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March 30, 2017

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Application of Tampa Electric Company for authority to issue and sell securities pursuant to Section 366.04, F.S. and Chapter 25-8, F.A.C. during the twelve months ending December 31, 2016; Docket No. 150194-EI

Dear Ms. Stauffer:

Pursuant to Rule 25-8.009, Florida Administrative Code, and this Commission's Order No. PSC-15-0510-FOF-EI issued October 29, 2015, attached is Tampa Electric Company's Consummation Report regarding the issuance and sale of securities during the fiscal year ended December 31, 2016.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application of Tampa Electric Company	)	
For Authority to Issue and Sell Securities Pursuant	)	
To Section 366.04, F.S., and Chapter 25-8, F.A.C.	)	DOCKET NO. 150194-EI
During the Twelve Months Ending	)	FILED: March 30, 2017
December 31, 2016	)	
	)	

CONSUMMATION REPORT

The applicant, Tampa Electric Company (the "Company"), pursuant to Commission Order No. PSC-15-0510-FOF-EI dated October 29, 2015, submits the following information with respect to the issuance and/or sale of securities during the twelve months ending December 31, 2016.

Facts of Issues

The Company regularly borrows under its two revolving credit facilities, both of which permit the Company to draw down, repay and re-borrow funds. Given the frequency of these borrowings and repayments, it is not practicable to give the details of each action. However, the Company's borrowing activity in 2016 can be summarized as follows:

	($Millions)
Minimum Outstanding	$ 0
Maximum Outstanding	$ 170.0
Average Outstanding	$ 61.8
Weighted Average Interest Cost	1.17%

Statement of Capitalization

Statements of capitalization, pretax interest coverage, debt interest requirements and preferred stock dividend requirements of the Company for the year ending December 31, 2016 are as follows:

Capital Structure	($Millions)
Short-term Debt	$170.0
Long-term Debt (including amounts due within one year)	2,162.9
Preferred Stock	-
Common Equity	2,763.8
Total Capitalization	$5,096.7
Pretax Interest Coverage	
Including AFUDC	4.64 times
Excluding AFUDC	5.14 times
Debt Interest Requirements	$117.3
Preferred Stock Dividends	-

Respectfully submitted this 30th day of March, 2017

TAMPA ELECTRIC COMPANY

By: KM Caruso

Kim M. Caruso
Treasurer

Consummation Report
Exhibit List

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2016

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
1-5007	**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: NONE

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

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 ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
YES ☐ NO ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
YES ☒ NO ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
YES ☒ NO ☐

Indicate by check mark 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 registrant's 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. ☒

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	☒	Smaller reporting company	☐

Indicate by check mark whether Tampa Electric Company is a shell company (as defined in Rule 12b-2 of the Act).
YES ☐ NO ☒

The aggregate market value of Tampa Electric Company’s common stock held by non-affiliates of the registrant as of June 30, 2016 was zero.

As of February 8, 2017, 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.

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 receipts
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
CAIR	Clean Air Interstate Rule
CCRs	coal combustion residuals
CMO	collateralized mortgage obligation
CNG	compressed natural gas
CPI	consumer price index
CSAPR	Cross State Air Pollution Rule
CO_2	carbon dioxide
CT	combustion turbine
ECRC	environmental cost recovery clause
EEI	Edison Electric Institute
EGWP	Employee Group Waiver Plan
Emera	Emera Inc., a geographically diverse energy and services company headquartered in Nova Scotia, Canada
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act
EROA	expected return on plan assets
EUSHI	Emera US Holdings Inc., a wholly owned subsidiary of Emera, which is the sole shareholder of TECO Energy's common stock
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FPSC	Florida Public Service Commission
GHG	greenhouse gas(es)
HAFTA	Highway and Transportation Funding Act
HCIDA	Hillsborough County Industrial Development Authority
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)
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
Merger	Merger of Merger Sub Company with and into TECO Energy, with TECO Energy as the surviving corporation
MGP	manufactured gas plant
Merger Agreement	Agreement and Plan of Merger dated September 4, 2015, by and among TECO Energy, Emera and Merger Sub Company
Merger Sub Company	Emera US Inc., a Florida corporation
MMA	The Medicare Prescription Drug, Improvement and Modernization Act of 2003
MMBTU	one million British Thermal Units
MRV	market-related value
MW	megawatt(s)
MWH	megawatt-hour(s)
NAESB	North American Energy Standards Board

