least ten business days prior to withdrawal date.

Futures are valued using futures data, cash rate data, swap rates, and cash flow analyses.

Swaps are valued using benchmark yields, swap curves, and cash flow analyses.

Options are valued using the bid-ask spread and the last price.

Other Postretirement Benefit Plan Assets

NMGC’s other postretirement benefits plan had $18.8 million of assets as of Dec. 31, 2014. The majority of the assets are valued at the cash surrender value of NMGC participant life insurance policies and are considered Level 2 assets. In accordance with NMPRC requirements, NMGC must fund to a trust, on an annual basis, an amount equal to the other postretirement expense allowed in its last base rate case.

Contributions

The company’s policy is to fund the qualified pension plan at or above amounts determined by its actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. The company made $47.5 million and $42.0 million of contributions to this plan in 2014 and 2013, respectively, which met the minimum funding requirements for both 2014 and 2013. These amounts are reflected in the “Other” line on the Consolidated Statements of Cash Flows. The company estimates its contribution in 2015 to be $43.7 million and expects to make contributions from 2016 to 2019 in the range of $2.5 to $36.5 million per year based on current assumptions. These contributions are in excess of the minimum required contribution under ERISA guidelines.

The SERP is funded periodically to meet the benefit obligations. The company made contributions of $1.2 million and $2.6 million to this plan in 2014 and 2013, respectively. In 2015, the company expects to make contributions of about $4.9 million to this plan.

The company funds its other postretirement benefits periodically to meet benefit obligations. The company’s contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and Jun. 30, 2001 is limited to a defined dollar benefit based on service. The company’s contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after July 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. In 2015, the company expects to make contributions of about $14.3 million. This includes $3.6 million that NMGC is required to fund to its trust in accordance with NMPRC requirements. Postretirement benefit levels are substantially unrelated to salary.

Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Expected Benefit Payments

(including projected service and net of employee contributions)

(millions)	Pension Benefits	Other Postretirement Benefits
2015	$ 73.4	$ 11.5
2016	47.9	12.0
2017	47.8	12.5
2018	51.9	12.9
2019	58.3	13.4
2020-2024	285.5	69.5

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. The company and its subsidiaries match up to 6% of the participant's payroll savings deductions. Effective April 2013, employer matching contributions were 65% of eligible participant contributions with additional incentive match of up to 35% of eligible participant contributions based on the achievement of certain operating company financial goals. Prior to this, the employer matching contributions were 60% of eligible participant contributions, with an additional incentive match of up to 40%. For the years ended Dec. 31, 2014, 2013 and 2012, the company and its subsidiaries recognized expense totaling $13.1 million, $11.3 million and $7.0 million, respectively, related to the matching contributions made to this plan.

Effective Jan. 1, 2015, the employer matching contribution will increase to 70% of eligible participant contributions with additional incentive match of up to 30%.

Black Lung Liability

TECO Coal is required by federal and state statutes to provide benefits to terminated, retired or (under state statutes) qualifying active employees for benefits related to black lung disease. TECO Coal is self-insured for black lung related claims. TECO Coal applied the accounting guidance of ASC 715, Compensation – Retirement Benefits, and annual expense was recorded for black lung obligations as determined by an independent actuary at the present value of the actuarially-computed liability for such benefits over the employee's applicable term of service. At Dec. 31, 2014 and 2013, TECO Coal had an actuarially-determined black lung liability of $24.7 million and $24.5 million, respectively. TECO Coal recognized expense related to the black lung liability of $2.4 million, $2.2 million and $1.8 million for 2014, 2013 and 2012, respectively.

As discussed in Note 19, TECO Coal was classified as an asset held for sale in 2014. In accordance with ASC 715, an after-tax settlement charge of $7.9 million related to the unfunded black lung obligations recorded in accumulated other comprehensive income will be recognized as a loss from discontinued operations upon completion of the sale of TECO Coal, which is expected to occur in 2015.

98

6. Short-Term Debt

At Dec. 31, 2014 and Dec. 31, 2013, the following credit facilities and related borrowings existed:

Credit Facilities

(millions)	Dec. 31, 2014 Credit Facilities	Borrowings Outstanding[1]	Letters of Credit Outstanding	Dec. 31, 2013 Credit Facilities	Borrowings Outstanding[1]	Letters of Credit Outstanding
Tampa Electric Company:						
5-year facility [2]	$325.0	$ 12.0	$ 0.6	$325.0	$ 6.0	$ 0.7
1-year accounts receivable facility	150.0	46.0	0.0	150.0	78.0	0.0
TECO Energy/TECO Finance:						
5-year facility [2][3]	300.0	50.0	0.0	200.0	0.0	0.0
New Mexico Gas Company:						
5-year facility [2]	125.0	31.0	1.7	0.0	0.0	0.0
Total	$900.0	$ 139.0	$ 2.3	$675.0	$ 84.0	$ 0.7

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

At Dec. 31, 2014, these credit facilities required commitment fees ranging from 12.5 to 30.0 basis points. The weighted-average interest rate on borrowings outstanding under the credit facilities at Dec. 31, 2014 and 2013 was 1.16% and 0.56%, respectively.

Tampa Electric Company Accounts Receivable Facility

On Feb. 3, 2015, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 13 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A., Inc. as Program Agent. The amendment extends the maturity date to Apr. 14, 2015.

TECO Energy Credit Agreement Assigned to and Assumed by NMGC

On Dec. 17, 2013, TECO Energy entered into a $125 million bank credit facility, pursuant to which it was the initial party to the Credit Agreement (the NMGC Credit Agreement). TECO Energy had no rights or obligations to borrow under the NMGC Credit Agreement, which was entered into solely with the intent of it being assigned to, and assumed by, NMGC upon the closing of the Acquisition. Pursuant to the terms of the NMGC Credit Agreement, on Sept. 2, 2014, TECO Energy designated NMGC as the borrower under the NMGC Credit Agreement by delivering a Joinder and Release Agreement duly executed by TECO Energy and NMGC, whereupon (i) NMGC became the borrower for all purposes of the NMGC Credit Agreement and the other credit facility documents under the NMGC Credit Agreement, and (ii) TECO Energy ceased to be a party to the NMGC Credit Agreement and any further rights or obligations thereunder. The NMGC Credit Agreement (i) has a maturity date of Dec. 17, 2018 (subject to further extension with the consent of each lender); (ii) allows NMGC to borrow funds at a rate equal to the one-month London interbank deposit rate plus a margin; (iii) as an alternative to the above interest rate, allows NMGC to borrow funds at an interest rate equal to a margin plus the higher of JPMorgan Chase Bank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (iv) allows NMGC to borrow funds on a same-day basis under a swingline loan provision, which loans mature on the fourth Banking Day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (v) allows NMGC to request the lenders to increase their commitments under the credit facility by up to $75 million in the aggregate; and (vi) includes a $40 million letter of credit facility.

On Sept. 30, 2014, NMGC entered into an amendment of its $125 million bank credit facility, which reallocated commitments among the lenders and made certain other technical changes.

TECO Energy and TECO Finance Bridge Facility

TECO Energy and TECO Finance entered into a $1.075 billion senior unsecured bridge credit agreement (the Bridge Facility) on June 24, 2013, among TECO Energy as guarantor, TECO Finance as borrower, Morgan Stanley Senior Funding, Inc. (Morgan Stanley) as administrative agent, sole lead arranger and sole book runner, and Morgan Stanley together with nine other banks as lenders in the Bridge Facility. TECO Energy unconditionally guaranteed TECO Finance’s obligations under the Bridge Facility. In the third quarter of 2014, TECO Energy permanently financed the NMGC Acquisition with a combination of (i) a TECO Energy equity offering, (ii) the issuance of debt at NMGC and NMGI, (iii) cash on hand and (iv) short-term borrowings. Upon closing of the acquisition on Sept. 2, 2014, the commitment under the Bridge Facility was permanently cancelled by TECO Energy and TECO Finance.

Amendment of Tampa Electric Company Credit Facility

On Dec. 17, 2013, TEC amended and restated its $325 million bank credit facility, entering into a Fourth Amended and Restated Credit Agreement. The amendment (i) extended the maturity date of the credit facility from Oct. 25, 2016 to Dec. 17, 2018 (subject to further extension with the consent of each lender); (ii) continued to allow TEC to borrow funds at a rate equal to the London interbank deposit rate plus a margin; (iii) as an alternative to the above interest rate, allows TEC to borrow funds at an interest rate equal to a margin plus the higher of Citibank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (iv) allows TEC to borrow funds on a same-day basis under a swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (v) continues to allow TEC to request the lenders to increase their commitments under the credit facility by up to $175 million in the aggregate; (vi) includes a $200 million letter of credit facility; and (vii) made other technical changes.

On Sept. 30, 2014, TEC entered into an amendment of its $325 million bank credit facility, which reallocated commitments among the lenders and made certain other technical changes.

Amendments of TECO Energy/TECO Finance Credit Facility

On Dec. 17, 2013, TECO Energy amended and restated its $200 million bank credit facility, entering into a Fourth Amended and Restated Credit Agreement (the TECO Credit Facility). The amendment (i) extended the maturity date of the credit facility from Oct. 25, 2016 to Dec. 17, 2018 (subject to further extension with the consent of each lender); (ii) continues with TECO Energy as Guarantor and its wholly-owned subsidiary, TECO Finance, as Borrower; (iii) allows TECO Finance to borrow funds at an interest rate equal to the London interbank deposit rate plus a margin; (iv) as an alternative to the above interest rate, allows TECO Finance to borrow funds at an interest rate equal to a margin plus the higher of the JPMorgan Chase Bank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (v) allows TECO Finance to borrow funds on a same-day basis under a swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (vi) allows TECO Finance to request the lenders to increase their commitments under the credit facility by $100 million in the aggregate; (vii) continues to include a $200 million letter of credit facility; and (viii) made other technical changes.

The Fourth Amended and Restated Credit Agreement includes the changes made in Amendment No. 1 dated June 24, 2013 (Amendment) to the TECO Energy/TECO Finance Third Amended and Restated Credit Agreement dated Oct. 25, 2011. Amendment No. 1 was entered into to accommodate the acquisition of NMGI, as described in Note 21 herein, by (i) temporarily changing the total debt to total capitalization financial covenant such that, during the four fiscal quarters commencing with the quarter in which the acquisition closed, TECO Energy must maintain a total debt to total capitalization ratio of no greater than 0.70 to 1.00, instead of the previous capitalization ratio of 0.65 to 1.00 and (ii) changed the definition of Permitted Liens to permit the acquisition of a significant subsidiary that has outstanding secured debt and made other changes matching the corresponding covenant in the Bridge Facility, as described in Note 21.

On Sept. 30, 2014, the TECO Credit Facility was amended to increase total commitments to $300 million and to reallocate commitments among the lenders.

7. Long-Term Debt

At Dec. 31, 2014, total long-term debt had a carrying amount of $3,628.5 million and an estimated fair market value of $3,987.8 million. At Dec. 31, 2013, total long-term debt had a carrying amount of $2,921.1 million and an estimated fair market value of $3,184.1 million. The company uses the market approach in determining fair value. The majority of the outstanding debt is valued using real-time financial market data obtained from Bloomberg Professional Service. The remaining securities are valued using prices obtained from the Municipal Securities Rulemaking Board and by applying estimated credit spreads obtained from a third party to the par value of the security. All debt securities are Level 2 instruments.

TECO Finance is a 100% owned subsidiary of TECO Energy. TECO Finance's sole purpose is to raise capital for TECO Energy's diversified businesses. TECO Energy is a full and unconditional guarantor of TECO Finance's securities, and no other subsidiaries of TECO Energy guarantee TECO Finance's securities.

A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.

TECO Energy's gross maturities and annual sinking fund requirements of long-term debt for 2015 through 2019 and thereafter are as follows:

Long-Term Debt Maturities

As of Dec. 31, 2014 (millions)	2015	2016	2017	2018	2019	Thereafter	Total Long-Term Debt
TECO Finance	$191.2	$250.0	$300.0	$0.0	$0.0	$ 300.0	$ 1,041.2
Tampa Electric	83.3	83.4	0.0	254.2	0.0	1,436.7	1,857.6
PGS	0.0	0.0	0.0	50.0	0.0	191.7	241.7
NMGI	0.0	0.0	0.0	0.0	50.0	150.0	200.0
NMGC	0.0	0.0	0.0	0.0	0.0	270.0	270.0
Total long-term debt maturities	$274.5	$333.4	$300.0	$304.2	$50.0	$ 2,348.4	$ 3,610.5

Issuance of Tampa Electric Company 4.35% Notes due 2044

On May 15, 2014, TEC completed an offering of $300 million aggregate principal amount of 4.35% Notes due 2044 (the TEC 2014 Notes). The TEC 2014 Notes were sold at 99.933% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, estimated offering expenses and before settlement of interest rate swaps) of approximately $296.6 million. Net proceeds were used to repay short-term debt and for general corporate purposes. TEC may redeem all or any part of the TEC 2014 Notes at its option at any time and from time to time before Nov. 15, 2043 at a redemption price equal to the greater of (i) 100% of the principal amount of TEC 2014 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the notes to be redeemed, discounted at an applicable treasury rate (as defined in the indenture), plus 15 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Nov. 15, 2043, TEC may at its option redeem the TEC 2014 Notes, in whole or in part, at 100% of the principal amount of the notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

Issuance of New Mexico Gas Intermediate Senior Unsecured Notes

On Sept. 2, 2014, NMGI completed an offering of $50 million aggregate principal amount of 2.71% Series A Senior Unsecured Notes due July 30, 2019 (the NMGI Series A 2014 Notes) and $150 million aggregate principal amount of 3.64% Series B Senior Unsecured Notes due July 30, 2024 (the NMGI Series B 2014 Notes and, with the NMGI Series A 2014 Notes, the NMGI 2014 Notes). The NMGI 2014 Notes were sold at 100% of par. The offering resulted in net proceeds to NMGI (after deducting underwriting discounts, commissions and estimated offering expenses) of approximately $198.4 million. Net proceeds were used to repay existing indebtedness and for general corporate purposes. NMGI may redeem all or any part of the NMGI 2014 Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of NMGI 2014 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the NMGI notes to be redeemed, discounted at an applicable reinvestment yield (as defined in the note purchase agreement), plus 50 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. The NMGI 2014 Notes were issued in a private placement that was not subject to the registration requirements of the Securities Act of 1933.

Issuance of New Mexico Gas Company Senior Unsecured 3.54 % Notes due 2026

On Sept. 2, 2014, NMGC completed an offering of $70 million aggregate principal amount of 3.54% Senior Unsecured Notes due July 30, 2026 (the NMGC 2014 Notes). The NMGC 2014 Notes were sold at 100% of par. The offering resulted in net proceeds to NMGC (after deducting underwriting discounts, commissions and estimated offering expenses) of approximately $69.3 million. Net proceeds were used to repay existing indebtedness and for general corporate purposes. NMGC may redeem all or any part of the NMGC 2014 Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of NMGC 2014 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the notes to be redeemed, discounted at an applicable reinvestment yield (as defined in the note purchase agreement), plus 50 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. The NMGC 2014 Notes were issued in a private placement that was exempt from the registration requirements of the Securities Act of 1933.

Amendment of New Mexico Gas Company 4.87 % Notes due 2021

On Feb. 8, 2011, NMGC issued secured notes in an aggregate principal amount of $200 million (NMGC 2011 Notes), maturing Feb. 8, 2021. The NMGC 2011 Notes were issued in a private placement that was exempt from the registration requirements of the Securities Act of 1933.

On July 16, 2014, NMGC received approvals from the noteholders of the NMGC 2011 Notes to release the collateral securing the NMGC 2011 Notes by amending the existing note purchase agreement. The amendments to the note purchase agreement were subject to the approval of the NMPRC and on Oct. 22, 2014, NMGC received the required NMPRC approval of the amendments. On Oct. 30, 2014, the amendments became effective and the collateral securing the NMGC 2011 Notes was released and other technical changes were made to the NMGC 2011 Notes.

Purchase in Lieu of Redemption of Revenue Refunding Bonds, Series 2007 B

On Mar. 15, 2012, TEC purchased in lieu of redemption $86.0 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (Non-AMT) (the Series 2006 HCIDA Bonds). On Mar. 19, 2008, the HCIDA had remarketed the Series 2006 HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2006 HCIDA Bonds bore interest at a term rate of 5.00% per annum from Mar. 19, 2008 to Mar. 15, 2012. TEC is responsible for payment of the interest and principal associated with the Series 2006 HCIDA Bonds. Regularly scheduled principal and interest when due, are insured by Ambac Assurance Corporation.

On Sept. 3, 2013, TEC purchased in lieu of redemption $51.6 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 B (the Series 2007 B HCIDA Bonds). On Mar. 26, 2008, the HCIDA had remarketed the Series 2007 B HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2007 B HCIDA Bonds bore interest at a term rate of 5.15% per annum from Mar. 26, 2008 to Sept. 1, 2013. TEC is responsible for payment of the interest and principal associated with the Series 2007 B HCIDA Bonds.

As of Dec. 31, 2014, $232.6 million of bonds purchased in lieu of redemption were held by the trustee at the direction of TEC to provide an opportunity to evaluate refinancing alternatives.

At Dec. 31, 2014 and 2013, TECO Energy had the following long-term debt outstanding:

Long-Term Debt (millions)		Due	2014	2013
TECO Finance	Notes (1)(2)(3) : 6.75%	2015	$191.2	$191.2
	4.00%	2016	250.0	250.0
	6.57%	2017	300.0	300.0
	5.15%	2020	300.0	300.0
	Total long-term debt of TECO Finance		1,041.2	1,041.2
Tampa Electric	Installment contracts payable (4) :			
	5.65% Refunding bonds	2018	54.2	54.2
	Variable rate bonds repurchased in 2008 (5)	2020	0.0	0.0
	5.15% Refunding bonds repurchased in 2013 (6)	2025	0.0	0.0
	1.5% Term rate bonds repurchased in 2011 (7)	2030	0.0	0.0
	5.0% Refunding bonds repurchased in 2012 (8)	2034	0.0	0.0
	Notes (1)(2) : 6.25%	2014-2016	166.7	250.0
	6.10%	2018	200.0	200.0
	5.40%	2021	231.7	231.7
	2.60%	2022	225.0	225.0
	6.55%	2036	250.0	250.0
	6.15%	2037	190.0	190.0
	4.10%	2042	250.0	250.0
	4.35%	2044	290.0	0.0
	Total long-term debt of Tampa Electric		1,857.6	1,650.9
PGS	Notes (1)(2) : 6.10%	2018	50.0	50.0
	5.40%	2021	46.7	46.7
	2.60%	2022	25.0	25.0
	6.15%	2037	60.0	60.0
	4.10%	2042	50.0	50.0
	4.35%	2044	10.0	0.0
	Total long-term debt of PGS		241.7	231.7
NMGI	Notes (1)(2) : 2.71%	2019	50.0	0.0
	3.64%	2024	150.0	0.0
	Total long-term debt of NMGI		200.0	0.0
NMGC	Notes (1)(2) : 4.87%	2021	200.0	0.0
	3.54%	2026	70.0	0.0
	Total long-term debt of NMGC		270.0	0.0
	Total long-term debt of TECO Energy		3,610.5	2,923.8
Unamortized debt discount, net			18.0	(2.7)
Total carrying amount of long-term debt			3,628.5	2,921.1
Less amount due within one year			274.5	83.3
Total long-term debt			$3,354.0	$2,837.8

(1) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(2) These long-term debt agreements contain various restrictive financial covenants.
(3) Guaranteed by TECO Energy.
(4) Tax-exempt securities.
(5) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by TEC. These held variable rate bonds have a par amount of $20.0 million due in 2020.
(6)

In September 2013 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $51.6 million due in 2025.

(7) In March 2011 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $75.0 million due in 2030.

103

(8) In March 2012 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $86.0 million due in 2034.

8. Preferred Stock

Preferred stock of TECO Energy – $1 par

10 million shares authorized, none outstanding.

Preference stock (subordinated preferred stock) of Tampa Electric – no par

2.5 million shares authorized, none outstanding.

Preferred stock of Tampa Electric – no par

2.5 million shares authorized, none outstanding.

Preferred stock of Tampa Electric – $100 par

1.5 million shares authorized, none outstanding.

9. Common Stock

Public Offering of 15.5 million in Common Shares

On July 1, 2014, the company entered into an underwriting agreement with Morgan Stanley & Co. LLC, as representative of the several underwriters named therein, pursuant to which the company agreed to offer and sell 15.5 million shares of its common stock in an underwritten public offering at a public offering price of $18.10 per share. The company received approximately $271 million in net proceeds from the offering after underwriting fees and offering expenses. The shares were delivered to the underwriters on July 8, 2014.

Pursuant to the terms of the underwriting agreement, the company granted the underwriters a 30-day option to purchase up to an additional 2.3 million shares. The company received approximately $21 million of net proceeds when the underwriters exercised this option for an additional 1.2 million shares.

The company used the net proceeds from the offering to fund, in part, the acquisition of NMGI and for general corporate purposes.

Stock-Based Compensation

On May 5, 2010, the shareholders approved the 2010 Equity Incentive Plan (2010 Plan) as an amendment and restatement of both the company’s 2004 Equity Incentive Plan (2004 Plan) and the 1997 Director Equity Plan (1997 Plan, and together with the 2004 Plan, the Old Plans). The 2010 Plan superseded the Old Plans and no additional grants will be made under the Old Plans. The rights of the holders of outstanding options, unvested restricted stock or other outstanding awards under the Old Plans were not affected. The purpose of the 2010 Plan is to attract and retain key employees and non-employee directors, to enable the company to provide equity-based incentives relating to achieving long-range performance goals and to enable award recipients to participate in the long-term growth of the company. The 2010 Plan is administered by the Compensation Committee of the Board of Directors (Committee), which may grant awards to any employee of the company who is capable of contributing significantly to the successful performance of the company. Only the Board of Directors may grant awards to any non-employee members of the Board of Directors.

The 2010 Plan amended the 2004 Plan to reduce the number of shares of common stock subject to grants to 4.0 million shares (a reduction of 3.0 million shares), remove the cap on shares available for stock grant, place various limitations on the terms of awards granted under the 2010 Plan, remove the ability to make awards to consultants of the company and reapprove the business criteria upon which objective performance goals may be established by the Committee to continue to permit the company to take federal tax deductions for performance-based awards made to certain senior officers under Section 162(m) of the tax code.

The types of awards that can be granted under the 2010 Plan include stock options, stock grants and stock equivalents. Stock options were last awarded in 2006 under the Old Plans. Stock grants and time-vested restricted stock are valued at the fair market value on the date of grant, with expense recognized over the vesting period, which is normally three years. Time-vested restricted stock granted to directors vest in one year. Performance-based restricted stock has been granted to officers and employees, with shares potentially vesting after three years. The total awards for performance-based restricted stock vest based on the total return of TECO Energy common stock compared to a peer group of utility stocks. The performance-based grants can vest between 0% and 150% of the original grant. Dividends are paid on all time-vested stock grants during the vesting period. Dividends are accrued during the vesting period on all performance stock granted and paid at vesting date on the shares that vest. The value of time-vested restricted stock and stock grants are based on the fair market value of TECO Energy common stock at the time of grant.

The fair market value of stock options is determined using the Black-Scholes valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of options granted is based on accounting guidance for the simplified method of averaging the vesting term and the original contractual term; the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the option); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant.

The fair market value of performance-based restricted stock awards is determined using the Monte-Carlo valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of the awards is based on the performance measurement period (which is generally three years); the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the award); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant, with continuous compounding.