Term	Meaning
NAV	net asset value
NMGC	New Mexico Gas Company, Inc.
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
OPC	Office of Public Counsel
OPEB	other postretirement benefits
OTC	over-the-counter
PBGC	Pension Benefit Guarantee Corporation
PBO	postretirement benefit obligation
PGA	purchased gas adjustment
PGS	Peoples Gas System, the gas division of Tampa Electric Company
PPA	power purchase agreement
PPSA	Power Plant Siting Act
PRP	potentially responsible party
R&D	research and development
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
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
STIF	short-term investment fund
Tampa Electric	Tampa Electric, the electric division of Tampa Electric Company
TEC	Tampa Electric Company
TECO Energy	TECO Energy, Inc., the direct parent company of Tampa Electric Company
TSI	TECO Services, Inc.
U.S. GAAP	generally accepted accounting principles in the United States
VIE	variable interest entity
WRERA	The Worker, Retiree and Employer Recovery Act of 2008

PART I

Item 1. BUSINESS.

Tampa Electric Company, referred to as TEC, was incorporated in Florida in 1899 and was reincorporated in 1949. TEC is a public utility operating within the State of Florida. TEC has two operating segments. Its electric division, referred to as Tampa Electric, provides retail electric service to approximately 736,000 customers in West Central Florida with a net winter system generating capacity of 4,731 MW at December 31, 2016. The gas division of TEC, referred to as PGS, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With approximately 374,000 customers at December 31, 2016, 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 2016 was approximately 1.9 billion therms. TEC had approximately 2,600 employees as of December 31, 2016. All of TEC's common stock is owned by TECO Energy, a holding company for regulated utilities and other businesses.

TEC makes its SEC (www.sec.gov) filings available free of charge on TECO Energy's website (www.tecoenergy.com) 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 TEC 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.

Merger with Emera

On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on September 4, 2015. As a result of the Merger, the Merger Sub Company merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera. Therefore, TEC continues to be a wholly owned subsidiary of TECO Energy and became an indirect wholly owned subsidiary of Emera as of July 1, 2016. See **Note 8** to the **2016 Annual TEC Consolidated Financial Statements** for further information regarding the Merger.

TEC Revenues

(millions)	*2016*	*2015*	*2014*
Tampa Electric division	$ 1,964.5	$ 2,018.3	$ 2,021.0
PGS division	439.3	407.5	399.6
Eliminations	(8.0)	(6.6)	(1.6)
Total revenues	$ 2,395.8	$ 2,419.2	$ 2,419.0

TEC's residential load generally comprises individual homes, apartments and condominiums. Commercial customers include small retail operations, large office and commercial complexes, universities and hospitals. Industrial customers include manufacturing facilities and other large volume operations. Other sales volumes consist primarily of off-system sales to other utilities and revenues from street lighting.

For additional financial information regarding TEC's business segments, see **Note 11** to the **2016 Annual TEC Consolidated Financial Statements**.

TAMPA ELECTRIC – Electric Operations

TEC's 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. The principal communities served are Tampa, Temple Terrace, Winter Haven, Plant City and Dade City. Tampa Electric engages in wholesale sales to utilities and other resellers of electricity. It has two electric generating stations in or near Tampa and one electric generating station in southwestern Polk County, Florida.

Tampa Electric had 2,039 employees as of December 31, 2016, of which 819 were represented by the International Brotherhood of Electrical Workers and 168 were represented by the Office and Professional Employees International Union.

In 2016, Tampa Electric's total operating revenue was derived approximately 53% from residential sales, 30% from commercial sales, 8% from industrial sales and 9% from other sales, including bulk power sales for resale. The sources of operating revenue and MWH sales for the years indicated were as follows:

Tampa Electric Operating Revenue

(millions)	*2016*	*2015*	*2014*
Residential	$ 1,035.5	$ 1,040.3	$ 1,007.6
Commercial	593.4	608.0	602.0
Industrial	161.1	160.2	164.5
Other retail sales of electricity	174.4	177.2	181.9
Total retail	1,964.4	1,985.7	1,956.0
Sales for resale	6.3	3.7	13.0
Other	(6.2)	28.9	52.0
Total operating revenues	$ 1,964.5	$ 2,018.3	$ 2,021.0

Megawatt- hour Sales

(thousands)	*2016*	*2015*	*2014*
Residential	9,188	9,045	8,656
Commercial	6,310	6,301	6,142
Industrial	1,928	1,870	1,901
Other retail sales of electricity	1,808	1,791	1,827
Total retail	19,234	19,007	18,526
Sales for resale	206	115	259
Total energy sold	19,440	19,122	18,785

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, issuance 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 prudently incurred costs of providing service to customers, plus a reasonable return on invested capital.