Assumptions	2014	2013	2012
Assumptions applicable to performance-based restricted stock			
Risk-free interest rate	0.68 %	0.41 %	0.38 %
Expected lives (in years)	3	3	3
Expected stock volatility	17.36 %	19.04 %	20.99 %
Dividend yield	5.13 %	4.83 %	4.78 %

In 2014, 2013 and 2012, 0.8 million, 0.7 million and 1.0 million shares of restricted stock were granted, respectively, with weighted-average fair value per share of $14.69, $17.21 and $15.96, respectively. The total fair market value of awards vesting during 2014, 2013 and 2012 was $3.6 million, $3.5 million and $14.3 million, respectively, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2014, there was $12.7 million of unrecognized compensation cost related to all non-vested awards that is expected to be recognized over a weighted-average period of two years.

The following table provides additional information on compensation costs and income tax benefits and excess tax benefits related to the stock-based compensation awards.

(millions)	2014	2013	2012
Compensation costs (1)	$12.7	$13.5	$12.0
Income tax benefits (1)	4.9	5.2	4.6
Excess tax benefits (2)	0.4	0.0	2.6

(1) Reflected on the Consolidated Statements of Income.
(2) Reflected as financing activities on the Consolidated Statements of Cash Flows.

The aggregate intrinsic value of stock options exercised was $2.7 million, $2.4 million and $0.3 million for the periods ended Dec. 31, 2014, 2013 and 2012, respectively. Cash received from option exercises under all share-based payment arrangements was $10.8 million, $6.7 million and $1.1 million for the periods ended Dec. 31, 2014, 2013 and 2012, respectively. The income tax benefit realized from stock option exercises was $1.0 million, $0.8 million and $0.1 million for the periods ended Dec. 31, 2014, 2013 and 2012, respectively.

A summary of non-vested shares of restricted stock is shown as follows:

Nonvested Restricted Stock

	Time-Based Restricted Stock (1)		Performance-Based Restricted Stock (1)	
	Number of Shares (thousands)	Weighted-Avg. Grant Date Fair Value (per share)	Number of Shares (thousands)	Weighted-Avg. Grant Date Fair Value (per share)
Nonvested balance at Dec. 31, 2013	638	$ 18.33	1,505	$ 17.04
Granted	265	$ 16.93	537	$ 13.59
Vested	(200)	$ 19.16	(444)	$ 18.53
Forfeited	(35)	$ 17.51	(83)	$ 15.51
Nonvested balance at Dec. 31, 2014	668	$ 17.56	1,515	$ 15.44

(1) The weighted-average remaining contractual term of restricted stock is two years.

Stock option transactions are summarized as follows:

Stock Options

	Number of Shares (thousands)	Weighted-Avg. Option Price (per share)	Weighted-Avg. Remaining Contractual Term (years)	Aggregate Intrinsic Value (millions)
Outstanding balance at Dec. 31, 2013	1,567	$ 15.62		
Granted	0	$ 0.00		
Exercised	(727)	$ 14.80		
Cancelled	0	$ 0.00		
Outstanding balance at Dec. 31, 2014(1)	840	$ 16.32	1	$ 3.5
Exercisable at Dec. 31, 2014 (1)	840	$ 16.32	1	$ 3.5
Available for future grant at Dec. 31, 2014	2,482			

(1) Option prices range from $16.21 to $19.01 per share.

As of Dec. 31, 2014, the options outstanding and exercisable are summarized below:

Range of Option Prices (per share)	Option Shares (thousands)	Weighted-Avg. Option Price (per share)	Weighted-Avg. Remaining Contractual Life (years)
$16.21 — $ 19.01	840	$ 16.32	1
Total	840	$ 16.32	1

Direct Stock Purchase and Dividend Reinvestment Plan

In September 2014, the Direct Stock Purchase and Dividend Plan amended and restated the 1992 Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy purchased shares on the open market for this plan in 2014, 2013 and 2012, resulting in no increase in shares outstanding.

10. Other Comprehensive Income

TECO Energy reported the following OCI (loss) for the years ended Dec. 31, 2014, 2013 and 2012, related to changes in the fair value of cash flow hedges and amortization of unrecognized benefit costs associated with the company's pension plans:

(millions)	Gross	Tax	Net
2014			
Unrealized gain (loss) on cash flow hedges	$(0.5)	$0.2	$(0.3)
Reclassification from AOCI to net income (1)	1.6	(0.6)	1.0
Gain (Loss) on cash flow hedges	1.1	(0.4)	0.7
Amortization of unrecognized benefit costs and other (2)	(4.8)	1.8	(3.0)
Increase in unrecognized postemployment costs (3)	(12.9)	4.7	(8.2)
Change in benefit obligation due to remeasurement (4)	12.6	(4.6)	8.0
Total other comprehensive income (loss)	$(4.0)	$1.5	$(2.5)
2013			
Unrealized gain (loss) on cash flow hedges	$1.0	$(0.4)	$0.6
Reclassification from AOCI to net income (1)	1.3	(0.5)	0.8
Gain (Loss) on cash flow hedges	2.3	(0.9)	1.4
Amortization of unrecognized benefit costs and other (2)	23.6	(8.8)	14.8
Recognized benefit costs due to settlement	2.6	(1.0)	1.6
Total other comprehensive income (loss)	$28.5	$(10.7)	$17.8
2012			
Unrealized gain (loss) on cash flow hedges	$(7.4)	$2.8	$(4.6)
Reclassification from AOCI to net income (1)	0.6	(0.2)	0.4
Gain (Loss) on cash flow hedges	(6.8)	2.6	(4.2)
Amortization of unrecognized benefit costs and other (2)(5)	(4.8)	0.0	(4.8)
Total other comprehensive income (loss)	$(11.6)	$2.6	$(9.0)

(1) Related to interest rate contracts in Interest expense and commodity contracts recognized in Income (loss) from discontinued operations.
(2) Related to postretirement and postemployment benefits. See Note 5 for additional information.
(3) Amounts reflect an out-of-period adjustment related to TECO Coal's unfunded black lung liability.
(4) Includes an adjustment to eliminate TECO Coal's OPEB liability. See Note 5 for additional information.
(5) Tax amounts include adjustments made related to Medicare Part D and changes to retirement plan. See Note 5 for further discussion.

Accumulated Other Comprehensive Loss

(millions) Dec. 31,	2014	2013
Unrecognized pension losses and prior service credits (1)	$(22.5)	$(20.5)
Unrecognized other benefit gains, prior service costs and transition obligations (2)	13.9	15.1
Net unrealized losses from cash flow hedges (3)	(7.1)	(7.8)
Total accumulated other comprehensive loss	$(15.7)	$(13.2)

(1) Net of tax benefit of $13.8 million and $12.6 million as of Dec. 31, 2014 and Dec. 31, 2013, respectively.
(2) Net of tax expense of $8.3 million and $9.1 million as of Dec. 31, 2014 and Dec. 31, 2013, respectively. Balance includes a $7.9 million loss at Dec. 31, 2014 related to TECO Coal's unfunded black lung liability that will be reclassified from AOCI to net income from discontinued operations upon the settlement of the black lung obligation at the sale date. See Note 5.

(3) Net of tax benefit of $4.5 million and $4.9 million as of Dec. 31, 2014 and Dec. 31, 2013, respectively.

11. Earnings Per Share

In accordance with accounting standards for the calculation of EPS, TECO Energy follows the two-class method for computing EPS. These standards define share-based payment awards that participate in dividends prior to vesting as participating securities that should be included in the earnings allocation in computing EPS under the two-class method.

The two-class method of calculating EPS requires TECO Energy to calculate EPS for its common stock and its participating securities (time-vested restricted stock and performance-based restricted stock) based on dividends declared and the pro-rata share each has to undistributed earnings. The application of the two-class method did not have a material effect on TECO Energy’s EPS calculations.

(millions, except per share amounts)	2014	2013 (1)	2012 (1)
Basic earnings per share			
Net income from continuing operations	$206.4	$188.7	$197.0
Amount allocated to nonvested participating shareholders	(0.7)	(0.6)	(0.7)
Income before discontinued operations available to common shareholders—Basic	$205.7	$188.1	$196.3
Income (loss) from discontinued operations attributable to TECO Energy, net	$(76.0)	$9.0	$15.7
Amount allocated to nonvested participating shareholders	0.0	0.0	0.0
Income (loss) from discontinued operations attributable to TECO Energy available to common shareholders—Basic	$(76.0)	$9.0	$15.7
Net income attributable to TECO Energy	$130.4	$197.7	$212.7
Amount allocated to nonvested participating shareholders	(0.7)	(0.6)	(0.7)
Net income attributable to TECO Energy available to common shareholders—Basic	$129.7	$197.1	$212.0
Average common shares outstanding—Basic	223.1	215.0	214.3
Earnings per share from continuing operations available to common shareholders—Basic	$0.92	$0.88	$0.92
Earnings per share from discontinued operations attributable to TECO Energy available to common shareholders—Basic	$(0.34)	$0.04	$0.07
Earnings per share attributable to TECO Energy available to common shareholders—Basic	$0.58	$0.92	$0.99
Diluted earnings per share			
Net income from continuing operations	$206.4	$188.7	$197.0
Amount allocated to nonvested participating shareholders	(0.7)	(0.6)	(0.7)
Income before discontinued operations available to common shareholders—Diluted	$205.7	$188.1	$196.3
Income (loss) from discontinued operations attributable to TECO Energy, net	$(76.0)	$9.0	$15.7
Amount allocated to nonvested participating shareholders	0.0	0.0	0.0
Income (loss) from discontinued operations attributable to TECO Energy available to common	$(76.0)	$9.0	$15.7

shareholders—Diluted			
Net income attributable to TECO Energy	$130.4	$197.7	$212.7
Amount allocated to nonvested participating shareholders	(0.7)	(0.6)	(0.7)
Net income attributable to TECO Energy available to common shareholders—Diluted	$129.7	$197.1	$212.0
Unadjusted average common shares outstanding—Diluted	223.1	215.0	214.3
Assumed conversion of stock options, unvested restricted stock and contingent performance shares, net	0.6	0.5	0.7
Average common shares outstanding—Diluted	223.7	215.5	215.0
Earnings per share from continuing operations available to common shareholders—Diluted	$0.92	$0.88	$0.92
Earnings per share from discontinued operations attributable to TECO Energy available to common shareholders—Diluted	$(0.34)	$0.04	$0.07
Earnings per share attributable to TECO Energy available to common shareholders—Diluted	$0.58	$0.92	$0.99
Anti-dilutive shares	0.0	0.0	0.4

(1) All prior periods presented reflect the classification of TECO Coal as discontinued operations (see Note 19).

12. Commitments and Contingencies

Legal Contingencies

From time to time, TECO Energy and its subsidiaries are involved in various legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with accounting standards for contingencies to provide for matters that are probable of resulting in an estimable loss. While the outcome of such proceedings is uncertain, management does not believe that their ultimate resolution will have a material adverse effect on the company's results of operations, financial condition or cash flows.

Peoples Gas Legal Proceedings

In November 2010, heavy equipment operated at a road construction site being conducted by Posen Construction, Inc. struck a natural gas line causing a rupture and ignition of the gas and an outage in the natural gas service to Lee and Collier counties, Florida. PGS filed suit in April 2011 against Posen Construction, Inc. in Federal Court for the Middle District of Florida to recover damages for repair and restoration relating to the incident and Posen Construction, Inc. counter-claimed against PGS alleging negligence. In the first quarter of 2014, the parties entered into a settlement agreement that resolves the claims of the parties. In addition, the suit filed in November 2011 by the Posen Construction, Inc. employee operating the heavy equipment involved in the incident in Lee County Circuit Court against PGS and a PGS contractor involved in the project, seeking damages for his injuries, remains pending.

Tampa Electric Legal Proceedings

Three former or inactive TEC employees were maintaining a suit against TEC in Hillsborough County Circuit Court, Florida for personal injuries allegedly caused by exposure to a chemical substance at one of TEC's power stations. The suit was originally filed in 2002, and the trial judge allowed the plaintiffs to seek punitive damages in connection with their case. In the first quarter of 2014, all plaintiffs voluntarily dismissed their suits with prejudice.

A thirty-six year old man died from mesothelioma in March 2014. His estate and his family are suing Tampa Electric as a result. The man allegedly suffered exposure to asbestos dust brought home by his father and grandfather, both of whom had been employed as insulators and worked at various job sites throughout the Tampa area. Plaintiff's case against Tampa Electric and nineteen other defendants alleges, among other things, negligence, strict liability, household exposure, loss of consortium, and wrongful death.

In September 2014, a man was electrocuted when allegedly two energized, downed primary conductors fell during a heavy storm, leading to his death. Plaintiff's wrongful death complaint against Tampa Electric alleges, among other things, negligence and code violations.

New Mexico Gas Company Legal Proceedings

In February 2011, NMGC experienced gas shortages due to weather-related interruptions of electric service, weather-related problems on the systems of various interstate pipelines and in gas fields that are the sources of gas supplied to NMGC, and high weather-driven usage. This gas supply disruption and high usage resulted in the declaration of system emergencies by NMGC causing involuntary curtailments of gas utility service to approximately 28,700 customers (residential and business).

In March 2011, a customer purporting to represent a class consisting of all "32,000 [sic] customers" who had their gas utility service curtailed during the early-February system emergencies filed a putative class action lawsuit against NMGC. In March 2011, the Town of Bernalillo, New Mexico, purporting to represent a class consisting of all "New Mexico municipalities and governmental entities who have suffered damages as a result of the natural gas utility shut off" also filed a putative class action lawsuit against NMGC, four of its officers, and John and Jane Does at NMGC. In July 2011, the plaintiff in the Bernalillo class action filed an amended complaint to add an additional plaintiff purporting to represent a class of all "similarly situated New Mexico private businesses and enterprises."

The two purported class action suits (three purported classes) were consolidated. The court dismissed the class actions in their entirety with prejudice in October 2014 and appeals from the dismissal were taken by the plaintiffs in November 2014 and are pending.

Two lawsuits representing 18 insurance carriers have filed subrogation lawsuits for monies paid to their insureds as a result of the curtailment of natural gas service in February 2011. These subrogation matters are pending and discovery is proceeding. NMGC has filed motions to dismiss similar to those previously filed and ruled on favorably in the class actions.

The company believes the claims in the pending actions described above in this item are without merit and intends to defend each matter vigorously. The company is unable at this time to estimate the possible loss or range of loss with respect to these matters.

TECO Guatemala Holdings, LLC v. The Republic of Guatemala

On Dec. 19, 2013, the ICSID Tribunal hearing the arbitration claim of TGH, a wholly owned subsidiary of TECO Energy, against the Republic of Guatemala (Guatemala) under the DR-CAFTA, issued an award in the case (the Award). The ICSID Tribunal unanimously found in favor of TGH and awarded damages to TGH of approximately U.S. $21.1 million, plus interest from Oct. 21, 2010 at a rate equal to the U.S. prime rate plus 2%. In addition, the Tribunal ruled that Guatemala must reimburse TGH for approximately U.S. $7.5 million of the costs that it incurred in pursuing the arbitration.

On Apr. 18, 2014, Guatemala filed an application for annulment of the entire Award (or, alternatively, certain parts of the Award) pursuant to applicable ICSID rules. Guatemala also requested that the enforcement of the Award be stayed while the annulment proceeding is pending. Under the applicable rules, the enforcement of the Award is provisionally stayed until the ad hoc committee constituted for purposes of deciding Guatemala's application makes a decision regarding whether the stay should continue through the rest of the annulment proceeding.

Also on Apr. 18, 2014, TGH separately filed an application for partial annulment of the Award on the basis of certain deficiencies in the Tribunal’s determination of the amount of TGH’s damages. If TGH’s application is successful, TGH will be able to seek additional damages from Guatemala in a new arbitration proceeding.

While the duration of the annulment proceedings is uncertain, a hearing is scheduled in October 2015 and the proceedings as a whole are expected to take approximately two years to conclude, with a decision by the ad hoc committee in mid- to late-2016. Pending the outcome of annulment proceedings, results to date do not reflect any benefit of this decision.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and Peoples Gas divisions, is a PRP for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2014, TEC has estimated its ultimate financial liability to be $33.3 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under “Other” on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer rates.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC’s experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC’s actual percentage of the remediation costs.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Long-Term Commitments

TECO Energy has commitments under long-term leases, primarily for building space, capacity payments, vehicles, office equipment and heavy equipment. Rental expense for these leases included in “Regulated operations and maintenance – Other”, “Operation & maintenance other expense – Other” and “Discontinued Operations” on the Consolidated Statements of Income for the years ended Dec. 31, 2014, 2013 and 2012 totaled \$13.7 million, \$7.6 million and \$8.1 million, respectively. In addition, the company has other purchase obligations, including Tampa Electric’s outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year, capacity payments under PPAs, and other net purchase obligations/commitments at Dec. 31, 2014:

(millions)	Capacity Payments	Operating Leases(1)	Net Purchase Obligations/Commitments(1)	Total
Year ended Dec. 31:				
2015	$ 30.0	$ 8.9	$ 204.5	$243.4
2016	14.6	8.0	86.8	109.4
2017	9.9	7.0	19.8	36.7
2018	10.1	6.2	5.2	21.5
2019	0.0	5.7	5.3	11.0
Thereafter	0.0	18.4	0.0	18.4
Total future minimum payments	$ 64.6	$ 54.2	$ 321.6	$440.4

(1) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. The table above excludes payment obligations under contractual agreements of Tampa Electric, PGS and NMGC for fuel, fuel transportation and power purchases which are recovered from customers under regulatory clauses.

Guarantees and Letters of Credit

TECO Energy accounts for guarantees in accordance with the applicable accounting standards. Upon issuance or modification of a guarantee the company determines if the obligation is subject to either or both of the following:

Initial recognition and initial measurement of a liability, and/or
Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative) are likely to be subject to the recognition and measurement, as well as the disclosure provisions. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

A summary of the face amount or maximum theoretical obligation under TECO Energy’s letters of credit and guarantees as of Dec. 31, 2014 are as follows:

(millions)	Year of Expiration			Maximum	
			After [1]	Theoretical	Liabilities Recognized
Guarantees for the Benefit of:	2015	2016-2019	2019	Obligation	at Dec. 31, 2014 [2]
TECO Energy					
Fuel sales and transportation [2]	$0.0	$ 0.0	$ 92.9	92.9	$ 0.0

(millions)	Year of Expiration			Maximum	
			After [1]	Theoretical	Liabilities Recognized
Letter of Credit for the Benefit of:	2015	2016-2019	2019	Obligation	at Dec. 31, 2014 [2]
TEC	$0.0	$ 0.0	$ 0.6	$ 0.6	$ 0.1
NMGC	$0.0	$ 0.0	$ 1.7	$ 1.7	$ 0.0

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2019.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy, TEC or NMGC under these agreements at Dec. 31, 2014. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.

Financial Covenants

In order to utilize their respective bank credit facilities, TECO Energy and its subsidiaries must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy and its subsidiaries have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2014, TECO Energy and its subsidiaries were in compliance with all required financial covenants.

13. Related Parties

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. The company paid legal fees of $1.7 million and $1.3 million for the years ended Dec. 31, 2013 and 2012, respectively, to Ausley McMullen, P.A. of which Mr. DuBose Ausley (who was a director of TECO Energy, until his retirement from the Board in May 2013) was an employee. Other transactions were not material for the years ended Dec. 31, 2014, 2013 and 2012. No material balances were payable as of Dec. 31, 2014 or 2013.

14. Segment Information

TECO Energy is primarily an electric and gas utility holding company. Its diversified activities have been classified as discontinued operations. Segments are determined based on how management evaluates, measures and makes decisions with respect to the operations of the entity. The management of TECO Energy reports segments based on each segment's contribution of revenues, net income and total assets as required by the accounting guidance for disclosures about segments of an enterprise and related information. All significant intercompany transactions are eliminated in the Consolidated Financial Statements of TECO Energy, but are included in determining reportable segments.

Tampa Electric provides retail electric utility services to more than 706,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for almost 354,000 residential, commercial, industrial and electric power generation customers in the State of Florida. NMGC is engaged in the purchase and distribution of natural gas for approximately 513,000 residential, commercial, industrial customers in the State of New Mexico.

(millions)	Tampa Electric	PGS	NMGC [4]	TECO Coal [2]	TECO Guatemala [2]	Other [4]	Eliminations	TECO Energy
2014								
Revenues—external	$2,019.9	$398.5	$137.5	$0.0	$ 0.0	$10.5	$0.0	$2,566.4
Sales to affiliates	1.1	1.1	0.0	0.0	0.0	40.6	(42.8)	0.0
Total revenues	2,021.0	399.6	137.5	0.0	0.0	51.1	(42.8)	2,566.4
Depreciation and amortization	248.6	54.0	11.0	0.0	0.0	1.7	0.0	315.3
Total interest charges [1]	92.8	13.8	4.2	0.0	0.0	66.1	(5.8)	171.1
Internally allocated interest [1]	0.0	0.0	0.0	0.0	0.0	1.4	(1.4)	0.0
Provision for income taxes	133.2	22.7	7.1	0.0	0.0	(24.1)	0.0	138.9
Net income from continuing operations	224.5	35.8	10.5	0.0	0.0	17.8	(82.2)	206.4
Discontinued operations attributable to TECO, net of tax	0.0	0.0	0.0	(82.0)	0.0	6.0	0.0	(76.0)
Net income attributable to TECO Energy	224.5	35.8	10.5	(82.0)	0.0	23.8	(82.2)	130.4
Current assets held for sale	0.0	0.0	0.0	109.6	0.0	0.0	0.0	109.6
Non-current assets held for sale	0.0	0.0	0.0	59.8	0.0	0.0	0.0	59.8
Goodwill	0.0	0.0	408.3	0.0	0.0	0.0	0.0	408.3
Total assets	6,565.4	1,082.8	1,237.2	227.7 [3]	0.0	5,664.4	(6,051.3)	8,726.2
Capital expenditures	592.6	88.9	18.2	14.6	0.0	0.0	0.0	714.3
2013								
Revenues—external	$1,949.6	$392.7	$0.0	$0.0	$ 0.0	$12.8	$0.0	$2,355.1
Sales to affiliates	0.9	0.8	0.0	0.0	0.0	0.5	(2.2)	0.0
Total revenues	1,950.5	393.5	0.0	0.0	0.0	13.3	(2.2)	2,355.1
Depreciation and amortization	238.8	51.5	0.0	0.0	0.0	1.5	0.0	291.8
Total interest charges [1]	91.8	13.5	0.0	0.0	0.0	63.9	(7.8)	161.4
Internally allocated interest [1]	0.0	0.0	0.0	0.0	0.0	7.8	(7.8)	0.0
Provision for income taxes	116.9	21.9	0.0	0.0	0.0	(26.2)	0.0	112.6
Net income from continuing operations	190.9	34.7	0.0	0.0	0.0	177.3	(214.2)	188.7
Discontinued operations attributable to TECO, net of tax	0.0	0.0	0.0	9.0	0.0	0.0	0.0	9.0
Net income attributable to TECO Energy	190.9	34.7	0.0	9.0	0.0	177.3	(214.2)	197.7

Total assets	6,126.9	1,021.2	0.0	316.3	(3)	0.0	4,717.2	(4,733.6)	7,448.0
Capital expenditures	428.6	79.0	0.0	22.4		0.0	2.4	-	532.4
2012									
Revenues—external	$1,980.7	$396.6	$0.0	$0.0		$ 0.0	$10.4	$0.0	$2,387.7
Sales to affiliates	0.6	2.3	0.0	0.0		0.0	0.1	(3.0)	0.0
Total revenues	1,981.3	398.9	0.0	0.0		0.0	10.5	(3.0)	2,387.7
Depreciation and amortization	237.6	50.6	0.0	0.0		0.0	1.4	0.0	289.6
Total interest charges (1)	109.8	16.0	0.0	0.0		0.0	64.1	(13.5)	176.4
Internally allocated interest (1)	0.0	0.0	0.0	0.0		0.0	13.5	(13.5)	0.0
Provision for income taxes	120.2	21.5	0.0	0.0		0.0	(20.9)	0.0	120.8
Net income from continuing operations	193.1	34.1	0.0	0.0		0.0	241.3	(271.5)	197.0
Discontinued operations attributable to TECO, net of tax	0.0	0.0	0.0	50.2		(29.3)	(5.2)	0.0	15.7
Net income attributable to TECO Energy	193.1	34.1	0.0	50.2		(29.3)	236.1	(271.5)	212.7
Total assets	6,042.3	1,009.9	0.0	356.6	(3)	164.9	4,870.0	(5,108.8)	7,334.9
Capital expenditures	361.7	97.3	0.0	36.3		8.6	1.2	0.0	505.1

(1) Segment net income is reported on a basis that includes internally allocated financing costs. Total interest charges include internally allocated interest costs that for 2014, 2013 and 2012 were at a pretax rate of 6.00%, based on an average of each subsidiary's equity and indebtedness to TECO Energy assuming a 50/50 debt/equity capital structure.

(2) All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for TECO Coal, TECO Guatemala and certain charges at Parent that directly relate to TECO Coal or TECO Guatemala. See Note 19.

(3) The carrying value of mineral rights as of Dec. 31, 2014, 2013 and 2012 was $10.9 million, $12.1 million and $13.4 million, respectively.
(4) NMGI is included in the Other segment.

15. Asset Retirement Obligations

TECO Energy accounts for AROs under the applicable accounting standards. An ARO for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its estimated future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

TECO Energy has recognized AROs for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities at TECO Coal. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations. At Dec. 31, 2014 and 2013, these obligations totaled $22.5 million and $23.8 million, respectively, and are classified as Liabilities Associated with Assets Held for Sale on TECO Energy's Consolidated Balance Sheets.

Our regulated utilities must file depreciation and dismantlement studies periodically and receive approval from the FPSC or NMPRC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components—a salvage factor and a cost of removal or dismantlement factor. The company uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

For Tampa Electric and NMGC, the original cost of utility plant retired or otherwise disposed of and the cost of removal or dismantlement, less salvage value, is charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively. At Dec. 31, 2014 and 2013, these obligations totaled $6.1 million and $4.8 million, respectively.

Reconciliation of beginning and ending carrying amount of asset retirement obligations:

	Dec. 31,	
(millions)	2014	2013
Beginning balance	$28.6	$28.6
Additional liabilities	0.1	0.1
Liabilities settled	0.0	(1.4)
Accretion expense	0.0	1.4
Revisions to estimated cash flows	0.2	(0.3)
Acquisition of NMGC	0.8	0.0
Reclassification to liabilities associated with assets held for sale	(22.5)	0.0

Other [1]	(1.1)	0.2
Ending balance	$6.1	$28.6

(1) 2014 includes $(1.3) million of activity associated with TECO Coal and classified as discontinued operations and $0.2 million accretion recorded as a deferred regulatory asset. 2013 includes accretion recorded as a deferred regulatory asset.

16. Accounting for Derivative Instruments and Hedging Activities

From time to time, TECO Energy and its affiliates enter into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric, PGS and NMGC;
- To limit the exposure to interest rate fluctuations on debt securities at TECO Energy and its affiliates; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Coal (all of which were settled prior to Dec. 31, 2014).

TECO Energy and its affiliates use derivatives only to reduce normal operating and market risks, not for speculative purposes. The regulated utilities' primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers.

The risk management policies adopted by TECO Energy provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group, which is independent of all operating companies.

The company applies the accounting standards for derivative instruments and hedging activities. These standards require companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value and to reflect the changes in the fair value of those instruments as either components of OCI or in net income, depending on the designation of those instruments (see Note 17). The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of the instrument's settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the market change of the amount paid or received on the underlying physical transaction.

The company applies the accounting standards for regulated operations to financial instruments used to hedge the purchase of natural gas for its regulated companies. These standards, in accordance with the FPSC and NMPRC, permit the changes in fair value of natural gas derivatives to be recorded as regulatory assets or liabilities reflecting the impact of hedging activities on the fuel recovery clause. As a result, these changes are not recorded in OCI (see Note 3).

The company's physical contracts qualify for the NPNS exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if the company deems the counterparty creditworthy, if the counterparty owns or controls resources within the proximity to allow for physical delivery of the commodity, if the company intends to receive physical delivery and if the transaction is reasonable in relation to the company's business needs. As of Dec. 31, 2014, all of the company's physical contracts qualify for the NPNS exception.

The derivatives that are designated as cash flow hedges at Dec. 31, 2014 and 2013 are reflected on the company's Consolidated Balance Sheets and classified accordingly as current and long term assets and liabilities on a net basis as permitted by their respective master netting agreements. Derivative assets totaled $0 and $10.0 million as of Dec. 31, 2014 and 2013, respectively, and derivative liabilities totaled $42.7 million and $0.3 million as of Dec. 31, 2014 and 2013, respectively. There are minor offset amount differences between the gross derivative assets and liabilities and the net amounts presented on the Consolidated Balance Sheets. There was no collateral posted with or received from any counterparties.

All of the derivative asset and liabilities at Dec. 31, 2014 and 2013 are designated as hedging instruments, which primarily are derivative hedges of natural gas contracts to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers. The corresponding effect of these natural gas related derivatives on the regulated utilities' fuel recovery clause mechanism is reflected on the Consolidated Balance Sheets as current and long term regulatory assets and liabilities. Based on the fair value of the instruments at Dec. 31, 2014, net pretax losses of $36.6 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The Dec. 31, 2014 and 2013 balance in AOCI related to the cash flow hedges and previously settled interest rate swaps is presented in Note 10.

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or period during which the hedged transaction affects earnings. Gains and losses on the derivatives representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For the years ended Dec. 31, 2014, 2013 and 2012, all hedges were effective. The derivative after-tax effect on OCI and the amount of after-tax gain or loss reclassified from AOCI into earnings for years ended Dec. 31, 2014, 2013 and 2012 is presented in Note 10. These gains and losses were the result of interest rate contracts for TEC and diesel fuel derivatives related to TECO Coal operations. The locations of the reclassifications to income were reflected in Interest expense for TEC and Income (loss) from discontinued operations for TECO Coal.

The maximum length of time over which the company is hedging its exposure to the variability in future cash flows extends to Dec. 31, 2016 for financial natural gas contracts. There is no diesel fuel contract exposure beyond 2014. The following table presents the company's derivative volumes that, as of Dec. 31, 2014, are expected to settle during the 2015 and 2016 fiscal years:

(millions)	Natural Gas Contracts (MMBTUs)	
Year	Physical	Financial
2015	0.0	32.4
2016	0.0	8.6
Total	0.0	41.0

The company is exposed to credit risk primarily through entering into derivative instruments with counterparties to limit its exposure to the commodity price fluctuations associated with natural gas. Credit risk is the potential loss resulting from a counterparty's nonperformance under an agreement. The company manages credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement and exposure monitoring and mitigation.

It is possible that volatility in commodity prices could cause the company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the company could suffer a material financial loss. However, as of Dec. 31, 2014, substantially all of the counterparties with transaction amounts outstanding in the company's energy portfolio were rated investment grade by the major rating agencies. The company assesses credit risk internally for counterparties that are not rated.

The company has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. The company generally enters into the following master arrangements: (1) EEI agreements—standardized power sales contracts in the electric industry; (2) ISDA agreements—standardized financial gas and electric contracts; and (3) NAESB agreements—standardized physical gas contracts. The company believes that entering into such agreements reduces the risk from default by creating contractual rights relating to creditworthiness, collateral and termination.

The company has implemented procedures to monitor the creditworthiness of its counterparties and to consider nonperformance risk in determining the fair value of counterparty positions. Net liability positions are generally not adjusted as the company uses derivative transactions as hedges and has the ability and intent to perform under each of these contracts. In the instance of net asset positions, the company considers general market conditions and the observable financial health and outlook of specific counterparties in evaluating the potential impact of nonperformance risk to derivative positions. As of Dec. 31, 2014, all positions with counterparties were net liabilities.

Certain TECO Energy derivative instruments contain provisions that require the company's debt, or in the case of derivative instruments where TEC is the counterparty, TEC's debt, to maintain an investment grade credit rating from any or all of the major credit rating agencies. If debt ratings, including TEC's, were to fall below investment grade, it could trigger these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The company has no other contingent risk features associated with any derivative instruments.

17. Fair Value Measurements

Items Measured at Fair Value on a Recurring Basis

Accounting guidance governing fair value measurements and disclosures provides that fair value represents the amount that would be received in selling an asset or the amount that would be paid in transferring a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that is determined based upon assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, accounting guidance also establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1: Observable inputs, such as quoted prices in active markets;

Level 2: Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and

Level 3: Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities are measured at fair value based on one or more of the following three valuation techniques noted under accounting guidance:

(A) Market approach: Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities;
(B) Cost approach: Amount that would be required to replace the service capacity of an asset (replacement cost); and
(C) Income approach: Techniques to convert future amounts to a single present amount based upon market expectations (including present value techniques, option-pricing and excess earnings models).

The fair value of financial instruments is determined by using various market data and other valuation techniques.

The following tables set forth by level within the fair value hierarchy, the company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of Dec. 31, 2014 and 2013. As required by accounting standards for fair value measurements, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For natural gas and diesel fuel swaps, the market approach was used in determining fair value.

Recurring Fair Value Measures

	As of Dec. 31, 2014			
(millions)	Level	Level 2	Level 3	Total
Liabilities				
Natural gas swaps	$0.0	$ 42.7	$ 0.0	$42.7

	As of Dec. 31, 2013			
(millions)	Level	Level 2	Level 3	Total
Assets				
Natural gas swaps	$0.0	$ 9.8	$ 0.0	$9.8
Diesel fuel swaps	0.0	0.2	0.0	0.2
Total	$0.0	$ 10.0	$ 0.0	$10.0
Liabilities				
Natural gas swaps	$0.0	$ 0.2	$ 0.0	$0.2
Diesel fuel swaps	0.0	0.1	0.0	0.1
Total	$0.0	$ 0.3	$ 0.0	$0.3

Natural gas and diesel fuel swaps are OTC swap instruments. The primary pricing inputs in determining the fair value of these swaps are the NYMEX quoted closing prices of exchange-traded instruments. These prices are applied to the notional amounts of active positions to determine the reported fair value (see Note 16).

The company considered the impact of nonperformance risk in determining the fair value of derivatives. The company considered the net position with each counterparty, past performance of both parties, the intent of the parties, indications of credit deterioration and whether the markets in which the company transacts have experienced dislocation. At Dec. 31, 2014, the fair value of derivatives was not materially affected by nonperformance risk. There were no Level 3 assets or liabilities for the periods presented.

See Notes 5, 7 and 20 for information regarding the fair value of the company's pension plan investments, long-term debt, and asset impairment charge, respectively.

18. Variable Interest Entities

The determination of a VIE's primary beneficiary is the enterprise that has both 1) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and 2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

TEC has entered into multiple PPAs with wholesale energy providers in Florida to ensure the ability to meet customer energy demand and to provide lower cost options in the meeting of this demand. These agreements range in size from 117 MW to 370 MW of available capacity, are with similar entities and contain similar provisions. Because some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy, these agreements meet the definition of being VIEs. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. TEC has reviewed these risks and has determined that the owners of these entities have retained the majority of these risks over the expected life of the underlying generating assets, have the power to direct the most significant activities, the obligation or right to absorb losses or benefits and hence remain the primary beneficiaries. As a result, TEC is not required to consolidate any of these entities. TEC purchased $25.7 million, $22.1 million and $75.8 million, under these PPAs for the three years ended Dec. 31, 2014, 2013 and 2012, respectively.

The company does not provide any material financial or other support to any of the VIEs it is involved with, nor is the company under any obligation to absorb losses associated with these VIEs. In the normal course of business, the company's involvement with these VIEs does not affect its Consolidated Balance Sheets, Statements of Income or Cash Flows.

19. Discontinued Operations

TECO Coal

On Sept. 29, 2014, the Board of Directors of TECO Energy authorized management to enter into negotiations for the sale of TECO Coal. As a result of this and other factors, the TECO Coal segment was accounted for as an asset held for sale and reported as a discontinued operation at Sept. 30, 2014, which for the third quarter 2014 included a pretax $98.4 million impairment charge related to the held-for-sale TECO Coal assets (see Note 20 for further information regarding the impairment charge).

On Oct. 17, 2014, TECO Diversified entered into an SPA to sell all of its ownership interest in TECO Coal to Cambrian Coal Corporation for $120 million plus contingent payments of up to $50 million that may be paid between 2015 and 2019 depending on specified coal benchmark prices. On Dec. 24, 2014, the SPA was amended to extend the closing date to Feb. 20, 2015. As reported in Note 23, on Feb. 5, 2015, the SPA was further amended to extend the closing date to Mar. 13, 2015 and modify the purchase price to $80 million, subject to working capital adjustments, plus contingent payments of up to $60 million. As a result of the amended purchase price an additional pretax $17.5 million impairment charge related to the held-for-sale TECO Coal assets was recorded in discontinued operations in the fourth quarter 2014, which resulted in a total pretax impairment charge of $115.9 million for the year ended Dec. 31, 2014 (see Note 20).

The SPA contains customary representations, warranties, covenants, and closing conditions, including the purchaser's obtaining debt financing in order to pay a portion of the purchase price. The SPA also contains indemnification provisions subject to specified limitations as to time and amount. In addition, the SPA, as amended, is subject to termination by either party if specified closing conditions are not met by Mar. 13, 2015. After closing of the sale, TECO Energy will not have influence over operations of TECO Coal, therefore the contingent payments and indemnification provisions are not considered to meet the definition of direct cash flows under the applicable discontinued operations FASB guidance.

All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for TECO Coal and certain fourth quarter 2014 charges at Parent that directly relate to the sale of TECO Coal.

The following table provides a summary of the carrying amounts of the significant assets and liabilities reported in the combined current and non-current "Assets held for sale" and "Liabilities associated with assets held for sale" line items:

Assets held for sale

(millions)	Dec. 31, 2014
Current assets	$109.6
Property, plant and equipment, net and other long-term assets	59.8
Total assets held for sale	$169.4

Liabilities associated with assets held for sale

(millions)	
Current liabilities	$39.4
Long-term liabilities	65.4
Total liabilities associated with assets held for sale	$104.8

TECO Guatemala

On Aug. 7, 2012, TECO Energy received an offer from Renewable Energy Investments Guatemala Limited (REIN), a wholly-owned subsidiary of Sur Eléctrica Holding Limited (SUR), to purchase the independent power projects in Guatemala and certain affiliated Guatemala companies. On Sept. 27, 2012, an indirect wholly-owned subsidiary of TECO Energy, Inc., TECO Guatemala Holdings II, LLC (TGH), entered into an equity purchase agreement with SUR, and two equity purchase agreements with REIN (the three equity purchase agreements are collectively referred to herein as the “PAs”). Pursuant to the PA with SUR, TGH agreed to sell all of its ownership interests in TPS Guatemala One, Ltd. (TPS GO) for $12.5 million, and pursuant to the PAs with REIN, it agreed to sell all of its ownership interests in (i) TPS San José International, Inc. (TPS SJI) for $213.5 million and (ii) TECO Guatemala Services, Ltd. (TGS) for $1.5 million (TPS GO, TPS SJI and TGS are collectively referred to herein as the Disposal Group). The companies in the Disposal Group were the ultimate parent companies of TCAE, CGESJ, TEMSA, and TPS Operaciones de Guatemala, Limitada (TPSO), the owner of certain local real estate assets and the employer of the local employees. The total purchase price for the Disposal Group under the PAs was $227.5 million.

The sale of TPS GO, which owned 96.06% of TCAE, closed on Sept. 27, 2012. An affiliate of the party that controlled the remaining interest in TCAE (the “noncontrolling interest holder”) held certain contractual rights with respect to TEMSA and CGESJ, including a right of first offer. The noncontrolling interest holder was also granted the opportunity to purchase TGS since the operations of TPSO were integral to the operations of TEMSA and CGESJ. The noncontrolling interest holder exercised the right of first offer for TPS SJI and elected to purchase TGS by executing PAs similar to the PAs with REIN on Oct. 17, 2012 and Oct. 26, 2012, respectively. The sales of TPS SJI and TGS to the noncontrolling interest holder closed on Dec. 19, 2012.

The PAs contain customary representations, warranties, covenants and indemnification provisions subject to specified limitations as to time and amount. As a result of the PAs, the TECO Guatemala segment was accounted for as a discontinued operation beginning in the third quarter of 2012. All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for TECO Guatemala and certain items at Parent that directly relate to TECO Guatemala.

Net proceeds from the sale of all Guatemalan operations, after transaction-related costs and the $25.3 million repayment of the San José power station project debt, were approximately $197.0 million. The sale resulted in an after-tax book loss and an after-tax charge associated with foreign tax credits of $28.6 million and $22.9 million, respectively.

The provision for income taxes line item related to TECO Guatemala in the table below includes an after-tax charge of $22.9 million in 2012 associated with foreign tax credits. The 2012 charge is a result of the sales of the Disposal Group which eliminate future foreign source income that would be required to utilize these credits.

As reported in Note 12, while TECO Energy and its subsidiaries no longer have assets or operations in Guatemala, its subsidiary, TECO Guatemala Holdings, LLC, has retained its rights under its arbitration claim filed against the Republic of Guatemala.

Additionally, in March 2014, an indemnification provision for an uncertain tax position at TCAE that was provided for in the 2012 purchase agreement was reversed due to favorable final decision by the highest court in Guatemala, resulting in the income from operations amount shown in the table below.

Combined components of income from discontinued operations attributable to TECO Energy

The following table provides selected components of discontinued operations related to TECO Coal and TECO Guatemala:

Components of income from discontinued operations attributable to TECO Energy (millions)	2014	2013	2012
Revenues—TECO Coal	$443.6	$496.2	$608.9
Revenues—TECO Guatemala	0.0	0.0	114.2
Income (loss) from operations—TECO Coal	(13.9)	5.4	66.0

Income (loss) from operations—TECO Guatemala	4.4	(0.2)	27.7
Loss on impairment—TECO Coal	(115.9)	0.0	0.0
Loss on assets sold, including transaction costs—TECO Guatemala	0.0	0.0	(38.3)
Income (loss) from discontinued operations—TECO Coal	(129.8)	5.4	66.0
Income (loss) from discontinued operations—TECO Guatemala	4.4	(0.2)	(10.6)
Income (loss) from discontinued operations	(125.4)	5.2	55.4
Provision (benefit) for income taxes	(49.4)	(3.8)	39.4
Income (loss) from discontinued operations, net	(76.0)	9.0	16.0
Less: Income from discontinued operations attributable to noncontrolling interest	0.0	0.0	0.3
Income (loss) from discontinued operations attributable to TECO Energy, net	$(76.0)	$9.0	$15.7

20. Goodwill and Asset Impairments

In 2012, the company recorded impairment charges to write down TECO Guatemala's goodwill and long-lived asset balances to their implied fair values prior to selling TECO Guatemala and writing off the remaining balances. In 2014, the company recorded goodwill related to the acquisition of NMGI. Also in 2014, the company recorded impairment charges to write down TECO Coal's assets to their implied fair values based on a binding offer less estimated costs to sell (see Note 19 for further information on the SPA). None of these impairments had cash flow impacts. See the Consolidated Statements of Cash Flows Asset impairment line item. Further detail is provided below.

The following table presents the changes in the carrying amount of goodwill related to TECO Guatemala and NMGC for the years ended Dec. 31, 2014, 2013 and 2012.

(millions)	TPS GO	TPS SJI	Total TECO Guatemala	NMGC	Total
Balance as of Jan. 1, 2012	$ 3.1	$ 52.3	$ 55.4	$ 0.0	$ 55.4
Impairment losses, pretax	(3.1)	(12.1)	(15.2)	0.0	(15.2)
Goodwill written off upon sale, pretax	0.0	(40.2)	(40.2)	0.0	(40.2)
Balance as of Dec. 31, 2012	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Balance as of Dec. 31, 2013	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Acquisition of NMGC	0.0	0.0	0.0	408.3	408.3
Balance as of Dec. 31, 2014	$ 0.0	$ 0.0	$ 0.0	$ 408.3	$ 408.3

Under the accounting guidance for goodwill, goodwill is not subject to amortization. Rather, goodwill is subject to an annual assessment for impairment at the reporting unit level. Reporting units are generally determined at one level below the operating segment level; reporting units with similar characteristics are grouped for the purpose of determining the impairment, if any, of goodwill. TECO Energy reviews recorded goodwill at least annually during the fourth quarter for each reporting unit.

New Mexico Gas Company

At Dec. 31, 2014, the company had $408.3 million of goodwill on its balance sheet, which is reflected in the NMGC segment. The goodwill on the company's balance sheet related to the NMGC segment was recorded upon acquisition of NMGI on Sept. 2, 2014 (see Note 21).

The fair value for NMGC was determined using a weighted combination of a discounted cash flow analysis, a comparable transaction analysis, and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, rate case assumptions, utility sector market performance and transactions, projected operating and capital cash flows for NMGC's business and the fair value of debt. The company determined the fair value of NMGC supports the book value and related goodwill carrying amounts at Dec. 31, 2014, resulting in no impairment charge.

TECO Guatemala

The goodwill formerly on the company's balance sheet related to the TECO Guatemala segment and arose from the purchase of multiple entities as a result of the company's investments in the Alborada (held by TPS GO) and San José (held by TPS SJI) power plants. Since these reporting units were one level below the operating segment level, discrete cash flow information was available, and management regularly reviewed their operating results separately, these were the reporting unit level at which potential impairment was tested.

Prior to the sales in 2012 (see Note 19), goodwill balances for the TPS GO and TPS SJI reporting units were written down to their implied fair values calculated using the offers from SUR and REIN. Although these were binding quoted prices, the fair value measurements were considered Level 2 measurements since the market was not active as defined by accounting standards (i.e. transactions for these assets were too infrequent to provide pricing information on an ongoing basis). Prior to receiving the offers from REIN and SUR, the fair values of TPS GO's and TPS SJI's goodwill amounts were calculated using the discounted cash flows appropriate for the business model of each reporting unit. Discounted cash flows were formerly the best estimates of fair value of the reporting units, since neither a sale nor a similar transaction was readily observed in the marketplace for many years due to an inactive market.

The Impairment losses, pretax and Goodwill written off upon sale, pretax amounts in the goodwill table above are reflected in the Income (loss) from discontinued operations line item in the Consolidated Statements of Income and the Loss (gain) on sales of business/assets, pretax line item in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2012.

Prior to the sale of TGS, the company recorded a long-lived asset pretax impairment charge of $2.0 million. This amount is recorded in the Income (loss) from discontinued operations line item in the Consolidated Statements of Income and the Asset impairment line item in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2012. The fair value was calculated using the offer from REIN. Although it was a binding quoted price, the fair value measurement was considered a Level 2 measurement since the market was not active as defined by accounting standards (i.e. transactions for these assets are too infrequent to provide pricing information on an ongoing basis).

TECO Coal

In both 2012 and 2013, TECO Coal temporarily idled some of its mines due to the softened coal market. As a result, the company performed impairment analyses in each fourth quarter on the mining complexes with closed mines and the coal reserves. The company used an undiscounted cash flows approach in determining the recoverability amount of the assets in accordance with applicable accounting guidance. All assets were determined to have carrying values that were recoverable; therefore, no impairment charge was deemed necessary in 2012 and 2013. Additionally, the company performed sensitivity analyses for the effects of inflation and noted that if inflation affected costs more than revenues by one percent each year, all assets would still be recoverable.

On Sept. 29, 2014, the Board of Directors of TECO Energy authorized management to enter into negotiations for the sale of TECO Coal (see Note 19). As a result of the anticipated agreement price of $120 million, a pretax $98.4 million asset impairment charge related to the TECO Coal assets was recorded in the third quarter of 2014. On Feb. 5, 2015,the company announced that it had entered into a second amendment to the SPA that was signed in October 2014. The second amendment reduced the purchase price to $80 million. Based on this purchase price reduction and changes that occurred in the fourth quarter to TECO's investment in TECO Coal, an additional pretax impairment charge of $17.5 million was taken in the fourth quarter, which resulted in a total pretax impairment charge of $115.9 million for the year ended Dec. 31, 2014. These charges represent the write down to TECO Coal's implied fair value of the then-binding offer and the current SPA purchase price less estimated costs to sell. Although the offer used in the analysis was a binding offer and the SPA is a contracted price, the fair value measurements are considered a Level 2 measurements since the market is not active as defined by accounting standards (i.e. transactions for these assets are too infrequent to provide pricing information on an ongoing basis). The asset impairment charges are recorded in the Income (loss) from discontinued operations line item in the Consolidated Statements of Income and the Asset impairment line item in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2014.

21. Acquisition of New Mexico Gas Company

Description of Transaction

On Sept. 2, 2014, the company completed the acquisition contemplated by the SPA dated May 25, 2013 by and among the company, NMGI, and Continental Energy Systems LLC. As a result of that acquisition, the company acquired all of the capital stock of NMGI. NMGI is the parent company of NMGC. The aggregate purchase price was $950 million, which included the assumption of $200 million of senior secured notes at NMGC, plus certain working capital adjustments.

Description of NMGC

On the acquisition date, NMGC, with approximately 720 employees, served more than 513,000 customers, predominately residential, in New Mexico with the majority located in the Central Rio Grande Corridor region, which is one of the fastest growing regions in the state. The company served approximately 60 percent of the state's population with customers in 23 of New Mexico's 33 counties. Customers are served through a combination of approximately 1,600 miles of transmission pipeline and 10,000 miles of distribution lines.

Strategic Rationale for Acquisition

- A transformative transaction that immediately added more than 513,000 customers in a single state.
- Provides an opportunity for TECO Energy's experienced management team to share marketing expertise to a new and growing service territory, and for both companies to share best practices to support growth.
- Diversifies TECO Energy's operating footprint.
- Provides immediate to near-term shareholder and customer benefits through organic growth opportunities.

Acquisition-Related Regulatory Matters

NMGC is a rate-regulated natural gas utility subject to the regulation of the NMPRC, including with respect to its rates, service standards, accounting, securities issuances, construction of major new transmission and distribution facilities and other matters affecting, directly or indirectly, the provision of natural gas sales and transportation services to NMGC's customers.

In May 2014, TECO Energy reached a settlement with the New Mexico Industrial Energy Consumers (which represents large customers), the New Mexico Attorney General's office (which represents the New Mexico residential and small business customers) and the U.S. Department of Energy. As part of this settlement of the application for approval of the acquisition by the NMPRC, TECO Energy agreed, among other things, to:

- Freeze rates for NMGC customers until the end of 2017,
- credit NMGC customers with a $2 million rate credit to customer bills in the first year after the close of the transaction, which will increase to $4 million per year until NMGC's next rate case,
- cap job losses in New Mexico at 99 over three years, many of which will be through attrition,
- maintain the NMGC name and headquarters in Albuquerque,
- support new economic development opportunities designed to attract new businesses to New Mexico through maintaining good service and reasonable customer rates,
- maintain or increase NMGC's current level of community involvement and support, and
- own NMGC for at least 10 years.

On Aug. 13, 2014, the NMPRC approved the acquisition with the conditions set forth in the settlement agreements described above. The transaction closed on Sept. 2, 2014.

Purchase Price

The total consideration in the acquisition was as follows:

Consideration Transferred

(millions)	
Cash paid to seller	$530.1
Cash paid to settle long-term debt, including accrued interest and fees	219.9
Long-term debt assumed	200.0
Total consideration transferred, excluding cash and working capital adjustments	$950.0

Purchase Price Allocation

The majority of NMGI's assets acquired and liabilities assumed relate to deferred income taxes associated with its NOL. These were recorded in accordance with the applicable accounting guidance. Additionally, the company paid off the existing outstanding debt at NMGI and issued $200 million of new NMGI debt at closing. Since the refinancing took place at closing, face value approximated fair value.

The majority of NMGC's operations are subject to the rate-setting authority of the NMPRC and are accounted for pursuant to U.S. GAAP, including the accounting guidance for regulated operations. Rate-setting and cost recovery provisions currently in place for NMGC's regulated operations provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. Except for long-term debt, the ARO, derivatives, OPEB plans, and deferred taxes, fair values of tangible and intangible assets and liabilities subject to these rate-setting provisions approximate their carrying values. Accordingly, assets acquired and liabilities assumed and pro-forma financial information do not reflect any net adjustments related to these amounts. The difference between fair value and pre-merger carrying amounts for long-term debt, derivatives, and the OPEB plan for regulated operations were recorded as regulatory assets or liabilities.

The excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed was recognized as goodwill at the acquisition date. The goodwill reflects the value paid primarily for opportunities for growth, synergies and an improved risk profile. Goodwill resulting from the acquisition was allocated entirely to the NMGC segment. Goodwill of $146.1 million related to the formation of NMGC in 2009 is tax deductible. The incremental goodwill recognized as part of this transaction is not deductible for income tax purposes, and as such, no deferred taxes will be recorded related to this portion of the goodwill.

The valuations performed in the third quarter of 2014 to determine the fair value of the assets acquired and liabilities assumed were updated in the fourth quarter of 2014. The updates primarily related to property, plant and equipment that was written off and changes in the valuation of certain liabilities related to employee benefits. These updates increased the amount of goodwill acquired by approximately $6.5 million. Although the allocation of the purchase price may be modified up to one year from the date of the acquisition as more information is obtained about the fair value of assets acquired and liabilities assumed, we do not anticipate any material adjustments to the fair value assessments subsequent to Dec. 31, 2014.

The purchase price allocation of the acquisition of NMGI and NMGC is as follows:

Purchase Price Allocation (millions)	
Current assets [(a)]	$48.7
Property, plant and equipment	616.5
OPEB regulatory asset	6.4
Debt-related regulatory asset	23.9
Goodwill	408.3
Deferred tax assets	52.8
Other assets	29.3
Total assets	$1,185.9
Current liabilities	$(38.2)
Long-term debt fair value adjustment and interest assumed	(22.7)
Cost of removal regulatory liability	(100.6)
Deferred tax liabilities	(60.8)
OPEB liability	(9.8)
Deferred credits and other liabilities	(3.8)
Total liabilities	$(235.9)
Total purchase price allocation, excluding cash and working capital adjustments	$950.0

(a) Includes accounts receivables with fair value of $18.9 million, gross contract value of $19.6 million, and $0.7 million of contractual receivables not expected to be collected.

Impact of Acquisition

The impact of NMGI and NMGC on the company’s revenues in the Consolidated Statements of Operations for the year ended Dec. 31, 2014 was an increase of $137.5 million. The impact of NMGI and NMGC on the company’s net income in the Consolidated Statements of Operations for the year ended Dec. 31, 2014 was an increase of $8.2 million.

Pro Forma Impact of the Acquisition

The following unaudited pro forma financial information reflects the consolidated results of operations of the company and reflects the amortization of purchase accounting adjustments assuming the acquisition had taken place on Jan. 1, 2013. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of the company.

Pro forma earnings presented below include adjustments related to non-recurring acquisition consummation, integration and other costs incurred by the company during the period. After-tax non-recurring acquisition consummation, integration and other costs incurred by the company were $8.6 million and $6.2 million for the years ended Dec. 31, 2014 and 2013, respectively.

Pro Forma Impact of Acquisition	For year ending Dec. 31,	
(millions, except per share amounts)	2014	2013
Revenues	$2,806.6	$2,704.0
Net income from continuing operations	223.8	216.8
Basic and diluted EPS from continuing operations	0.96	0.93

Goodwill

Goodwill resulting from the acquisition was allocated entirely to the NMGC segment. The goodwill related to the formation of NMGC in 2009 in the amount of $146.1 million is tax deductible. The incremental goodwill recognized is not deductible for income tax purposes, and as such, no deferred taxes will be recorded related to this portion of the goodwill.

Transaction and Integration Costs

The following after-tax transaction and integration charges were recognized in connection with the acquisition and are included in the TECO Energy Consolidated Statement of Income for the year ended Dec. 31, 2014.

Transaction and Integration Costs (millions)	Total
Legal and other consultants	$8.0
Bridge loan costs	3.3
Severance and relocation costs	2.8
Other costs and tax benefit	(5.5)
Total accounting charges	$8.6

The company has an ongoing severance plan under which, in general, the longer a terminated employee worked prior to termination, the greater the amount of severance benefits. The company records a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the company measures the obligation and records the expense at its fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

In conjunction with the acquisition, in September 2014, TECO Energy and NMGC each offered a severance plan to certain eligible employees. Severance costs incurred were recorded primarily within Operation and maintenance other expense in the Consolidated Condensed Statements of Income. Cash payments under the severance plan began in the third quarter of 2014 and will continue through 2015. Substantially all cash payments under the plan are expected to be made by the end of 2017 resulting in the substantial completion of the acquisition integration plan. As of Dec. 31, 2014, the obligations associated with the severance benefits costs are $2.6 million.

22. Quarterly Data (unaudited)

Financial data by quarter is as follows:

(millions, except per share amounts)

Quarter ended	Dec. 31	Sept. 30	June 30	Mar. 31
2014				
Revenues	$695.5	$687.2	$605.7	$578.0
Income from operations	112.1	145.7	132.0	115.6
Net income from continuing operations	27.4	73.0	57.6	48.4
Net income	10.8	11.1	58.4	50.1
EPS—Basic				
Net income from continuing operations	$0.11	$0.32	$0.27	$0.22
Net income	0.04	0.04	0.27	0.23
EPS—Diluted				
Net income from continuing operations	$0.11	$0.32	$0.27	$0.22
Net income	0.04	0.04	0.27	0.23
Dividends paid per common share outstanding	$0.220	$0.220	$0.220	$0.220

Quarter ended	Dec. 31	Sept. 30	June 30	Mar. 31
2013				
Revenues	$562.2	$642.1	$607.5	$543.3
Income from operations	95.0	141.7	118.1	99.8
Net income from continuing operations	35.4	64.3	50.7	38.3
Net income	42.0	62.8	51.4	41.5
EPS—Basic				
Net income from continuing operations	$0.17	$0.30	$0.24	$0.17
Net income	0.20	0.29	0.24	0.19
EPS—Diluted				
Net income from continuing operations	$0.17	$0.30	$0.24	$0.17
Net income	0.20	0.29	0.24	0.19
Dividends paid per common share outstanding	$0.220	$0.220	$0.220	$0.220

Amounts shown include reclassifications to reflect discontinued operations as discussed in Note 19.

23. Subsequent Events

Tampa Electric Company Accounts Receivable Facility

On Feb. 3, 2015, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 13 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A. as Program Agent. The amendment extends the maturity date to Apr. 14, 2015.

Amendment to TECO Coal SPA

On Feb. 5, 2015, TECO Diversified entered into Amendment No. 2 (the Amendment) to the SPA dated as of Oct. 17, 2014, as amended, with Cambrian Coal Corporation. As disclosed in Note 19, the SPA related to the sale of all of the ownership interest in TECO Coal to Cambrian Coal Corporation, and was subject to termination by either party if specified closing conditions, including the purchaser's obtaining financing in order to pay a portion of the purchase price, were not met by Feb. 20, 2015 (Outside Date). The Amendment (i) reduces the purchase price to $80 million plus any cash on hand as of the closing, subject to customary post-closing adjustments, plus contingent payments of up to $60 million that may be paid between 2015 and 2019 depending on specified coal benchmark prices and (ii) extends the Outside Date by providing that the SPA, as amended, is subject to termination by either party if the specified closing conditions (including the purchaser's obtaining financing) are not met by Mar. 13, 2015.

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TAMPA ELECTRIC COMPANY

Report of Independent Registered Certified Public Accounting Firm

To the Board of Directors and Shareholder of Tampa Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Tampa Electric Company and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida

February 27, 2015

TAMPA ELECTRIC COMPANY

Consolidated Balance Sheets

Assets (millions)	Dec. 31, 2014	Dec. 31, 2013
Property, plant and equipment		
Utility plant in service		
Electric	$7,094.8	$6,934.0
Gas	1,308.9	1,249.5
Construction work in progress	624.2	385.3
Utility plant in service, at original costs	9,027.9	8,568.8
Accumulated depreciation	(2,633.8)	(2,562.6)
	6,394.1	6,006.2
Other property	8.6	8.3
Total property, plant and equipment, net	6,402.7	6,014.5
Current assets		
Cash and cash equivalents	10.4	9.8
Receivables, less allowance for uncollectibles of $1.4 and $2.0 at Dec. 31, 2014 and 2013, respectively	227.2	227.6
Inventories, at average cost		
Fuel	85.2	93.7
Materials and supplies	72.2	76.8
Regulatory assets	52.1	34.3
Derivative assets	0.0	9.5
Taxes receivable from affiliate	43.3	54.9
Deferred income taxes	24.8	29.4
Prepayments and other current assets	17.4	12.5
Total current assets	532.6	548.5
Deferred debits		
Unamortized debt expense	16.8	14.8
Regulatory assets	319.6	293.1
Derivative assets	0.0	0.3
Other	2.6	4.6
Total deferred debits	339.0	312.8
Total assets	$7,274.3	$6,875.8

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY

Consolidated Balance Sheets—continued

Liabilities and Capital (millions)	Dec. 31, 2014	Dec. 31, 2013
Capitalization		
Common stock	$2,130.4	$2,030.4
Accumulated other comprehensive loss	(7.1)	(7.8)
Retained earnings	305.8	308.1
Total capital	2,429.1	2,330.7
Long-term debt, less amount due within one year	2,013.8	1,797.5
Total capital	4,442.9	4,128.2
Current liabilities		
Long-term debt due within one year	83.3	83.3
Notes payable	58.0	84.0
Accounts payable	242.3	226.0
Customer deposits	170.4	164.5
Regulatory liabilities	54.7	85.8
Derivative liabilities	36.6	0.0
Interest accrued	17.0	16.4
Taxes accrued	12.4	12.2
Other	10.0	12.0
Total current liabilities	684.7	684.2
Deferred credits		
Deferred income taxes	1,209.1	1,114.3
Investment tax credits	9.0	9.4
Derivative liabilities	6.1	0.2
Regulatory liabilities	623.4	631.4
Other	299.1	308.1
Total deferred credits	2,146.7	2,063.4
Commitments and Contingencies (see Note 9)		
Total liabilities and capital	$7,274.3	$6,875.8

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY

Consolidated Statements of Income and Comprehensive Income

(millions) For the years ended Dec. 31,	2014	2013	2012
Revenues			
Electric	$2,020.5	$1,950.1	$1,981.0
Gas	398.5	392.7	397.0
Total revenues	2,419.0	2,342.8	2,378.0
Expenses			
Regulated operations & maintenance			
Fuel	692.3	680.2	694.7
Purchased power	71.4	64.7	105.3
Cost of natural gas sold	137.0	142.6	155.8
Other	518.4	523.6	462.0
Depreciation and amortization	302.6	290.3	288.2
Taxes, other than income	189.8	183.1	184.0
Total expenses	1,911.5	1,884.5	1,890.0
Income from operations	507.5	458.3	488.0
Other income			
Allowance for other funds used during construction	10.5	6.3	2.6
Other income, net	4.8	5.1	4.1
Total other income	15.3	11.4	6.7
Interest charges			
Interest on long-term debt	107.5	105.0	119.6
Other interest	4.2	3.9	7.7
Allowance for borrowed funds used during construction	(5.1)	(3.6)	(1.5)
Total interest charges	106.6	105.3	125.8
Income before provision for income taxes	416.2	364.4	368.9
Provision for income taxes	155.9	138.8	141.7
Net income	260.3	225.6	227.2
Other comprehensive income, net of tax			
Net unrealized gain (loss) on cash flow hedges	0.7	0.9	(4.1)
Total other comprehensive income (loss), net of tax	0.7	0.9	(4.1)
Comprehensive income	$261.0	$226.5	$223.1

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY

Consolidated Statements of Cash Flows

(millions) For the years ended Dec. 31,	2014	2013	2012
Cash flows from operating activities			
Net income	$260.3	$225.6	$227.2
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	302.6	290.3	288.2
Deferred income taxes and investment tax credits	92.2	118.1	155.6
Allowance for other funds used during construction	(10.5)	(6.3)	(2.6)
Deferred recovery clauses	(16.2)	(6.2)	(8.9)
Receivables, less allowance for uncollectibles	0.4	(13.8)	1.6
Inventories	13.1	(9.0)	4.1
Taxes accrued	11.8	(34.3)	(5.7)
Interest accrued	0.6	(0.9)	(8.3)
Accounts payable	5.9	34.8	12.4
Other	(13.0)	(2.8)	4.0
Cash flows from operating activities	647.2	595.5	667.6
Cash flows from investing activities			
Capital expenditures	(681.5)	(507.6)	(459.0)
Allowance for other funds used during construction	10.5	6.3	2.6
Net proceeds from sale of assets	0.0	0.1	0.3
Cash flows used in investing activities	(671.0)	(501.2)	(456.1)
Cash flows from financing activities			
Common stock	100.0	60.0	118.0
Proceeds from long-term debt issuance	296.3	0.0	538.1
Repayment of long-term debt/Purchase in lieu of redemption	(83.3)	(51.6)	(608.0)
Net (decrease) increase in short-term debt	(26.0)	84.0	0.0
Dividends paid	(262.6)	(222.1)	(228.3)
Cash flows from/(used in) financing activities	24.4	(129.7)	(180.2)
Net increase (decrease) in cash and cash equivalents	0.6	(35.4)	31.3
Cash and cash equivalents at beginning of the year	9.8	45.2	13.9
Cash and cash equivalents at end of the year	$10.4	$9.8	$45.2
Supplemental disclosure of cash flow information			
Cash paid (received) during the year for:			
Interest	$102.5	$102.4	$128.1
Income taxes	$52.6	$56.4	$(9.7)
Supplemental disclosure of cash flow information			
Change in accrued capital expenditures	$14.3	$4.7	$(13.9)

The accompanying notes are an integral part of the consolidated financial statements.

131

TAMPA ELECTRIC COMPANY

Consolidated Statements of Retained Earnings

(millions) For the years ended Dec. 31,	2014	2013	2012
Balance, beginning of year	$308.1	$304.6	$305.7
Add: Net income	260.3	225.6	227.2
	568.4	530.2	532.9
Deduct: Cash dividends on capital stock—common	262.6	222.1	228.3
Balance, end of year	$305.8	$308.1	$304.6

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY

Consolidated Statements of Capitalization

(millions, except share amounts)	Current Redemption Price	Capital Stock Outstanding Dec. 31, Shares	Amount	Cash Dividends Paid [1] Per Share	Amount
Common stock - without par value					
25 million shares authorized					
2014 [3][4]	N/A	10	$ 2,130.4	(2)	$ 262.6
2013 [3][4]	N/A	10	$ 2,030.4	(2)	$ 222.1

Preferred stock – $100 par value

1.5 million shares authorized, none outstanding.

Preferred stock – no par

2.5 million shares authorized, none outstanding.

Preference stock – no par

2.5 million shares authorized, none outstanding.

(1) Quarterly dividends paid on Feb. 28, May 28, Aug. 28 and Nov. 28 during 2014.
Quarterly dividends paid on Feb. 28, May 28, Aug. 28 and Nov. 27 during 2013.

(2) Not meaningful.
(3) No issue expense.
(4) TECO Energy made equity contributions to TEC of $100.0 million in 2014 and $60.0 million in 2013.
The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY

Consolidated Statements of Capitalization – continued

At Dec. 31, 2014 and 2013, TEC had the following long-term debt outstanding:

Long-Term Debt (millions)		Due	2014	2013
Tampa Electric	Installment contracts payable [1] :			
	5.65% Refunding bonds	2018	54.2	54.2
	Variable rate bonds repurchased in 2008 [2]	2020	0.0	0.0
	5.15% Refunding bonds repurchased in 2013 [3]	2025	0.0	0.0
	1.5% Term rate bonds repurchased in 2011 [4]	2030	0.0	0.0
	5.0% Refunding bonds repurchased in 2012 [5]	2034	0.0	0.0
	Notes [6][7] : 6.25%	2014-2016	166.7	250.0
	6.10%	2018	200.0	200.0
	5.40%	2021	231.7	231.7
	2.60%	2022	225.0	225.0
	6.55%	2036	250.0	250.0
	6.15%	2037	190.0	190.0
	4.10%	2042	250.0	250.0
	4.35%	2044	290.0	0.0
	Total long-term debt of Tampa Electric		1,857.6	1,650.9
PGS	Notes [6][7] : 6.10%	2018	50.0	50.0
	5.40%	2021	46.7	46.7
	2.60%	2022	25.0	25.0
	6.15%	2037	60.0	60.0
	4.10%	2042	50.0	50.0
	4.35%	2044	10.0	0.0
	Total long-term debt of PGS		241.7	231.7
Total long-term debt of TEC			2,099.3	1,882.6
Unamortized debt discount, net			(2.2)	(1.8)
Total carrying amount of long-term debt			2,097.1	1,880.8
Less amount due within one year			83.3	83.3
Total long-term debt			$2,013.8	$1,797.5

(1) Tax-exempt securities.
(2) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by TEC. These held variable rate bonds have a par amount of $20.0 million due in 2020.
(3) In September 2013 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $51.6 million due in 2025.
(4) In March 2011 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $75.0 million due in 2030.
(5) In March 2012 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $86.0 million due in 2034.
(6) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(7) These long-term debt agreements contain various restrictive covenants.

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY

Consolidated Statements of Capitalization—continued

At Dec. 31, 2014, total long-term debt had a carrying amount of $2,097.1 million and an estimated fair market value of $2,372.2 million. At Dec. 31, 2013, total long-term debt had a carrying amount of $1,880.8 million and an estimated fair market value of $2,042.0 million. TEC uses the market approach in determining fair value. The majority of the outstanding debt is valued using real-time financial market data obtained from Bloomberg Professional Service. The remaining securities are valued using prices obtained from the Municipal Securities Rulemaking Board and by applying estimated credit spreads obtained from a third party to the par value of the security. All debt securities are Level 2 instruments.

A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture, and Tampa Electric could cause the lien associated with this indenture to be released at any time. Gross maturities and annual sinking fund requirements of long-term debt for the years 2015 through 2019 and thereafter are as follows:

Long-Term Debt Maturities

As of Dec. 31, 2014 (millions)	2015	2016	2017	2018	2019	Thereafter	Total Long-Term Debt
Tampa Electric	$83.3	$83.4	$0.0	$254.2	$0.0	$ 1,436.7	$ 1,857.6
PGS	0.0	0.0	0.0	50.0	0.0	191.7	241.7
Total long-term debt maturities	$83.3	$83.4	$0.0	$304.2	$0.0	$ 1,628.4	$ 2,099.3

The accompanying notes are an integral part of the consolidated financial statements.

TAMPA ELECTRIC COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

TEC has two business segments. Its Tampa Electric division provides retail electric services in West Central Florida, and PGS, the gas division of TEC, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida. TEC’s significant accounting policies are as follows:

Basis of Accounting

TEC maintains its accounts in accordance with recognized policies prescribed or permitted by the FPSC and the FERC. These policies conform with GAAP in all material respects.

The impact of the accounting guidance for the effects of certain types of regulation has been minimal in the company’s experience, but when cost recovery is ordered over a period longer than a fiscal year, costs are recognized in the period that the regulatory agency recognizes them in accordance with this guidance.

TEC’s retail and wholesale businesses are regulated by the FPSC and related FERC, respectively. Prices allowed by both agencies are generally based on recovery of prudent costs incurred plus a reasonable return on invested capital.

Principles of Consolidation

TEC is a wholly-owned subsidiary of TECO Energy, Inc., and is comprised of the Electric division, generally referred to as Tampa Electric, and the Natural Gas division, PGS. Intercompany balances and intercompany transactions have been eliminated in consolidation. The use of estimates is inherent in the preparation of financial statements in accordance with GAAP. Actual results could differ from these estimates.

For entities that are determined to meet the definition of a VIE, TEC obtains information, where possible, to determine if it is the primary beneficiary of the VIE. If TEC is determined to be the primary beneficiary, then the VIE is consolidated and a minority interest is recognized for any other third-party interests. If TEC is not the primary beneficiary, then the VIE is accounted for using the equity or cost method of accounting. In certain circumstances this can result in TEC consolidating entities in which it has less than a 50% equity investment and deconsolidating entities in which it has a majority equity interest (see Note 15).

Planned Major Maintenance

Tampa Electric and PGS expense major maintenance costs as incurred. Concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with FPSC and FERC regulations.

Cash Equivalents

Cash equivalents are highly liquid, high-quality investments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

Depreciation

Tampa Electric and PGS compute depreciation and amortization for electric generation, electric transmission and distribution, gas distribution and general plant facilities using the following methods:

- the group remaining life method, approved by the FPSC, is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property;
- the amortizable life method, approved by the FPSC, is applied to the net book value to date over the remaining life of those assets not classified as depreciable property above.

The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 3.7% for 2014, 3.7% for 2013 and 3.8% for 2012. Construction work in progress is not depreciated until the asset is completed or placed in service. Total depreciation expense for the years ended Dec. 31, 2014, 2013 and 2012 was $295.8 million, $284.2 million and $275.1 million, respectively.

On Sept. 11, 2013, the FPSC unanimously voted to approve a stipulation and settlement agreement between TEC and all of the intervenors in its Tampa Electric division base rate proceeding. As a result, Tampa Electric began using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013.

Cash Flows Related to Derivatives and Hedging Activities

TEC classifies cash inflows and outflows related to derivative and hedging instruments in the appropriate cash flow sections associated with the item being hedged. For natural gas, the cash inflows and outflows are included in the operating section of the Consolidated Statements of Cash Flows.

Allowance for Funds Used During Construction

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The FPSC approved rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 8.16% for May 2009 through December 2013. In March 2014, the rate was revised to 6.46% effective Jan. 1, 2014. Total AFUDC for the years ended Dec. 31, 2014, 2013 and 2012 was $15.6 million, $9.9 million and $4.1 million, respectively.

Deferred Income Taxes

TEC uses the asset and liability method in the measurement of deferred income taxes. Under the asset and liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

Investment Tax Credits

ITCs have been recorded as deferred credits and are being amortized as reductions to income tax expense over the service lives of the related property.

Inventory

TEC values materials, supplies and fossil fuel inventory (coal, oil and natural gas) using a weighted-average cost method. These materials, supplies and fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered with a normal profit upon sale in the ordinary course of business.

Revenue Recognition

TEC recognizes revenues consistent with accounting standards for revenue recognition. Except as discussed below, TEC recognizes revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer.

The regulated utilities' (Tampa Electric and PGS) retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. See Note 3 for a discussion of significant regulatory matters and the applicability of the accounting guidance for certain types of regulation to the company.

Revenues and Cost Recovery

Revenues include amounts resulting from cost-recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for PGS. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over- or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as regulatory liabilities, and under-recoveries of costs are recorded as regulatory assets.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. The regulated utilities accrue base revenues for services rendered but unbilled to provide for a closer matching of revenues and expenses (see Note 3). As of Dec. 31, 2014 and 2013, unbilled revenues of $49.3 million and $46.7 million, respectively, are included in the “Receivables” line item on TEC’s Consolidated Balance Sheets.

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. Tampa Electric purchased power from non-TECO Energy affiliates at a cost of $71.4 million, $64.7 million and $105.3 million, for the years ended Dec. 31, 2014, 2013 and 2012, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost-recovery clause.

Accounting for Excise Taxes, Franchise Fees and Gross Receipts

TEC is allowed to recover certain costs on a dollar-per-dollar basis incurred from customers through prices approved by the FPSC. The amounts included in customers’ bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in “Taxes, other than income”. These amounts totaled $113.9 million, $108.5 million and $111.5 million for the years ended Dec. 31, 2014, 2013 and 2012, respectively. Excise taxes paid by the regulated utilities are not material and are expensed as incurred.

2. New Accounting Pronouncements

Extraordinary and Unusual Items

In January 2015, the FASB issued guidance to remove the concept of extraordinary items from U.S. GAAP. Therefore, events or transactions that are of an unusual nature and occur infrequently will no longer be allowed to be separately disclosed, net of tax, in the income statement after income from continuing operations. The standard is effective for the company beginning Jan. 1, 2016. TEC does not expect a significant impact from the adoption of this guidance.

Revenue from Contracts with Customers

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The standard is principle-based and provides a five-step model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This guidance is effective for the company beginning in 2017 and allows for either full retrospective adoption or modified retrospective adoption. TEC is currently evaluating the impact of the adoption of this guidance on its financial statements but does not expect the impact to be significant.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

In April 2014, the FASB issued guidance regarding changing the criteria for reporting discontinued operations. Under the new guidance, which is intended to enhance convergence of the FASB’s and the IASB’s reporting requirements for discontinued operations, a disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity’s operations and financial results. This standard is effective for TEC beginning in 2015.

Going Concern

In August 2014, the FASB issued guidance defining management’s responsibility to decide whether there is substantial doubt about an organization’s ability to continue as a going concern and the related footnote disclosures required. This guidance is effective for TEC beginning in 2017. TEC does not expect any significant impact from the adoption of this guidance on its financial statements.

3. Regulatory

Tampa Electric’s retail business and PGS are regulated by the FPSC. Tampa Electric is also subject to regulation by the FERC under PUHCA 2005. The operations of PGS are regulated by the FPSC separately from the operations of Tampa Electric. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC sets rates at a level that allows utilities such as Tampa Electric and PGS to collect total revenues (revenue requirements) equal to their cost of providing service, plus a reasonable return on invested capital.

Base Rates-Tampa Electric

Tampa Electric's results for the first ten months of 2013 and 2012, reflect base rates established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE midpoint of 11.25%, 54.0% equity in the capital structure and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for CTs and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

Tampa Electric's results for 2014 and the last two months of 2013 reflect the results of a Stipulation and Settlement Agreement entered on Sept. 6, 2013, between TEC and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric's 2013 base rate proceeding. On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement.

This agreement provided for the following revenue increases: $57.5 million effective Nov. 1, 2013, an additional $7.5 million effective Nov. 1, 2014, an additional $5.0 million effective Nov. 1, 2015, and an additional $110.0 million effective Jan. 1, 2017 or the date that the expansion of TEC's Polk Power Station goes into service, whichever is later. The agreement provides that Tampa Electric's allowed regulatory ROE would be a mid-point of 10.25% with a range of plus or minus 1%, with a potential increase to 10.50% if U.S. Treasury bond yields exceed a specified threshold. The agreement provides that Tampa Electric cannot file for additional rate increases until 2017 (to be effective no sooner than Jan. 1, 2018), unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE is increased as described above) any party to the agreement other than TEC could seek a review of Tampa Electric's base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital and Tampa Electric began using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013. Effective Nov. 1, 2013, Tampa Electric ceased accruing $8.0 million annually to the FERC-authorized and FPSC-approved self-insured storm damage reserve.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services and accounting practices.

Storm Damage Cost Recovery

Prior to the above mentioned stipulation and settlement agreement, Tampa Electric was accruing $8.0 million annually to a FERC-authorized and FPSC-approved self-insured storm damage reserve. This reserve was created after Florida's IOUs were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Effective Nov. 1, 2013, Tampa Electric ceased accruing for this storm damage reserve as a result of the 2013 rate case settlement. However, in the event of a named storm that results in damage to its system, Tampa Electric can petition the FPSC to seek recovery of those costs over a 12-month period or longer as determined by the FPSC, as well as replenish its reserve to $56.1 million; the level it was as of Oct. 31, 2013. Tampa Electric's storm reserve remained $56.1 million at both Dec. 31, 2014 and 2013.

Base Rates-PGS

PGS's base rates were established in May 2009 and reflect an ROE of 10.75%, which is the middle of a range between 9.75% to 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital, on an allowed rate base of $560.8 million.

Regulatory Assets and Liabilities

Tampa Electric and PGS apply the accounting standards for regulated operations. Areas of applicability include: deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost-recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs; and the deferral of costs as regulatory assets to the period in which the regulatory agency recognizes them, when cost recovery is ordered over a period longer than a fiscal year.

Details of the regulatory assets and liabilities as of Dec. 31, 2014 and 2013 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	Dec. 31, 2014	Dec. 31, 2013
Regulatory assets:		
Regulatory tax asset [(1)]	$ 69.2	$ 67.4
Other:		
Cost-recovery clauses	43.6	6.1
Postretirement benefit asset [(2)]	187.8	182.7
Deferred bond refinancing costs [(3)]	7.2	8.0
Environmental remediation	53.1	51.4
Competitive rate adjustment	2.8	4.1
Other	8.0	7.7
Total other regulatory assets	302.5	260.0
Total regulatory assets	371.7	327.4
Less: Current portion	52.1	34.3
Long-term regulatory assets	$ 319.6	$ 293.1
Regulatory liabilities:		
Regulatory tax liability [(1)]	$ 5.1	$ 9.8
Other:		
Cost-recovery clauses	23.5	54.5
Transmission and delivery storm reserve	56.1	56.1
Deferred gain on property sales [(4)]	0.8	2.0
Provision for stipulation and other	1.1	0.8
Accumulated reserve - cost of removal	591.5	594.0
Total other regulatory liabilities	673.0	707.4
Total regulatory liabilities	678.1	717.2
Less: Current portion	54.7	85.8
Long-term regulatory liabilities	$ 623.4	$ 631.4

(1) Primarily related to plant life and derivative positions.
(2) Amortized over the remaining service life of plan participants.
(3) Amortized over the term of the related debt instruments.
(4) Amortized over a 5-year period with various ending dates.

All regulatory assets are recovered through the regulatory process. The following table further details the regulatory assets and the related recovery periods:

Regulatory assets

(millions)	Dec. 31, 2014	Dec. 31, 2013
Clause recoverable [(1)]	$ 46.4	$ 10.2
Components of rate base [(2)]	191.0	185.6
Regulatory tax assets [(3)]	69.2	67.4
Capital structure and other [(3)]	65.1	64.2
Total	$ 371.7	$ 327.4

(1) To be recovered through cost-recovery mechanisms approved by the FPSC on a dollar-for-dollar basis in the next year.

(2) Primarily reflects allowed working capital, which is included in rate base and earns a rate of return as permitted by the FPSC.

(3) "Regulatory tax assets" and "Capital structure and other" regulatory assets, including environmental remediation, have a recoverable period longer than a fiscal year and are recognized over the period authorized by the regulatory agency. Also included are unamortized loan costs, which are amortized over the life of the related debt instruments. See footnotes 1 and 2 in the prior table for additional information.

4. Income Taxes

Income Tax Expense

TEC is included in the filing of a consolidated federal income tax return with TECO Energy and its affiliates. TEC's income tax expense is based upon a separate return computation. For the three years presented, TEC's effective tax rate differs from the statutory rate principally due to state income taxes.

Income tax expense consists of the following components:

Income Tax Expense (Benefit)

(millions)			
For the year ending Dec. 31,	2014	2013	2012
Current income taxes			
Federal	$54.8	$19.4	$(19.5)
State	8.9	1.3	5.6
Deferred income taxes			
Federal	79.0	99.8	141.2
State	13.5	18.6	14.7
Amortization of investment tax credits	(0.3)	(0.3)	(0.3)
Total income tax expense	$155.9	$138.8	$141.7

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes as follows:

Effective Income Tax Rate

(millions)			
For the years ended Dec. 31,	2014	2013	2012
Income tax expense at the federal statutory rate of 35%	$145.7	$127.5	$129.1
Increase (decrease) due to			
State income tax, net of federal income tax	14.5	13.0	13.2
Other	(4.3)	(1.7)	(0.6)
Total income tax expense on consolidated statements of income	$155.9	$138.8	$141.7
Income tax expense as a percent of income from continuing operations, before income taxes	37.5 %	38.1 %	38.4 %

Deferred Income Taxes

Deferred taxes result from temporary differences in the recognition of certain liabilities or assets for tax and financial reporting purposes. The principal components of TEC's deferred tax assets and liabilities recognized in the balance sheet are as follows:

(millions)		
As of Dec. 31,	2014	2013
Deferred tax liabilities [(1)]		
Property related	$1,328.8	$1,166.4
Pension and postretirement benefits	72.5	70.5
Pension	51.8	43.2
Total deferred tax liabilities	1,453.1	1,280.1
Deferred tax assets [(1)]		
Loss and credit carryforwards	77.7	4.8
Medical benefits	51.0	50.9
Insurance reserves	29.0	29.1
Pension and postretirement benefits	72.5	70.5
Capitalized energy conservation assistance costs	20.3	19.6
Other	18.3	20.3
Total deferred tax assets	268.8	195.2
Total deferred tax liability, net	1,184.3	1,084.9
Less: Current portion of deferred tax asset	(24.8)	(29.4)
Long-term portion of deferred tax liability, net	$1,209.1	$1,114.3

(1) Certain property related assets and liabilities have been netted.

At Dec. 31, 2014, TEC had cumulative unused federal and Florida NOLs for income tax purposes of $194.1 million and $268.5 million, respectively, expiring in 2033.

Unrecognized Tax Benefits

TEC accounts for uncertain tax positions as required by FASB accounting guidance. This guidance addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under the guidance, TEC may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The guidance also provides standards on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

As of Dec. 31, 2014 and 2013, TEC did not have a liability for unrecognized tax benefits. Based on current information, TEC does not anticipate that this will change materially in 2015. As of Dec. 31, 2014, TEC does not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

The IRS concluded its examination of TECO Energy's 2013 consolidated federal income tax return in January 2015. The U.S. federal statute of limitations remains open for the year 2011 and onward. Years 2014 and 2015 are currently under examination by the IRS under its Compliance Assurance Program. Florida's statute of limitations is three years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by Florida's tax authorities include 2005 and forward as a result of TECO Energy's consolidated Florida net operating loss still being utilized. TEC does not expect the settlement of audit examinations to significantly change the total amount of unrecognized tax benefits within the next 12 months.

5. Employee Postretirement Benefits

Pension Benefits

TEC is a participant in the comprehensive retirement plans of TECO Energy, including a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on the employees’ age, years of service and final average earnings. Where appropriate and reasonably determinable, the portion of expenses, income, gains or losses allocable to TEC are presented. Otherwise, such amounts presented reflect the amount allocable to all participants of the TECO Energy retirement plans.

The Pension Protection Act became effective Jan. 1, 2008 and requires companies to, among other things, maintain certain defined minimum funding thresholds (or face plan benefit restrictions), pay higher premiums to the PBGC if they sponsor defined benefit plans, amend plan documents and provide additional plan disclosures in regulatory filings and to plan participants.

WRERA was signed into law on Dec. 23, 2008. WRERA grants plan sponsors relief from certain funding requirements and benefits restrictions, and also provides some technical corrections to the Pension Protection Act. There are two primary provisions that impact funding results for TECO Energy. First, for plans funded less than 100%, required shortfall contributions will be based on a percentage of the funding target until 2013, rather than the funding target of 100%. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging subject to certain limitations in the determination of funding requirements. TECO Energy utilizes asset smoothing in determining funding requirements.

In August 2014, the President signed into law HAFTA, which modified MAP-21. HAFTA and MAP-21 provide funding relief for pension plan sponsors by stabilizing discount rates used in calculating the required minimum pension contributions and increasing PBGC premium rates to be paid by plan sponsors. TECO Energy expects the required minimum pension contributions to be lower than the levels previously projected; however, TECO Energy plans on funding at levels above the required minimum pension contributions under HAFTA and MAP-21.

The qualified pension plan’s actuarial value of assets, including credit balance, was 110.8% of the Pension Protection Act funded target as of Jan. 1, 2014 and is estimated at 115.9% of the Pension Protection Act funded target as of Jan. 1, 2015.

Amounts disclosed for pension benefits in the following tables and discussion also include the unfunded obligations for the SERP. This is a non-qualified, non-contributory defined benefit retirement plan available to certain members of senior management.

Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits (Other Benefits) for most employees retiring after age 50 meeting certain service requirements. Where appropriate and reasonably determinable, the portion of expenses, income, gains or losses allocable to TEC are presented. Otherwise, such amounts presented reflect the amount allocable to all participants of the TECO Energy postretirement health care and life insurance plans. Postretirement benefit levels are substantially unrelated to salary. TECO Energy reserves the right to terminate or modify the plans in whole or in part at any time.

MMA added prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy’s current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan are at least “actuarially equivalent” to the standard drug benefits that are offered under Medicare Part D.

The FASB issued accounting guidance and disclosure requirements related to the MMA. The guidance requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

In March 2010, the Patient Protection and Affordable Care Act and a companion bill, the Health Care and Education Reconciliation Act, collectively referred to as the Health Care Reform Acts, were signed into law. Among other things, both acts reduced the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, TEC reduced its deferred tax asset and recorded a corresponding regulatory asset in 2010. This amount was trued up in 2013. TEC is amortizing the regulatory asset over the remaining average service life of 12 years. Additionally, the Health Care Reform Acts contain other provisions that may impact TECO Energy's obligation for retiree medical benefits. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase its PBO. TECO Energy will continue to monitor and assess the impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

Effective Jan. 1, 2013, the company decided to implement an EGWP for its post-65 retiree prescription drug plan. The EGWP is a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduces net periodic benefit cost by taking advantage of rebate and discount enhancements provided under the Health Care Reform Acts, which are greater than the subsidy payments previously received by the company under Medicare Part D for its post-65 retiree prescription drug plan.

Obligations and Funded Status

TEC recognizes in its statement of financial position the over-funded or under-funded status of its postretirement benefit plans. This status is measured as the difference between the fair value of plan assets and the PBO in the case of its defined benefit plan, or the APBO in the case of its other postretirement benefit plan. Changes in the funded status are reflected, net of estimated tax benefits, in benefit liabilities and regulatory assets. The results of operations are not impacted. Below is the detail of the change in benefit obligations, change in plan assets, unfunded liability and amounts recognized in TECO Energy's Consolidated Balance Sheets for 2014 and 2013.

TECO Energy	Pension Benefits		Other Benefits	
Obligations and Funded Status (millions)	2014	2013	2014	2013
Change in benefit obligation				
Net benefit obligation at beginning of year	$666.0	$715.0	$208.1	$230.3
Service cost	18.3	18.2	2.5	2.5
Interest cost	32.0	28.9	10.8	9.3
Plan participants' contributions	0.0	0.0	2.8	2.9
Plan amendments	0.0	0.0	(23.2)	0.0
Actuarial loss (gain)	48.3	(50.4)	1.5	(22.1)
Gross benefits paid	(39.9)	(43.1)	(16.0)	(15.0)
Transfer in due to the effect of business combination	0.0	0.0	26.7	0.0
Plan curtailment	4.0	0.0	(11.7)	0.0
Special termination benefit	0.2	0.0	0.0	0.0
Settlements	0.0	(2.6)	0.0	0.0
Federal subsidy on benefits paid	n/a	n/a	0.0	0.2
Net benefit obligation at end of year	$728.9	$666.0	$201.5	$208.1

Change in plan assets				
Fair value of plan assets at beginning of year	$593.0	$529.1	$0.0	$0.0
Actual return on plan assets	46.4	63.7	0.1	0.0
Employer contributions	47.5	44.6	(1.0)	11.9
Employer direct benefit payments	1.0	1.3	16.0	
Plan participants' contributions	0.0	0.0	2.8	2.9
Transfer in due to acquisition	0.0	0.0	16.9	0.0
Settlements	0.0	(2.6)	0.0	0.0
Net benefits paid	(39.9)	(43.1)	(16.0)	(14.8)
Fair value of plan assets at end of year	$648.0	$593.0	$18.8	$0.0

Funded status				
Fair value of plan assets (1)	$648.0	$593.0	$18.8	$0.0
Less: Benefit obligation (PBO/APBO)	728.9	666.0	201.5	208.1
Funded status at end of year	(80.9)	(73.0)	(182.7)	(208.1)
Unrecognized costs in regulated asset acquired in business combination	0.0	0.0	6.4	0.0
Unrecognized net actuarial loss	203.7	173.1	9.6	19.7
Unrecognized prior service (benefit) cost	0.0	(0.4)	(24.0)	(0.7)
Net amount required to be recognized at end of year	$122.8	$99.7	$(190.7)	$(189.1)

Amounts recognized in balance sheet				
Regulatory assets	$167.4	$139.6	$26.6	$43.2
Accrued benefit costs and other current liabilities	(4.9)	(3.3)	(10.7)	(13.3)
Deferred credits and other liabilities	(76.0)	(69.7)	(172.0)	(194.8)
Accumulated other comprehensive loss (income), pretax	36.3	33.1	(34.6)	(24.2)
Net amount recognized at end of year	$122.8	$99.7	$(190.7)	$(189.1)

(1) The MRV of plan assets is used as the basis for calculating the EROA component of periodic pension expense. MRV reflects the fair value of plan assets adjusted for experience gains and losses (i.e. the differences between actual investment returns and expected returns) spread over five years.

Tampa Electric Company	Pension Benefits		Other Benefits	
Amounts recognized in balance sheet (millions)	2014	2013	2014	2013
Regulatory assets	$167.4	$139.6	$20.4	$43.2
Accrued benefit costs and other current liabilities	(0.6)	(0.9)	(9.1)	(10.8)
Deferred credits and other liabilities	(53.5)	(50.1)	(137.1)	(158.3)
	$113.3	$88.6	$(125.8)	$(125.9)

The accumulated benefit obligation for TECO Energy Consolidated defined benefit pension plans was $685.0 million at Dec. 31, 2014 and $624.1 million at Dec. 31, 2013. The projected benefit obligation for the other postretirement benefits plan was $201.5 million at Dec. 31, 2014 and $208.1 million at Dec. 31, 2013.

Assumptions used to determine benefit obligations at Dec. 31:

	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
Discount rate	4.258%	5.118%	4.211%	5.096%
Rate of compensation increase-weighted average	3.87 %	3.73 %	3.86 %	3.71 %
Healthcare cost trend rate				
Immediate rate	n/a	n/a	7.09 %	7.25 %
Ultimate rate	n/a	n/a	4.57 %	4.50 %
Year rate reaches ultimate	n/a	n/a	2025	2025

A one-percentage-point change in assumed health care cost trend rates would have the following effect on TEC's benefit obligation:

(millions)	1% Increase	1 % Decrease
Effect on postretirement benefit obligation	$ 3.7	$ (3.6)

The discount rate assumption used to determine the Dec. 31, 2014 benefit obligation was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

Amounts recognized in Net Periodic Benefit Cost, OCI, and Regulatory Assets

TECO Energy	Pension Benefits			Other Benefits		
	2014	2013	2012	2014	2013	2012
(millions)						
Service cost	$18.3	$18.2	$17.0	$2.5	$2.5	$2.4
Interest cost	32.0	28.9	30.1	10.8	9.3	10.1
Expected return on plan assets	(41.8)	(38.4)	(37.1)	(0.3)	0.0	0.0
Amortization of:						
Actuarial loss	13.5	20.5	15.3	0.2	1.0	0.1
Prior service (benefit) cost	(0.4)	(0.4)	(0.4)	(0.2)	(0.4)	0.8
Transition obligation	0.0	0.0	0.0	0.0	0.0	1.8
Curtailment loss (gain)	3.9	0.0	0.0	(0.2)	0.0	0.0
Special termination benefit	0.2	0.0	0.0	0.0	0.0	0.0
Settlement loss	0.0	1.0	0.0	0.0	0.0	0.0
Net periodic benefit cost	$25.7	$29.8	$24.9	$12.8	$12.4	$15.2
Prior service cost	$0.0	$0.0	$0.0	$(23.6)	$0.0	$(5.2)
Net loss (gain)	44.1	(75.7)	34.0	(9.9)	(15.6)	16.3
Unrecognized costs in regulated asset acquired in business combination	0.0	0.0	0.0	6.4	0.0	0.0
Amortization of:						
Actuarial gain (loss)	(13.5)	(21.5)	(15.3)	(0.2)	(1.0)	(0.1)
Prior service (benefit) cost	0.4	0.4	0.4	0.2	0.3	(0.8)
Transition obligation	0.0	0.0	0.0	0.0	0.0	(1.8)
Total recognized in OCI and regulatory assets	$31.0	$(96.8)	$19.1	$(27.1)	$(16.3)	$8.4
Total recognized in net periodic benefit cost, OCI and regulatory assets	$56.7	$(67.0)	$44.0	$(14.3)	$(3.9)	$23.6

TEC's portion of the net periodic benefit costs for pension benefits was $14.8 million, $21.7 million and $18.3 million for 2014, 2013 and 2012, respectively. TEC's portion of the net periodic benefit costs for other benefits was $10.4 million, $10.0 million and $12.4 million for 2014, 2013 and 2012, respectively.

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized by TEC from regulatory assets into net periodic benefit cost over the next fiscal year are $10.0 million and $0.1 million, respectively. There will be no net loss and an estimated $1.9 million prior service credit that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year for the other postretirement benefit plan.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31:

	Pension Benefits			Other Benefits		
	2014 (a)	2013	2012	2014	2013	2012
Discount rate	5.118%/4.2196%/4.3197%	[illegible]	[illegible]	5.096%	4.180%	4.744%
Expected long-term return on plan assets	7.25%/7.00%/7.00%	7.50%	7.50 %	5.75	n/a	n/a
Rate of compensation increase	3.73%	3.76 %	3.83 %	3.71 %	3.74 %	3.82 %
Healthcare cost trend rate						
Initial rate	n/a	n/a	n/a	7.25 %	7.50 %	7.75 %

Ultimate rate	n/a	n/a	n/a	4.50 %	4.50 %	4.50 %
Year rate reaches ultimate	n/a	n/a	n/a	2025	2025	2025

(a) TECO Energy performed a valuation as of Jan. 1, 2014. TECO remeasured its Retirement Plan on Sept. 2, 2014 for the acquisition of NMGC and on Oct. 31, 2014 for the expected curtailment of TECO Coal, resulting in the respective updated discount rates and EROAs.

The discount rate assumption used to determine the 2014 benefit cost was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

The expected return on assets assumption was based on historical returns, fixed income spreads and equity premiums consistent with the portfolio and asset allocation. A change in asset allocations could have a significant impact on the expected return on assets. Additionally, expectations of long-term inflation, real growth in the economy and a provision for active management and expenses paid were incorporated in the assumption. For the year ended Dec. 31, 2014, TECO Energy's pension plan experienced actual asset returns of approximately 7.9%.

The compensation increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases.

A one-percentage-point change in assumed health care cost trend rates would have the following effect on TEC's expense:

(millions)	1% Increase	1% Decrease
Effect on periodic cost	$ 0.3	$ (0.3)

Pension Plan Assets

Pension plan assets (plan assets) are invested in a mix of equity and fixed income securities. TECO Energy's investment objective is to obtain above-average returns while minimizing volatility of expected returns and funding requirements over the long term. TECO Energy's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

	Target Allocation	Actual Allocation, End of Year	
Asset Category		2014	2013
Equity securities	48%-54%	50 %	54 %
Fixed income securities	46%-52%	50 %	46 %
Total	100%	100 %	100 %

TECO Energy reviews the plan's asset allocation periodically and re-balances the investment mix to maximize asset returns, optimize the matching of investment yields with the plan's expected benefit obligations, and minimize pension cost and funding. TECO Energy, Inc. expects to take additional steps to more closely match plan assets with plan liabilities.

The plan's investments are held by a trust fund administered by JP Morgan Chase Bank, N.A. (JP Morgan). JP Morgan measures fair value using the procedures set forth below for all investments. When available, JP Morgan uses quoted market prices on investments traded on an exchange to determine fair value and classifies such items as Level 1. In some cases where a market exchange price is available, but the investments are traded in a secondary market, JP Morgan makes use of acceptable practical expedients to calculate fair value, and the company classifies these items as Level 2.

If observable transactions and other market data are not available, fair value is based upon third-party developed models that use, when available, current market-based or independently-sourced market parameters such as interest rates, currency rates or option volatilities. Items valued using third-party generated models are classified according to the lowest level input or value driver that is most significant to the valuation. Thus, an item may be classified in Level

3 even though there may be significant inputs that are readily observable.

As required by the fair value accounting standards, the investments are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The plan's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For cash equivalents, the cost approach was used in determining fair value. For bonds and U.S. government agencies, the income approach was used. For other investments, the market approach was used. The following table sets forth by level within the fair value hierarchy the plan's investments as of Dec. 31, 2014 and 2013.

Pension Plan Investments

(millions)	At Fair Value as of Dec. 31, 2014			
	Level 1	Level 2	Level 3	Total
Cash	$0.4	$0.0	$ 0.0	$0.4
Accounts receivable	1.4	0.0	0.0	1.4
Accounts payable	(5.3)	0.0	0.0	(5.3)
Cash equivalents				
Short term investment funds (STIFs)	7.6	0.0	0.0	7.6
Treasury bills (T bills)	0.0	0.2	0.0	0.2
Discounted notes	0.0	8.8	0.0	8.8
Total cash equivalents	7.6	9.0	0.0	16.6
Equity securities				
Common stocks	98.0	0.0	0.0	98.0
American depository receipts (ADRs)	1.3	0.0	0.0	1.3
Real estate investment trusts (REITs)	2.5	0.0	0.0	2.5
Preferred stock	0.8	0.0	0.0	0.8
Mutual funds	171.3	0.0	0.0	171.3
Commingled fund	0.0	45.6	0.0	45.6
Total equity securities	273.9	45.6	0.0	319.5
Fixed income securities				
Municipal bonds	0.0	6.1	0.0	6.1
Government bonds	0.0	47.9	0.0	47.9
Corporate bonds	0.0	22.0	0.0	22.0
Asset backed securities (ABS)	0.0	0.3	0.0	0.3
Mortgage-backed securities (MBS), net short sales	0.0	9.6	0.0	9.6
Collateralized mortgage obligations (CMOs)	0.0	2.0	0.0	2.0
Mutual fund	0.0	98.6	0.0	98.6
Commingled fund	0.0	129.2	0.0	129.2
Total fixed income securities	0.0	315.7	0.0	315.7
Derivatives				
Short futures	0.0	(0.3)	0.0	(0.3)
Purchased options (swaptions)	0.0	0.7	0.0	0.7
Written options (swaptions)	0.0	(0.8)	0.0	(0.8)
Total derivatives	0.0	(0.4)	0.0	(0.4)
Miscellaneous	0.0	0.1	0.0	0.1
Total	$278.0	$370.0	$ 0.0	$648.0

Pension Plan Investments

(millions)	At Fair Value as of Dec. 31, 2013			
	Level 1	Level 2	Level 3	Total
Accounts receivable	$44.7	$0.0	$ 0.0	$44.7
Accounts payable	(40.8)	0.0	0.0	(40.8)
Cash equivalents				
Short term investment funds (STIFs)	7.9	0.0	0.0	7.9
Treasury bills (T bills)	0.0	0.3	0.0	0.3
Repurchase agreement	0.0	8.8	0.0	8.8
Commercial paper	0.0	0.4	0.0	0.4
Money markets	0.0	1.5	0.0	1.5
Total cash equivalents	7.9	11.0	0.0	18.9
Equity securities				
Common stocks	91.6	0.0	0.0	91.6
American depository receipts (ADRs)	3.0	0.0	0.0	3.0
Real estate investment trusts (REITs)	1.7	0.0	0.0	1.7
Preferred stock	0.0	0.8	0.0	0.8
Mutual funds	172.6	0.0	0.0	172.6
Commingled fund	0.0	50.0	0.0	50.0
Total equity securities	268.9	50.8	0.0	319.7
Fixed income securities				
Municipal bonds	0.0	7.3	0.0	7.3
Government bonds	0.0	35.7	0.0	35.7
Corporate bonds	0.0	19.6	0.0	19.6
Asset backed securities (ABS)	0.0	0.4	0.0	0.4
Mortgage-backed securities (MBS), net short sales	0.0	6.7	0.0	6.7
Collateralized mortgage obligations (CMOs)	0.0	2.3	0.0	2.3
Mutual fund	0.0	85.1	0.0	85.1
Commingled fund	0.0	94.1	0.0	94.1
Total fixed income securities	0.0	251.2	0.0	251.2
Derivatives				
Short futures	0.0	0.2	0.0	0.2
Swaps	0.0	(0.9)	0.0	(0.9)
Purchased options (swaptions)	0.0	0.2	0.0	0.2
Written options (swaptions)	0.0	(0.4)	0.0	(0.4)
Total derivatives	0.0	(0.9)	0.0	(0.9)
Miscellaneous	0.0	0.2	0.0	0.2
Total	$280.7	$312.3	$ 0.0	$593.0

- The primary pricing inputs in determining the fair value of the Level 1 assets, excluding the mutual funds and STIF, are closing quoted prices in active markets.
- The STIF is valued at net asset value (NAV) as determined by JP Morgan. Shares may be redeemed any business day at the NAV calculated after the order is accepted. The NAV is validated with purchases and sales at NAV, making this a Level 1 asset.
- The primary pricing inputs in determining the Level 1 mutual funds are the mutual funds' NAVs. The funds are registered open-ended mutual funds and the NAVs are validated with purchases and sales at NAV, making these Level 1 assets.
- The repurchase agreements and money markets are valued at cost due to their short term nature. Additionally, repurchase agreements are backed by collateral.

- T bills and commercial paper are valued using benchmark yields, reported trades, broker dealer quotes, and benchmark securities.
- The primary pricing inputs in determining the fair value of the preferred stock is the price of underlying and common stock of the same issuer, average life, and benchmark yields.
- The methodology and inputs used to value the investment in the equity commingled fund are broker dealer quotes. The fund holds primarily international equity securities that are actively traded in OTC markets. The fund honors subscription and redemption activity on an “as of” basis.

- The primary pricing inputs in determining the fair value Level 2 municipal bonds are benchmark yields, historical spreads, sector curves, rating updates, and prepayment schedules. The primary pricing inputs in determining the fair value of government bonds are the U.S. Treasury curve, CPI, and broker quotes, if available. The primary pricing inputs in determining the fair value of corporate bonds are the U.S. treasury curve, base spreads, YTM, and benchmark quotes. ABS and CMOs are priced using TBA prices, treasury curves, swap curves, cash flow information, and bids and offers as inputs. MBS are priced using TBA prices, treasury curves, average lives, spreads, and cash flow information. Commercial MBS are priced using payment information and yields.
- The primary pricing input in determining the fair value of the Level 2 mutual fund is its NAV. However, since this mutual fund is an unregistered open-ended mutual fund, it is a Level 2 asset.
- The fixed income commingled fund is a private fund valued at NAV as determined by a third party at year end. The fund invests in long duration U.S. investment-grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The NAV is calculated based on bid prices of the underlying securities. The fund honors subscription activity on the first business day of the month and the first business day following the 15th calendar day of the month. Redemptions are honored on the 15th or last business day of the month, providing written notice is given at least ten business days prior to withdrawal date.
- Futures are valued using futures data, cash rate data, swap rates, and cash flow analyses.
- Swaps are valued using benchmark yields, swap curves, and cash flow analyses.
- Options are valued using the bid-ask spread and the last price.

Other Postretirement Benefit Plan Assets

There are no assets associated with TECO Energy’s other postretirement benefits plan. Asset amounts shown in the tables above relate to a separate NMGC other postretirement benefit plan.

Contributions

TECO Energy’s policy is to fund the qualified pension plan at or above amounts determined by its actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. TECO Energy made $47.5 million of contributions to this plan in 2014 and $42.0 million in 2013, which met the minimum funding requirements for both 2014 and 2013. TEC’s portion of the contribution in 2014 was $38.2 million and in 2013 was $33.5 million. These amounts are reflected in the “Other” line on the Consolidated Statements of Cash Flows. TECO Energy estimates its contribution in 2015 to be $43.7 million, with TEC’s portion being $33.5 million. TECO Energy estimates it will make annual contributions from 2016 to 2019 ranging from $2.5 to $36.5 million per year based on current assumptions, with TEC’s portion to range from $1.5 million to $29.0 million. These amounts are in excess of the minimum funding required under ERISA guidelines.

The SERP is funded annually to meet the benefit obligations. TECO Energy made contributions of $1.2 million and $2.6 million to this plan in 2014 and 2013, respectively. TEC’s portion of the contributions in 2014 and 2013 were $0.8 million and $1.0 million, respectively. In 2015, TECO Energy expects to make a contribution of about $4.9 million to this plan. TEC’s portion of the expected contribution is about $0.6 million.

The other postretirement benefits are funded annually to meet benefit obligations. TECO Energy’s contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and Jun. 30, 2001 is limited to a defined dollar benefit based on service. TECO Energy’s contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after July 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. In 2015, TECO Energy expects to make a contribution of about $14.3 million. TEC’s portion of the expected contribution is $9.1 million. Postretirement benefit levels are substantially unrelated to salary.

Benefit Payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Expected Benefit Payments—TECO Energy

(including projected service and net of employee contributions) (millions)	Pension Benefits	Other Postretirement Benefits
2015	$ 73.4	$ 11.5
2016	47.9	12.0
2017	47.8	12.5
2018	51.9	12.9
2019	58.3	13.4
2020-2024	285.5	69.5

Defined Contribution Plan

TECO Energy has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. TECO Energy and its subsidiaries match up to 6% of the participant's payroll savings deductions. Effective April 2013, employer matching contributions were 65% of eligible participant contributions with additional incentive match of up to 35% of eligible participant contributions based on the achievement of certain operating company financial goals. Prior to this, the employer matching contributions were 60% of eligible participant contributions with additional incentive match of up to 40%. For the years ended Dec. 31, 2014, 2013 and 2012, TECO Energy and its subsidiaries recognized expense totaling $13.1 million, $11.3 million and $7.0 million, respectively, related to the matching contributions made to this plan. TEC's portion of expense totaled $10.2 million, $9.1 million and $6.0 million for 2014, 2013 and 2012, respectively.

Effective Jan. 1, 2015, the employer matching contribution will increase to 70% of eligible participant contributions with additional incentive match of up to 30%

6. Short-Term Debt

At Dec. 31, 2014 and 2013, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2014			Dec. 31, 2013		
(millions)	Credit Facilities	Borrowings Outstanding [1]	Letters of Credit Outstanding	Credit Facilities	Borrowings Outstanding [1]	Letters of Credit Outstanding
Tampa Electric Company:						
5-year facility [2]	$325.0	$ 12.0	$ 0.6	$325.0	$ 6.0	$ 0.7

1-year accounts receivable facility	150.0	46.0	0.0	150.0	78.0	0.0
Total	$475.0	$ 58.0	$ 0.6	$475.0	$ 84.0	$ 0.7

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.

At Dec. 31, 2014, these credit facilities required commitment fees ranging from 12.5 to 30.0 basis points. The weighted-average interest rate on borrowings outstanding under the credit facilities at Dec. 31, 2014 and 2013 was 0.7% and 0.56%, respectively.

Tampa Electric Company Accounts Receivable Facility

On Feb. 3, 2015, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 13 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A., Inc. as Program Agent. The amendment extends the maturity date to Apr.14, 2015.

Amendment of Tampa Electric Company Credit Facility

On Dec. 17, 2013, TEC amended and restated its $325 million bank credit facility, entering into a Fourth Amended and Restated Credit Agreement. The amendment (i) extended the maturity date of the credit facility from Oct. 25, 2016 to Dec. 17, 2018 (subject to further extension with the consent of each lender); (ii) continues to allow TEC to borrow funds at a rate equal to the London interbank deposit rate plus a margin; (iii) as an alternative to the above interest rate, allows TEC to borrow funds at an interest rate equal to a margin plus the higher of Citibank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (iv) allows TEC to borrow funds on a same-day basis under a swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (v) continues to allow TEC to request the lenders to increase their commitments under the credit facility by up to $175 million in the aggregate; (vi) includes a $200 million letter of credit facility; and (vii) made other technical changes.

On Sept. 30, 2014, TEC entered into an amendment of its $325 million bank credit facility, which reallocated commitments among the lenders and made certain other technical changes.

7. Long-Term Debt

A substantial part of Tampa Electric’s tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric’s first mortgage bond indenture, and Tampa Electric could cause the lien associated with this indenture to be released at any time.

Issuance of Tampa Electric Company 4.35% Notes due 2044

On May 15, 2014, TEC completed an offering of $300 million aggregate principal amount of 4.35% Notes due 2044 (the TEC 2014 Notes). The TEC 2014 Notes were sold at 99.933% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, estimated offering expenses and before settlement of interest rate swaps) of approximately $296.6 million. Net proceeds were used to repay short-term debt and for general corporate purposes. TEC may redeem all or any part of the TEC 2014 Notes at its option at any time and from time to time before Nov. 15, 2043 at a redemption price equal to the greater of (i) 100% of the principal amount of TEC 2014 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the notes to be redeemed, discounted at an applicable treasury rate (as defined in the indenture), plus 15 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Nov. 15, 2043, TEC may at its option redeem the TEC 2014 Notes, in whole or in part, at 100% of the principal amount of the notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

Purchase in Lieu of Redemption of Revenue Refunding Bonds

On Sept. 3, 2013, TEC purchased in lieu of redemption $51.6 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 B (the Series 2007 B HCIDA Bonds). On Mar. 26, 2008, the HCIDA had remarketed the Series 2007 B HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2007 B HCIDA Bonds bore interest at a term rate of 5.15% per annum from Mar. 26, 2008 to Sept. 1, 2014. TEC is responsible for payment of the interest and principal associated with the Series 2007 B HCIDA Bonds.

On Mar. 15, 2012, TEC purchased in lieu of redemption $86.0 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (Non-AMT) (the Series 2006 HCIDA Bonds). On Mar. 19, 2008, the HCIDA had remarketed the Series 2006 HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2006 HCIDA Bonds bore interest at a term rate of 5.00% per annum from Mar. 19, 2008 to Mar. 15, 2012. TEC is responsible for payment of the interest and principal associated with the Series 2006 HCIDA Bonds. Regularly scheduled principal and interest when due, are insured by Ambac Assurance Corporation.

As of Dec. 31, 2014, $232.6 million of bonds purchased in lieu of redemption were held by the trustee at the direction of TEC to provide an opportunity to evaluate refinancing alternatives.

8. Other Comprehensive Income

TEC reported the following OCI (loss) for the years ended Dec. 31, 2014, 2013 and 2012, related to the amortization of prior settled amounts and changes in the fair value of cash flow hedges:

Other Comprehensive Income

(millions)	Gross	Tax	Net
2014			
Unrealized gain (loss) on cash flow hedges	$0.0	$0.0	$0.0
Reclassification from AOCI to net income	1.1	(0.4)	0.7
Gain (Loss) on cash flow hedges	1.1	(0.4)	0.7
Total other comprehensive income (loss)	$1.1	$(0.4)	$0.7
2013			
Unrealized gain (loss) on cash flow hedges	$0.0	$0.0	$0.0
Reclassification from AOCI to net income	1.4	(0.5)	0.9
Gain (Loss) on cash flow hedges	1.4	(0.5)	0.9
Total other comprehensive income (loss)	$1.4	$(0.5)	$0.9
2012			
Unrealized gain (loss) on cash flow hedges	$(8.0)	$3.1	$(4.9)
Reclassification from AOCI to net income	1.4	(0.6)	0.8
Gain (Loss) on cash flow hedges	(6.6)	2.5	(4.1)
Total other comprehensive income (loss)	$(6.6)	$2.5	$(4.1)

Accumulated Other Comprehensive Loss

(millions) As of Dec. 31,	2014	2013
Net unrealized losses from cash flow hedges [(1)]	$(7.1)	$(7.8)
Total accumulated other comprehensive loss	$(7.1)	$(7.8)

(1) Net of tax benefit of $4.5 million and $4.9 million as of Dec. 31, 2014 and Dec. 31, 2013, respectively.

9. Commitments and Contingencies

Legal Contingencies

From time to time, TEC and its subsidiaries are involved in various legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with accounting standards for contingencies to provide for matters that are probable of resulting in an estimable loss. While the outcome of such proceedings is uncertain, management does not believe that their ultimate resolution will have a material adverse effect on the company’s results of operations, financial condition or cash flows.

Peoples Gas Legal Proceedings

In November 2010, heavy equipment operated at a road construction site being conducted by Posen Construction, Inc. struck a natural gas line causing a rupture and ignition of the gas and an outage in the natural gas service to Lee and Collier counties, Florida. PGS filed suit in April 2011 against Posen Construction, Inc. in Federal Court for the Middle District of Florida to recover damages for repair and restoration relating to the incident and Posen Construction, Inc. counter-claimed against PGS alleging negligence. In the first quarter of 2014, the parties entered into a settlement agreement that resolves the claims of the parties. In addition, the suit filed in November 2011 by the Posen Construction, Inc. employee operating the heavy equipment involved in the incident in Lee County Circuit Court against PGS and a PGS contractor involved in the project, seeking damages for his injuries, remains pending.

Tampa Electric Legal Proceedings

Three former or inactive TEC employees were maintaining a suit against TEC in Hillsborough County Circuit Court, Florida for personal injuries allegedly caused by exposure to a chemical substance at one of TEC's power stations. The suit was originally filed in 2002, and the trial judge allowed the plaintiffs to seek punitive damages in connection with their case. In the first quarter of 2014 all plaintiffs voluntarily dismissed their suits with prejudice.

A thirty-six year old man died from mesothelioma in March 2014. His estate and his family are suing Tampa Electric as a result. The man allegedly suffered exposure to asbestos dust brought home by his father and grandfather, both of whom had been employed as insulators and worked at various job sites throughout the Tampa area. Plaintiff's case against Tampa Electric and nineteen other defendants alleges, among other things, negligence, strict liability, household exposure, loss of consortium, and wrongful death.

In September 2014, a man was electrocuted when allegedly two energized, downed primary conductors fell during a heavy storm, leading to his death. Plaintiff's wrongful death complaint against Tampa Electric alleges, among other things, negligence and code violations.

The company believes the claims in the pending actions described above in this item are without merit and intends to defend each matter vigorously. The company is unable at this time to estimate the possible loss or range of loss with respect to these matters.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and Peoples Gas divisions, is a PRP for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2014, TEC has estimated its ultimate financial liability to be $33.3 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other" on the Consolidated Balance Sheets. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer rates.

The estimated amounts represent only the portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC's experience with similar work, adjusted for site-specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's actual percentage of the remediation costs.

Factors that could impact these estimates include the ability of other PRPs to pay their pro-rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Long-Term Commitments

TEC has commitments under long-term leases, primarily for building space, capacity payments, vehicles, office equipment and heavy equipment. Rental expense for these leases included in "Regulated operations & maintenance – Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2014, 2013 and 2012, totaled $4.1 million, $2.3 million and $2.2 million, respectively. In addition, Tampa Electric has other purchase obligations, including its outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year, capacity payments under PPAs, and other net purchase obligations/commitments at Dec. 31, 2014:

(millions)	Capacity Payments	Operating Leases[1]	Net Purchase Obligations/Commitments[1]	Total
Year ended Dec. 31:				
2015	$ 30.0	$ 6.7	$ 203.2	$239.9
2016	14.6	6.1	86.8	107.5
2017	9.9	5.2	19.8	34.9
2018	10.1	4.5	5.2	19.8
2019	0.0	4.4	5.3	9.7
Thereafter	0.0	13.0	0.0	13.0
Total future minimum payments	$ 64.6	$ 39.9	$ 320.3	$424.8

(1) Excludes payment obligations under contractual agreements of Tampa Electric and PGS for fuel, fuel transportation and power purchases which are recovered from customers under regulatory clauses approved by the FPSC annually.

Guarantees and Letters of Credit

TEC accounts for guarantees in accordance with the applicable accounting standards. Upon issuance or modification of a guarantee the company determines if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability, and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative) are likely to be subject to the recognition and measurement, as well as the disclosure provisions. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

At Dec. 31, 2014, TEC was not obligated under guarantees, but had the following letters of credit outstanding.

Letters of Credit-Tampa Electric Company

(millions)	Year of Expiration			Maximum	
			After [1]	Theoretical	Liabilities Recognized
Letter of Credit for the Benefit of:	2015	2016-2019	2019	Obligation	at Dec. 31, 2014 [2]
TEC	$0.0	$ 0.0	$ 0.6	$ 0.6	$ 0.1

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2019.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation of TEC under these agreements at Dec. 31, 2014. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.

Financial Covenants

In order to utilize their respective bank credit facilities, TEC must meet certain financial tests as defined in the applicable agreements. In addition, TEC has certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2014, TEC was in compliance with all required financial covenants.

10. Related Party Transactions

A summary of activities between TEC and its affiliates follows:

Net transactions with affiliates:

(millions)	2014	2013	2012

Natural gas sales, net	$0.3	$18.3	$11.7
Administrative and general, net	$22.5	$27.2	$23.4

Amounts due from or to affiliates at Dec. 31,

(millions)	2014	2013
Accounts receivable(1)	$2.4	$1.3
Accounts payable(1)	9.7	9.8
Taxes receivable(2)	43.3	54.9
Taxes payable	0.0	0.4

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest.

(2) Taxes receivable is due from TECO Energy.

155

TEC had certain transactions, in the ordinary course of business, with entities in which directors of TEC had interests. TEC paid legal fees of $1.7 million and $1.2 million for the years ended Dec. 31, 2013 and 2012, respectively, to Ausley McMullen, P.A. of which Mr. Ausley (who was a director of TECO Energy, until his retirement from the Board in May 2013) was an employee.

11. Segment Information

TEC is a public utility operating within the State of Florida. Through its Tampa Electric division, it is engaged in the generation, purchase, transmission, distribution and sale of electric energy to more than 706,000 customers in West Central Florida. Its PGS division is engaged in the purchase, distribution and marketing of natural gas for almost 354,000 residential, commercial, industrial and electric power generation customers in the State of Florida.

(millions)	Tampa Electric	PGS	Eliminations	TEC
2014				
Revenues - external	$2,020.5	$398.5	$ 0.0	$2,419.0
Sales to affiliates	0.5	1.1	(1.6)	0.0
Total revenues	2,021.0	399.6	(1.6)	2,419.0
Depreciation and amortization	248.6	54.0	0.0	302.6
Total interest charges	92.8	13.8	0.0	106.6
Provision for income taxes	133.2	22.7	0.0	155.9
Net income	224.5	35.8	0.0	260.3
Total assets	6,234.4	1,047.0	(7.1)	7,274.3
Capital expenditures	592.6	88.9	0.0	681.5
2013				
Revenues - external	$1,950.1	$392.7	$ 0.0	$2,342.8
Sales to affiliates	0.4	0.8	(1.2)	0.0
Total revenues	1,950.5	393.5	(1.2)	2,342.8
Depreciation and amortization	238.8	51.5	0.0	290.3
Total interest charges	91.8	13.5	0.0	105.3
Provision for income taxes	116.9	21.9	0.0	138.8
Net income	190.9	34.7	0.0	225.6
Total assets	5,895.4	989.3	(8.9)	6,875.8
Capital expenditures	428.6	79.0	0.0	507.6
2012				
Revenues - external	$1,980.9	$397.1	$ 0.0	$2,378.0
Sales to affiliates	0.4	1.8	(2.2)	0.0
Total revenues	1,981.3	398.9	(2.2)	2,378.0
Depreciation and amortization	237.6	50.6	0.0	288.2
Total interest charges	109.8	16.0	0.0	125.8
Provision for income taxes	120.2	21.5	0.0	141.7
Net income	193.1	34.1	0.0	227.2
Total assets	5,760.4	970.9	13.3	6,744.6
Capital expenditures	361.7	97.3	0.0	459.0

12. Asset Retirement Obligations

TEC accounts for AROs under the applicable accounting standards. An ARO for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its estimated future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

As regulated utilities, Tampa Electric and PGS must file depreciation and dismantlement studies periodically and receive approval from the FPSC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components—a salvage factor and a cost of removal or dismantlement factor. TEC uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

For Tampa Electric and PGS, the original cost of utility plant retired or otherwise disposed of and the cost of removal or dismantlement, less salvage value, is charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively.

Reconciliation of beginning and ending carrying amount of asset retirement obligations:

	Dec. 31,	
(millions)	2014	2013
Beginning balance	$4.8	$5.0
Additional liabilities	0.1	0.1
Liabilities settled	0.0	(0.2)
Revisions to estimated cash flows	0.2	(0.3)
Other (1)	0.2	0.2
Ending balance	$5.3	$4.8

(1) Accretion recorded as a deferred regulatory asset.

13. Accounting for Derivative Instruments and Hedging Activities

From time to time, TEC enters into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations, and
- To limit the exposure to interest rate fluctuations on debt securities.

TEC uses derivatives only to reduce normal operating and market risks, not for speculative purposes. TEC's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers.

The risk management policies adopted by TEC provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group, which is independent of all operating companies.

TEC applies the accounting standards for derivative instruments and hedging activities. These standards require companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value and to reflect the changes in the fair value of those instruments as either components of OCI or in net income, depending on the designation of those instruments (see Note 14). The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of the instrument's settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the market change of the amount paid or received on the underlying physical transaction.

TEC applies the accounting standards for regulated operations to financial instruments used to hedge the purchase of natural gas for its regulated companies. These standards, in accordance with the FPSC, permit the changes in fair value of natural gas derivatives to be recorded as regulatory assets or liabilities reflecting the impact of hedging activities on the fuel recovery clause. As a result, these changes are not recorded in OCI (see Note 3).

TEC's physical contracts qualify for the NPNS exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if TEC deems the counterparty creditworthy, if the counterparty owns or controls resources within the proximity to allow for physical delivery of the commodity, if TEC intends to receive physical delivery and if the transaction is reasonable in relation to TEC's business needs. As of Dec. 31, 2014, all of TEC's physical contracts qualify for the NPNS exception.

The derivatives that are designated as cash flow hedges at Dec. 31, 2014 and 2013 are reflected on TEC's Consolidated Balance Sheets and classified accordingly as current and long term assets and liabilities on a net basis as permitted by their respective master netting agreements. Derivative assets totaled $0 and $9.8 million as of Dec. 31, 2014 and 2013, respectively, and derivative liabilities totaled $42.7 million and $0.2 million as of Dec. 31, 2014 and 2013, respectively. There are minor offset amount differences between the gross derivative assets and liabilities and the net amounts presented on the Consolidated Balance Sheets. There was no collateral posted with or received from any counterparties.

All of the derivative asset and liabilities at Dec. 31, 2014 and 2013 are designated as hedging instruments, which primarily are derivative hedges of natural gas contracts to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers. The corresponding effect of these natural gas related derivatives on the regulated utilities' fuel recovery clause mechanism is reflected on the Consolidated Balance Sheets as current and long term regulatory assets and liabilities. Based on the fair value of the instruments at Dec. 31, 2014, net pretax losses of $36.6 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The Dec. 31, 2014 and 2013 balance in AOCI related to the cash flow hedges and previously settled interest rate swaps is presented in Note 8.

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or period during which the hedged transaction affects earnings. Gains and losses on the derivatives representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For the years ended Dec. 31, 2014, 2013 and 2012, all hedges were effective. The derivative after-tax effect on OCI and the amount of after-tax gain or loss reclassified from AOCI into earnings for years ended Dec. 31, 2014, 2013 and 2012 is presented in Note 8. Gains and losses were the result of interest rate contracts and the reclassifications to income were reflected in Interest expense.

The maximum length of time over which TEC is hedging its exposure to the variability in future cash flows extends to Dec. 31, 2016 for financial natural gas contracts. The following table presents TEC's derivative volumes that, as of Dec. 31, 2014, are expected to settle during the 2015 and 2016 fiscal years:

(millions)	Natural Gas Contracts (MMBTUs)	
Year	Physical	Financial
2015	0.0	32.4
2016	0.0	8.6
Total	0.0	41.0

TEC is exposed to credit risk primarily through entering into derivative instruments with counterparties to limit its exposure to the commodity price fluctuations associated with natural gas. Credit risk is the potential loss resulting from a counterparty's nonperformance under an agreement. TEC manages credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement and exposure monitoring and mitigation.

It is possible that volatility in commodity prices could cause TEC to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, TEC could suffer a material financial loss. However, as of Dec. 31, 2014, substantially all of the counterparties with transaction amounts outstanding in TEC's energy portfolio were rated investment grade by the major rating agencies. TEC assesses credit risk internally for counterparties that are not rated.

TEC has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. TEC generally enters into the following master arrangements: (1) EEI agreements—standardized power sales contracts in the electric industry; (2) ISDA agreements—standardized financial gas and electric contracts; and (3) NAESB agreements—standardized physical gas contracts. TEC believes that entering into such agreements reduces the risk from default by creating contractual rights relating to creditworthiness, collateral and termination.

TEC has implemented procedures to monitor the creditworthiness of its counterparties and to consider nonperformance risk in determining the fair value of counterparty positions. Net liability positions are generally not adjusted as TEC uses derivative transactions as hedges and has the ability and intent to perform under each of these contracts. In the instance of net asset positions, TEC considers general market conditions and the observable financial health and outlook of specific counterparties in evaluating the potential impact of nonperformance risk to derivative positions. As of Dec. 31, 2014, all positions with counterparties were net liabilities.

Certain TEC derivative instruments contain provisions that require TEC's debt to maintain an investment grade credit rating from any or all of the major credit rating agencies. If debt ratings were to fall below investment grade, it could trigger these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. TEC has no other contingent risk features associated with any derivative instruments.

14. Fair Value Measurements

Items Measured at Fair Value on a Recurring Basis

Accounting guidance governing fair value measurements and disclosures provides that fair value represents the amount that would be received in selling an asset or the amount that would be paid in transferring a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that is determined based upon assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, accounting guidance also establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1: Observable inputs, such as quoted prices in active markets;
Level 2: Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and
Level 3: Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities are measured at fair value based on one or more of the following three valuation techniques noted under accounting guidance:

(A) Market approach: Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities;
(B) Cost approach: Amount that would be required to replace the service capacity of an asset (replacement cost); and
(C) Income approach: Techniques to convert future amounts to a single present amount based upon market expectations (including present value techniques, option-pricing and excess earnings models).

The fair value of financial instruments is determined by using various market data and other valuation techniques.

The following table sets forth by level within the fair value hierarchy TEC's financial assets and liabilities that were accounted for at fair value on a recurring basis as of Dec. 31, 2014 and 2013. As required by accounting standards for fair value measurements, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. TEC's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For all assets and liabilities presented below, the market approach was used in determining fair value.

Recurring Derivative Fair Value Measures

	As of Dec. 31, 2014			
(millions)	Level	Level 2	Level 3	Total
Liabilities				
Natural gas swaps	$0.0	$ 42.7	$ 0.0	$42.7

	As of Dec. 31, 2013			
(millions)	Level	Level 2	Level 3	Total
Assets				
Natural gas swaps	$0.0	$ 9.8	$ 0.0	$9.8
Total	$0.0	$ 9.8	$ 0.0	$9.8
Liabilities				
Natural gas swaps	$0.0	$ 0.2	$ 0.0	$0.2
Total	$0.0	$ 0.2	$ 0.0	$0.2

159

Natural gas swaps are OTC swap instruments. The primary pricing inputs in determining the fair value of natural gas swaps are the NYMEX quoted closing prices of exchange-traded instruments. These prices are applied to the notional amounts of active positions to determine the reported fair value (see Note 13).

TEC considered the impact of nonperformance risk in determining the fair value of derivatives. TEC considered the net position with each counterparty, past performance of both parties, the intent of the parties, indications of credit deterioration and whether the markets in which TEC transacts have experienced dislocation. At Dec. 31, 2014, the fair value of derivatives was not materially affected by nonperformance risk. TEC's net positions with substantially all counterparties were liability positions. There were no Level 3 assets or liabilities during the 2014 or 2013 fiscal years.

15. Variable Interest Entities

The determination of a VIE's primary beneficiary is the enterprise that has both 1) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and 2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

TEC has entered into multiple PPAs with wholesale energy providers in Florida to ensure the ability to meet customer energy demand and to provide lower cost options in the meeting of this demand. These agreements range in size from 117 MW to 370 MW of available capacity, are with similar entities and contain similar provisions. Because some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy, these agreements meet the definition of being VIEs. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. TEC has reviewed these risks and has determined that the owners of these entities have retained the majority of these risks over the expected life of the underlying generating assets, have the power to direct the most significant activities, the obligation or right to absorb losses or benefits and hence remain the primary beneficiaries. As a result, TEC is not required to consolidate any of these entities. TEC purchased $25.7 million, $22.1 million and $75.8 million, under these PPAs for the three years ended Dec. 31, 2014, 2013 and 2012, respectively.

TEC does not provide any material financial or other support to any of the VIEs it is involved with, nor is TEC under any obligation to absorb losses associated with these VIEs. In the normal course of business, TEC's involvement with these VIEs does not affect its Consolidated Balance Sheets, Statements of Income or Cash Flows.

16. Subsequent Events

On Feb. 3, 2015, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 13 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A. as Program Agent. The amendment extends the maturity date to Apr. 14, 2015.

160

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

Item 9A. CONTROLS AND PROCEDURES.

TECO Energy, Inc.

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

TECO Energy's management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of TECO Energy's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this annual report, Dec. 31, 2014 (Evaluation Date). Based on such evaluation, TECO Energy's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, TECO Energy's disclosure controls and procedures are effective.

On Sept. 2, 2014, TECO Energy completed the acquisition of the privately-held NMGI and its wholly owned subsidiary, NMGC. NMGI and NMGC's business combined constitute 15.1% of total assets of TECO Energy at Dec. 31, 2014, and 5.4% of TECO Energy's revenues for the year ended Dec. 31, 2014. As permitted by SEC guidance for newly acquired businesses, because it was not possible to complete an effective assessment of the acquired companies' controls by year-end, TECO Energy's management has excluded NMGI and NMGC from its evaluation of disclosure controls and procedures and management's report on internal control over financial reporting and changes therein below from the date of such acquisition through Dec. 31, 2014. TECO Energy's management is in the process of reviewing the operations of NMGI and NMGC and implementing TECO Energy's internal control structure over the acquired operations.

Management's Report on Internal Control over Financial Reporting.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. We conducted an evaluation of the effectiveness of TECO Energy, Inc.'s internal control over financial reporting as of Dec. 31, 2014 based on the 2013 framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under this framework, our management concluded that TECO Energy, Inc.'s internal control over financial reporting was effective as of Dec. 31, 2014.

TECO Energy's internal control over financial reporting as of Dec. 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which appears herein.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. A control system, no matter how well designed and operated, can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control over Financial Reporting.

TECO Energy's internal control environment was revised in the third quarter of 2014 to include a control process over business combinations. Other than this and excluding the acquisition of NMGI and its wholly owned subsidiary, NMGC, there were no changes in TECO Energy's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of TECO Energy's internal controls that occurred during TECO Energy's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Tampa Electric Company

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

TEC's management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of TEC's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this annual report, Dec. 31, 2014 (Evaluation Date). Based on such evaluation, TEC's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, TEC's disclosure controls and procedures are effective.

Management's Report on Internal Control over Financial Reporting.

TEC's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. We conducted an evaluation of the effectiveness of TEC's internal control over financial reporting as of Dec. 31, 2014 based on the 2013 framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under this framework, our management concluded that TEC's internal control over financial reporting was effective as of Dec. 31, 2014.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. A control system, no matter how well designed and operated, can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control over Financial Reporting.

There was no change in Tampa Electric Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of Tampa Electric Company's internal controls that occurred during Tampa Electric Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Item 9B. OTHER INFORMATION.

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

(a) The information required by Item 10 with respect to the directors of the registrant is included under the caption "Election of Directors" in TECO Energy's definitive proxy statement for its Annual Meeting of Shareholders to be held on April 29, 2015 (Proxy Statement) and is incorporated herein by reference.
(b) The information required by Item 10 concerning executive officers of the registrant is included under the caption "Executive Officers of the Registrant" in Item 1 - Business of this report and is incorporated herein by reference.
(c) The information required by Item 10 concerning Section 16(a) Beneficial Ownership Reporting Compliance is included under that caption in the Proxy Statement and is incorporated herein by reference.
(d) Information regarding TECO Energy's Audit Committee, including the committee's financial experts, is included under the caption "Committees of the Board" in the Proxy Statement, and is incorporated herein by reference.
(e) TECO Energy has adopted a code of ethics applicable to all of its employees, officers and directors. The text of the Code of Ethics and Business Conduct is available in the Corporate Governance section of the Investors page of the company's website at www.tecoenergy.com. Any amendments to or waivers of the Code of Ethics and Business Conduct for the benefit of any executive officer or director will also be posted on the website.

Item 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is included in the Proxy Statement beginning with the caption "Compensation Committee Report" and ending with "Post-Termination Benefits Table" just above the caption "Item 4-Shareholder Proposal" and is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 201(d) of Regulation S-K is included below. The remainder of the information required by Item 12 is included under the caption "Share Ownership" in the Proxy Statement, and is incorporated herein by reference.

Equity Compensation Plan Information

(thousands, except per share price)	(a)		(b)	(c)
Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights [1]		Weighted-average exercise price per share of outstanding options, warrants and rights	Number of securities remaining available for Future issuance under equity compensation plans (excluding securities reflected in column (a)[2]
Equity compensation plans/arrangements approved by the stockholders				
2010 Equity Incentive Plan	840	$	16.32	2,482
Equity compensation plans/arrangements not approved by the stockholders				
None	0		0.00	0
Total	840	$	16.32	2,482

(1) The reported amount for the 2010 Equity Incentive Plan excludes performance shares which have been issued or may potentially be issued due to performance, subject to a performance-based vesting schedule. Because of the nature of these awards, these shares have also not been taken into account in calculating the weighted-average exercise price under column (b) of this table.

(2) The reported amount for the 2010 Equity Incentive Plan includes shares which may be issued as restricted stock, performance shares, performance-accelerated restricted stock, bonus stock, phantom stock, performanc units, dividend equivalents and other forms of award available for grant under the plan.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is included under the captions “Certain Relationships and Related Person Transactions” and “Director Independence” in the Proxy Statement, and is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 for TECO Energy is included under the caption “Item 2 – Ratification of Appointment of Independent Auditor” in the Proxy Statement and is incorporated herein by reference.

TEC incurred $1.0 million, $0.8 million and $0.8 million in audit and audit-related fees rendered by PricewaterhouseCoopers for each of the years 2014, 2013 and 2012, respectively, including $0.3 million related to Sarbanes-Oxley in each of those three years. No other fees for services rendered by PricewaterhouseCoopers were incurred by TEC in those years.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Certain Documents Filed as Part of this Form 10-K

1. Financial Statements

TECO Energy, Inc. Financial Statements

Report of Independent Registered Public Accounting Firm dated February 27, 2015 of PricewaterhouseCoopers LLP

Consolidated Balance Sheets at December 31, 2014 and 2013

Consolidated Statements of Income for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Capital for the Years Ended December 31, 2014, 2013 and 2012

Notes to Consolidated Financial Statements

Tampa Electric Company Financial Statements

Report of Independent Registered Public Accounting Firm dated February 27, 2015 of PricewaterhouseCoopers LLP

Consolidated Balance Sheets at December 31, 2014 and 2013

Consolidated Statements of Income and Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Retained Earnings for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Capitalization for the Years Ended December 31, 2014, 2013 and 2012

Notes to Consolidated Financial Statements

2. Financial Statement Schedules

TECO Energy, Inc. Schedule II

Tampa Electric Company Schedule II

3. Exhibits

(b) The exhibits filed as part of this Form 10-K are listed on the Exhibit Index immediately preceding such Exhibits. The Exhibit Index is incorporated herein by reference.

(c) The financial statement schedules filed as part of this Form 10-K are listed in paragraph (a)(2) above, and follow immediately.

165

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TECO ENERGY, INC.

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

For the Years Ended Dec. 31, 2014, 2013 and 2012

(millions)

	Balance at Beginning of Period	Additions Charged to Income	Other Charges	Payments & Deductions		Balance at End of Period
Allowance for Uncollectible Accounts:						
2014	$ 4.7	$1.4	$ 0.7	$ 4.7	(1)	$ 2.1
2013	$ 4.2	$3.3	$ 0.0	$ 2.8	(1)	$ 4.7
2012	$ 2.6	$4.8	$ 0.0	$ 3.2	(1)	$ 4.2
Deferred Tax Valuation Allowance:						
2014	$ 0.0	$4.6	$ 0.0	$ 0.0		$ 4.6
2013	$ 3.0	$0.0	$ 0.0	$ 3.0	(2)	$ 0.0
2012	$ 9.7	$1.1	$ 0.0	$ 7.8	(2)	$ 3.0

(1) Write-off of individual bad debt accounts
(2) Valuation allowance is no longer required

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TAMPA ELECTRIC COMPANY

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

For the Years Ended Dec. 31, 2014, 2013 and 2012

(millions)

	Balance at Beginning of Period	Additions Charged to Income	Other Charges	Payments & Deductions (1)	Balance at End of Period
Allowance for Uncollectible Accounts:					
2014	$ 2.0	$ 2.7	$ 0.0	$ 3.3	$ 1.4
2013	$ 1.5	$ 3.3	$ 0.0	$ 2.8	$ 2.0
2012	$ 1.3	$ 3.4	$ 0.0	$ 3.2	$ 1.5

(1) Write-off of individual bad debt accounts

SIGNATURES

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.

TECO ENERGY, INC.

Dated: February 27, 2015	By: /s/ JOHN B. RAMIL JOHN B. RAMIL President, Chief Executive Officer and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 27, 2015:

Signature	Title
/s/ JOHN B. RAMIL JOHN B. RAMIL	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ SANDRA W. CALLAHAN SANDRA W. CALLAHAN	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer) (Principal Financial and Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ JAMES L. FERMAN, JR. JAMES L. FERMAN, JR.	Director	/s/ LORETTA A. PENN LORETTA A. PENN	Director
/s/ EVELYN V. FOLLIT EVELYN V. FOLLIT	Director	/s/ TOM L. RANKIN TOM L. RANKIN	Director
/s/ SHERRILL W. HUDSON SHERRILL W. HUDSON	Chairman of the Board and Director	/s/ WILLIAM D. ROCKFORD WILLIAM D. ROCKFORD	Director
/s/ JOSEPH P. LACHER JOSEPH P. LACHER	Director	/s/ PAUL L. WHITING PAUL L. WHITING	Director

SIGNATURES

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.

TAMPA ELECTRIC COMPANY

Dated: February 27, 2015	By: /s/ JOHN B. RAMIL JOHN B. RAMIL Chief Executive Officer and Director (Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 27, 2015:

	Title
/s/ JOHN B. RAMIL JOHN B. RAMIL	Chief Executive Officer and Director (Principal Executive Officer)
/s/ SANDRA W. CALLAHAN SANDRA W. CALLAHAN	Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer) (Principal Financial and Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ JAMES L. FERMAN, JR. JAMES L. FERMAN, JR.	Director	/s/ LORETTA A. PENN LORETTA A. PENN	Director
/s/ EVELYN V. FOLLIT EVELYN V. FOLLIT	Director	/s/ TOM L. RANKIN TOM L. RANKIN	Director
/s/ SHERRILL W. HUDSON SHERRILL W. HUDSON	Chairman of the Board and Director	/s/ WILLIAM D. ROCKFORD WILLIAM D. ROCKFORD	Director
/s/ JOSEPH P. LACHER JOSEPH P. LACHER	Director	/s/ PAUL L. WHITING PAUL L. WHITING	Director

Supplemental Information to Be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act

No annual report or proxy material has been sent to Tampa Electric Company’s security holders because all of its equity securities are held by TECO Energy, Inc.

INDEX TO EXHIBITS

Exhibit No.	Description	
2.1	Equity Purchase Agreement dated as of September 27, 2012 between TECO Guatemala Holdings II, LLC and Sur Eléctrica Holding Limited (Exhibit 10.1, Form 10-Q, for the quarter ended Sep. 30, 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
2.2	Equity Purchase Agreement dated as of September 27, 2012 between TECO Guatemala Holdings II, LLC and Renewable Energy Investments Guatemala Limited (Exhibit 10.2, Form 10-Q, for the quarter ended Sep. 30, 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
2.3	Equity Purchase Agreement dated as of September 27, 2012 between TECO Guatemala Holdings II, LLC and Renewable Energy Investments Guatemala Limited (Exhibit 10.3, Form 10-Q, for the quarter ended Sep. 30, 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
2.4	Equity Purchase Agreement dated as of October 17, 2012 between TECO Guatemala Holdings II, LLC and C.F. Financeco, Ltd. (Exhibit 2.5, Form 10-K for 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
2.5	Stock Purchase Agreement, dated as of May 25, 2013, by and among TECO Energy, Inc., New Mexico Gas Intermediate, Inc. and Continental Energy Systems LLC (Exhibit 2.1, Form 8-K dated May 28, 2013 of TECO Energy, Inc.).	*
2.6	Securities Purchase Agreement dated as of October 17, 2014, by and between TECO Diversified, Inc., as Seller, and Cambrian Coal Corporation, as Purchaser (Exhibit 2.1, Form 8-K dated October 22, 2014, of TECO Energy, Inc.).	*
2.7	Amendment dated as of December 24, 2014 to the Securities Purchase Agreement dated as of October 17, 2014, by and between TECO Diversified, Inc. as Seller, and Cambrian Coal Corporation, as Purchaser (Exhibit 2.1, Form 8-K dated December 24, 2014, of TECO Energy, Inc.).	*
3.1	Amended and Restated Articles of Incorporation of TECO Energy, Inc., as filed on May 3, 2012 (Exhibit 3.1, Form 8-K dated May 4, 2012 of TECO Energy, Inc.).	*
3.2	Bylaws of TECO Energy, Inc., as amended effective May 3, 2012 (Exhibit 3.2, Form 8-K dated May 4, 2012 of TECO Energy, Inc.).	*
3.3	Restated Articles of Incorporation of Tampa Electric Company, as amended on Nov. 30, 1982 (Exhibit 3 to Registration Statement No. 2-70653 of Tampa Electric Company).	*
3.4	Bylaws of Tampa Electric Company, as amended effective Feb. 2, 2011 (Exhibit 3.4, Form 10-K for 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
4.1	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company of Florida, N.A., as trustee, dated as of Jun. 1, 2002 (including the form of bond) (Exhibit 4.5, Amendment No. 1 to Form 10-K for 2004 of TECO Energy, Inc. and Tampa Electric Company).	*

4.2	Loan and Trust Agreement dated as of Jul. 2, 2007 among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee (including the form of Bond) (Exhibit 4.1, Form 8-K dated Jul. 25, 2007 of Tampa Electric Company).	*
4.3	First Supplemental Loan and Trust Agreement dated as of Mar. 26, 2008 among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1, Form 8-K dated Mar. 26, 2008 of Tampa Electric Company).	*
4.4	Loan and Trust Agreement dated as of November 15, 2010 among Tampa Electric Company, Polk County Industrial Development Authority and The Bank of New York Mellon Trust Company, N.A., as trustee (including the form of bond) (Exhibit 4.1, Form 8-K dated Nov. 23, 2010 of Tampa Electric Company).	*
4.5	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee, dated as of Jan. 5, 2006 (including the form of bond) (Exhibit 4.1, Form 8-K dated Jan. 19, 2006 of Tampa Electric Company).	*
4.6	Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Jul. 1, 1998 (Exhibit 4.1, Registration Statement No. 333-55873 of Tampa Electric Company).	*
4.7	Third Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Jun. 15, 2001 (Exhibit 4.2, Form 8-K dated Jun. 25, 2001 of Tampa Electric Company).	*

Exhibit No.	Description	
4.8	Fifth Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of May 1, 2006 (Exhibit 4.16, Form 8-K dated May 12, 2006 of Tampa Electric Company).	*
4.9	Amended and Restated Note Agreement dated as of May 30, 1997 between Tampa Electric Company (successor by merger to Peoples Gas System, Inc.) and The Prudential Insurance Company of America (Exhibit 4.2, Form 8-K dated Dec. 15, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
4.10	Letter Amendment No. 1 dated as of Dec. 9, 2004 to the Amended and Restated Note Agreement dated as of May 30, 1997 between Tampa Electric Company (successor by merger to Peoples Gas System, Inc.) and The Prudential Insurance Company of America (Exhibit 4.1, Form 8-K dated Dec. 15, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
4.11	Note Purchase Agreement among Tampa Electric Company and the Purchasers party thereto, dated as of Apr. 11, 2003 (Exhibit 10.1, Form 8-K dated Apr. 14, 2003 of Tampa Electric Company).	*
4.12	Sixth Supplemental Indenture dated as of May 1, 2007 between Tampa Electric Company and The Bank of New York, as trustee (Exhibit 4.18, Form 8-K dated May 25, 2007 of Tampa Electric Company).	*
4.13	Seventh Supplemental Indenture dated as of May 1, 2008 between Tampa Electric Company and The Bank of New York, as trustee (Exhibit 4.20, Form 8-K dated May 16, 2008 of Tampa Electric Company).	*
4.14	Eighth Supplemental Indenture dated as of Nov. 15, 2010 between Tampa Electric Company, as issuer, and The Bank of New York Mellon, as trustee (including the form of 5.40% Notes due 2021) (Exhibit 4.1, Form 8-K dated Dec. 9, 2010 of Tampa Electric Company).	*
4.15	Ninth Supplemental Indenture dated as of May 31, 2012 between Tampa Electric Company, as issuer, and The Bank of New York Mellon, as trustee, supplementing the Indenture dated as of July 1, 1998, as amended (including the form of 4.10% Notes due 2042) (Exhibit 4.23, Form 8-K dated June 5, 2012 for Tampa Electric Company).	*
4.16	Tenth Supplemental Indenture dated as of September 19, 2012 between Tampa Electric Company, as issuer, and The Bank of New York Mellon, as trustee, supplementing and amending the Indenture dated as of July 1, 1998, as amended (including the form of 2.60% Notes due 2022) (Exhibit 4.25, Form 8-K dated September 28, 2012 for Tampa Electric Company).	*
4.17	Eleventh Supplemental Indenture dated as of May 12, 2014 between Tampa Electric Company, as issuer, and The Bank of New York Mellon, as trustee, supplementing the Indenture dated as of July 1, 1998, as amended (including the form of 4.35% Notes due 2044) (Exhibit 4.27, Form 8-K dated May 15, 2014).	*
4.18	Indenture between TECO Energy, Inc. and The Bank of New York, as trustee, dated as of Aug. 17, 1998 (Exhibit 4.1, Form 8-K dated Sep. 20, 2000 of TECO Energy, Inc.).	*
4.19	Third Supplemental Indenture dated as of Dec. 1, 2000 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.21, Form 8-K dated Dec. 20, 2000 of TECO Energy, Inc.).	*
4.20		*

	Fourth Supplemental Indenture dated as of Apr. 30, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated May 1, 2001 of TECO Energy, Inc.).	
4.21	Fifth Supplemental Indenture dated as of Sep. 10, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.16, Form 8-K dated Sep. 26, 2001 of TECO Energy, Inc.).	*
4.22	Seventh Supplemental Indenture dated as of May 1, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated May 13, 2002 of TECO Energy, Inc.).	*
4.23	Ninth Supplemental Indenture dated as of Jun. 10, 2003 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated Jun. 13, 2003 of TECO Energy, Inc.).	*
4.24	Tenth Supplemental Indenture dated as of May 26, 2005 between TECO Energy, Inc. and The Bank of New York, as trustee (including the form of 6.75% Note) (Exhibit 4.1, Form 8-K dated May 26, 2005 of TECO Energy, Inc.).	*
4.25	Eleventh Supplemental Indenture dated as of Jun. 7, 2005 between TECO Energy, Inc. and The Bank of New York, as trustee (including the form of Floating Rate Note) (Exhibit 4.1, Form 8-K dated Jun. 7, 2005 of TECO Energy, Inc.).	*
4.26	Indenture dated as of Dec. 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*

Exhibit No.	Description	
4.27	First Supplemental Indenture dated as of Dec. 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee (including the form of TECO Finance 7.20% Notes due 2011, TECO Finance 7.00% Notes due 2012 and TECO Finance 6.572% Notes due 2017) (Exhibit 4.2, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*
4.28	Second Supplemental Indenture dated as of Dec. 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee (including the form of TECO Finance 6.75% Notes due 2015) (Exhibit 4.3, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*
4.29	Third Supplemental Indenture dated as of Mar. 15, 2010 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (including the form of TECO Finance 4.00% Notes due 2016 and 5.15% Notes due 2020) (Exhibit 4.26, Form 8-K dated Mar. 15, 2010 of TECO Energy, Inc.).	*
4.30	Twentieth Supplemental Indenture dated as of December 1, 2013 between Tampa Electric Company and US Bank, N.A., as successor trustee, amending and restating the Indenture of Mortgage among Tampa Electric Company, State Street Trust Company and First Savings & Trust Company of Tampa, dated as of Aug. 1, 1946 (Exhibit 4.30, Form 10-K for 2013 of TECO Energy, Inc. and Tampa Electric Company).	*
4.31	Note Purchase Agreement, dated as of February 8, 2011, by and among New Mexico Gas Company, Inc. and the purchasers party thereto (including the Form of Senior Secured Note as Exhibit 1.1 thereto) (Exhibit 4.1, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
4.32	Amendment No. 1 to Note Purchase Agreement, dated as of July 16, 2014, by and between New Mexico Gas Company, Inc. and the noteholders party thereto, to the Note Purchase Agreement dated as of February 8, 2011, by and among New Mexico Gas Company, Inc. and the purchasers party thereto (Exhibit 4.2, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
4.33	Amendment No. 2 to Note Purchase Agreement, dated as of July 16, 2014, by and between New Mexico Gas Company, Inc. and the noteholders party thereto, to the Note Purchase Agreement dated as of February 8, 2011, as amended, by and among New Mexico Gas Company, Inc. and the purchasers party thereto (Exhibit 4.3, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
4.34	Note Purchase Agreement, dated as of July 30, 2014, by and among New Mexico Gas Company, Inc. and the purchasers party thereto (including the Form of Senior Unsecured Note as Exhibit 1 thereto) (Exhibit 4.4, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
4.35	Note Purchase Agreement, dated as of July 30, 2014, by and among New Mexico Gas Intermediate, Inc. and the purchasers party thereto (including the Form of Series A Senior Unsecured Note as Exhibit 1(a) thereto and Form of Series B Senior Unsecured Note as Exhibit 1(b) thereto) (Exhibit 4.5, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
10.1		*

	TECO Energy Group Supplemental Executive Retirement Plan, as amended and restated as of Nov. 1, 2007 (Exhibit 10.1, Form 10-K for 2007 of TECO Energy, Inc. and Tampa Electric Company).	
10.2	TECO Energy Group Supplemental Disability Income Plan, dated as of Mar. 20, 1989 (Exhibit 10.22, Form 10-K for 1988 of TECO Energy, Inc.).	*
10.3	TECO Energy Group Supplemental Retirement Benefits Trust Agreement, effective as of Nov. 17, 2008 (Exhibit 10.3, Form 10-K for 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.4	Annual Incentive Compensation Plan for TECO Energy and subsidiaries, revised as of Feb. 2, 2011 (Exhibit 10.4, Form 10-K for 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.5	Form of Change-in-Control Severance Agreement between TECO Energy, Inc. and certain Executive Officers (Exhibit 10.1, Form 10-Q for the quarter ended Sep. 30, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.6	Form of Change-in-Control Severance Agreement between TECO Energy, Inc. and certain Executive Officers (Exhibit 10.1, Form 8-K dated Feb. 5, 2010 of TECO Energy, Inc.).	*
10.7	TECO Energy Directors' Deferred Compensation Plan, as amended and restated effective as of Aug. 1, 2007 (Exhibit 10.3, Form 10-Q for the quarter ended Sep. 30, 2007 of TECO Energy, Inc. and Tampa Electric Company).	*
10.8	Amendment No. 1 to TECO Energy Directors' Deferred Compensation Plan, effective as of Apr. 29, 2009 (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2009 of TECO Energy, Inc. and Tampa Electric Company).	*

Exhibit No.	Description	
10.9	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1996 Equity Incentive Plan (and its successor plan) (Exhibit 10.5, Form 10-Q for the quarter ended Jun. 30, 1999 of TECO Energy, Inc.).	*
10.10	TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.1, Form 8-K dated Apr. 16, 1997 of TECO Energy, Inc.).	*
10.11	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1997 Director Equity Plan, dated as of Jan. 29, 2003 (Exhibit 10.28, Form 10-K for 2002 of TECO Energy, Inc. and Tampa Electric Company).	*
10.12	TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
10.13	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Jun. 30, 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.14	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended Jun. 30, 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.15	Nonstatutory Stock Option granted to S. W. Hudson, dated as of Jul. 6, 2004, under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
10.16	TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.1, Post-Effective Amendment No. 1 to Form S-8 Registration Statement No. 333-115954 dated May 5, 2010 of TECO Energy, Inc.).	*
10.17	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.18	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.19	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain directors under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.4, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.20	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended March 31, 2013).	*
10.21	Compensatory Arrangements with Executive Officers of TECO Energy, Inc.	
10.22	Compensatory Arrangements with Non-Management Directors of TECO Energy, Inc.	
10.23		*

	Change-in-Control Severance Agreement between TECO Energy, Inc. and Clark Taylor (Exhibit 10.1, Form 10-Q for the quarter ended Mar. 31, 2011 of TECO Energy, Inc. and Tampa Electric Company).	
10.24	Change-in-Control Severance Agreement between TECO Coal Corporation and Clark Taylor (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.25	Retention Agreement dated as of August 14, 2014 with Clark Taylor (Exhibit 10.9, Form 10-Q for the quarter ended Sept. 31, 2014).	*
10.26	Voluntary Retirement Agreement and General Release between TECO Services, Inc. and Deirdre A. Brown dated as of Nov. 11, 2014.	
10.27	Separation Agreement and General Release between New Mexico Gas Company, Inc. and Annette Gardiner dated as of Dec. 1, 2014.	
10.28	Insurance Agreement dated as of Jan. 5, 2006 between Tampa Electric Company and Ambac Assurance Corporation (Exhibit 10.1, Form 8-K dated Jan. 19, 2006 of Tampa Electric Company).	*
10.29	Third Amended and Restated Credit Agreement dated as of Oct. 25, 2011, among TECO Finance, Inc., as Borrower, TECO Energy, Inc. as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 4.1, Form 8-K dated Oct. 25, 2011 of TECO Energy, Inc.).	*

Exhibit No.	Description	
10.30	Third Amended and Restated Credit Agreement dated as of Oct. 25, 2011, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 4.2, Form 8-K dated Oct. 25, 2011 of Tampa Electric Company).	*
10.31	Purchase and Contribution Agreement dated as of Jan. 6, 2005, between Tampa Electric Company as the Originator and TEC Receivables Corporation as the Purchaser (Exhibit 4.1, Form 8-K dated Jan. 6, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
10.32	Loan and Servicing Agreement dated as of Jan. 6, 2005, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 4.2, Form 8-K dated Jan. 6, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
10.33	Omnibus Amendment No. 3 to Loan and Servicing Agreement dated as of Dec. 22, 2006, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (also amending the agreement identified in Exhibit 10.29 herein) (Exhibit 10.28.1, Form 10-K for 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.34	Amendment No. 6 to Loan and Servicing Agreement dated as of Dec. 18, 2008, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 99.1, Form 8-K dated Dec.18, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.35	Amendment No. 8 to Loan and Servicing Agreement dated as of Feb. 19, 2010, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 10.28.3, Form 10-K for 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.36	Omnibus Amendment No. 9 to Loan and Servicing Agreement dated as of Feb. 18, 2011, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, N.A. as Program Agent (Exhibit 10.37, Form 10-K for 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.37	Amendment No. 10 to Loan and Servicing Agreement dated as of Feb. 17, 2012, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, N.A. as Program Agent (Exhibit 10.38, Form 10-K for 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.38	Amendment No. 11 to Loan and Servicing Agreement dated as of Feb. 15, 2013, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, N.A. as Program Agent (Exhibit 10.39, Form 10-K for 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
10.39	Omnibus Amendment No. 12 to Loan and Servicing Agreement dated as of Feb. 14, 2014, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, N. A. as Program Agent (Exhibit 10.37, Form 10-K for 2013 of TECO Energy, Inc. and Tampa Electric Company).	*

10.40	Amendment No. 13 to Loan and Servicing Agreement dated as of Feb. 3, 2015, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, N.A. as Program Agent.	
10.41	Senior Unsecured Bridge Credit Agreement, dated as of June 24, 2013, by and among TECO Energy, Inc., as Guarantor, TECO Finance, Inc., as Borrower, Morgan Stanley Senior Funding, Inc., as Administrative Agent, and the Lenders party thereto (Exhibit 10.1, Form 8-K dated June 28, 2013 of TECO Energy, Inc.).	*
10.42	Amendment No. 1 dated as of June 24, 2013 to the Third Amended and Restated Credit Agreement dated as of October 25, 2011, among TECO Finance, Inc., as Borrower, TECO Energy, Inc. as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.2, Form 8-K dated June 28, 2013 of TECO Energy, Inc.).	*
10.43	Fourth Amended and Restated Credit Agreement dated as of December 17, 2013, among TECO Finance, Inc., as Borrower, TECO Energy, Inc. as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 10.1, Form 8-K dated Dec. 17, 2013 of TECO Energy, Inc. and Tampa Electric Company).	*
10.44	Fourth Amended and Restated Credit Agreement dated as of December 17, 2013, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 10.2, Form 8-K dated Dec. 17, 2013 of TECO Energy, Inc. and Tampa Electric Company).	*
10.45	Credit Agreement dated as of December 17, 2013, among TECO Energy, Inc., as Initial Borrower JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 10.3, Form 8-K dated Dec. 17, 2013 of TECO Energy, Inc. and Tampa Electric Company).	*

Exhibit No.	Description	
10.46	Amendment No. 1, dated as of July 31, 2014, to the Senior Unsecured Bridge Credit Agreement, dated as of June 24, 2013, by and among TECO Finance, Inc., as Borrower, TECO Energy, Inc., as Guarantor, Morgan Stanley Senior Funding, Inc., as Administrative Agent, and the Lenders party thereto (Exhibit 10.1, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
10.47	Amendment No. 1, dated as of August 1, 2014, to the Fourth Amended and Restated Credit Agreement dated as of December 17, 2013, among TECO Finance, Inc., as Borrower, TECO Energy, Inc., as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.2, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
10.48	Amendment No. 1, dated as of August 1, 2014, to the Fourth Amended and Restated Credit Agreement dated as of December 17, 2013, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.3, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
10.49	Amendment No. 1, dated as of August 1, 2014, to the Credit Agreement dated as of December 17, 2013, among TECO Energy, Inc., as Initial Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.4, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
10.50	Joinder and Release Agreement, dated as of September 2, 2014, among TECO Energy, Inc., New Mexico Gas Company, Inc. and JPMorgan Chase Bank, N.A., as Administrative Agent, to the Credit Agreement dated as of December 17, 2013, as amended, among TECO Energy, Inc., as Initial Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.5, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
10.51	Amendment No. 2, dated as of September 30, 2014, to the Fourth Amended and Restated Credit Agreement dated as of December 17, 2013, as amended, among TECO Finance, Inc., as Borrower, TECO Energy, Inc., as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.6, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
10.52	Amendment No. 2, dated as of September 30, 2014, to the Fourth Amended and Restated Credit Agreement dated as of December 17, 2013, as amended, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.7, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
10.53	Amendment No. 2, dated as of September 30, 2014, to the Credit Agreement dated as of December 17, 2013, as amended, among New Mexico Gas Company, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.8, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company).	*
12.1	Ratio of Earnings to Fixed Charges – TECO Energy, Inc.	
12.2	Ratio of Earnings to Fixed Charges – Tampa Electric Company.	

21	Subsidiaries of TECO Energy, Inc.
23.1	Consent of Independent Certified Public Accountants – TECO Energy, Inc.
23.2	Consent of Independent Certified Public Accountants – Tampa Electric Company.
23.3	Consent of Cardno, Inc.
31.1	Certification of the Chief Executive Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.3	Certification of the Chief Executive Officer of Tampa Electric Company pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Certification of the Chief Financial Officer of Tampa Electric Company to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of the Chief Executive Officer and Chief Financial Officer of TECO Energy, Inc. pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)

Exhibit No.	Description
32.2	Certification of the Chief Executive Officer and Chief Financial Officer of Tampa Electric Company pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)
95	Mine Safety Disclosure
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

(1) This certification accompanies the Annual Report on Form 10-K and is not filed as part of it.

* Indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. Exhibits filed with periodic reports of TECO Energy, Inc. and Tampa Electric Company were filed under Commission File Nos. 1-8180 and 1-5007, respectively.

Certain instruments defining the rights of holders of long-term debt of TECO Energy, Inc. and its consolidated subsidiaries authorizing in each case a total amount of securities not exceeding 10% of total assets on a consolidated basis are not filed herewith. TECO Energy, Inc. will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Certain instruments defining the rights of holders of long-term debt of Tampa Electric Company authorizing in each case a total amount of securities not exceeding 10% of total assets on a consolidated basis are not filed herewith. Tampa Electric Company will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Executive Compensation Plans and Arrangements

Exhibits 10.1 through 10.27, above are management contracts or compensatory plans or arrangements in which executive officers or directors of TECO Energy, Inc. participate.