The costs of owning, operating and maintaining the utility systems, excluding fuel, conservation costs, purchased power and certain environmental costs for the electric system, are recovered through base rates. These costs include O&M expenses, depreciation, taxes, and 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 a 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 the past three years reflect the results of a Stipulation and Settlement Agreement entered into on September 6, 2013, between Tampa Electric and the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric's 2013 base rate proceeding. On September 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 November 1, 2013, an additional $7.5 million effective November 1, 2014, an additional $5.0 million effective November 1, 2015, and an additional $110.0 million effective the date that an expansion of Tampa Electric's Polk Power Station went into service, which was January 16, 2017. The agreement also 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 base rate increases to be effective sooner than January 1, 2018, unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE were increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE were increased as described above) any party to the agreement other than Tampa Electric could seek a review of its base rates. In addition, Tampa Electric 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. 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 beginning on January 1, 2013.

Tampa Electric's storm reserve was $56.1 million at both December 31, 2016 and 2015. Tampa Electric ceased accruing $8.0 million annually to the FPSC-approved self-insured storm damage reserve effective November 1, 2013. 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 of the reserve as of October 31, 2013. As a result of several named storms including Tropical Storm Colin, Hurricane Hermine and Hurricane Matthew, Tampa Electric has incurred $8.6 million of storm costs in 2016. On January 31, 2017, Tampa Electric petitioned the FPSC to seek full recovery of those costs as a surcharge to customers during the five-month period ended December 31, 2017.

Tampa Electric has a fuel recovery clause, approved by the FPSC, allowing recovery of actual fuel costs from customers through annual fuel rate adjustments. Differences between actual prudently incurred fuel costs and amounts recovered from customers through electricity rates in a year are deferred to a fuel clause regulatory asset or liability and recovered from or returned to customers in a subsequent year. Tampa Electric has an environmental cost recovery clause which allows it to earn a return on investments in new facilities to comply with new environmental regulations and to recover the costs to operate and maintain these facilities. Through its conservation cost recovery clause, Tampa Electric also offers its customers a comprehensive array of residential and commercial programs that have enabled it to meet its required demand side management goals, reduce weather-sensitive peak demand and conserve energy. In November 2016, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2017.

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 affiliate, TSI (TECO Energy's centralized service company), 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, respectively. Given TECO Energy's (TEC's parent) acquisition of NMGC in 2014, Tampa Electric and TECO Energy jointly requested a waiver from FERC in order to continue to supply a de-minimis level of non-power goods and services to affiliates, which the FERC granted without conditions effective as of January 1, 2015. Through TSI, TECO Energy provides TEC with specialized services at cost, including information technology, procurement, human resources, legal, risk management, financial, and administrative services. For additional information regarding TSI, see **Note 10** to the **2016 Annual TEC Consolidated Financial Statements**.

On June 30, 2014, Tampa Electric filed its required triennial market-power analysis in support of the company's continued ability to effect wholesale market-based rate transactions everywhere, except in Tampa Electric's balancing-authority area. FERC accepted Tampa Electric's filing on November 24, 2015. Tampa Electric will file its next triennial market power analysis with FERC by June 30, 2017.

Tampa Electric is also subject to federal, state and local environmental laws and regulations pertaining to air and 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 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. Tampa Electric intends to retain and expand its retail business by managing costs and providing quality service to retail customers.

Unlike in the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including approximately 30 other utilities as well as other power generators. 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. 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.

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. Developers offer attractive financing and leasing arrangements to encourage project development. In Florida, third parties that are not subject to regulation by the FPSC are currently not permitted to make direct sales of electricity to end-use customers. See the **Solar Initiative** section of the **MD&A**.

Fuel

Approximately 56% of Tampa Electric's generation of electricity for 2016 was natural gas-fired, with coal representing approximately 38% and oil/petroleum coke representing 6%. Tampa Electric used its generating units to meet approximately 87% of the total system load requirements, with the remaining 13% coming from purchased power. Tampa Electric is required to maintain a generation capacity greater than firm peak demand. Tampa Electric meets the planning criteria for reserve capacity established by the FPSC, which is a 20% reserve margin over firm peak demand.

Tampa Electric's average delivered fuel cost per MMBTU and average delivered cost per unit of coal burned have been as follows:

Average cost per MMBTU	*2016*	*2015*	*2014*
Natural Gas (1)	$ 3.79	$ 4.34	$ 5.68
Coal (2)	3.61	3.44	3.58
Oil (3)	2.14	2.36	2.66
Composite (4)	3.61	3.78	4.16
Average cost per ton of coal burned	$ 85.38	$ 80.83	$ 84.40

(1) Represents the cost of natural gas, transportation, storage, balancing, hedges for the price of natural gas, and fuel losses for delivery to the energy center.
(2) Represents the cost of coal and transportation.
(3) Represents the cost of oil, including petroleum coke.
(4) Represents the average cost for all fuels listed.

Tampa Electric's fuel costs are affected by commodity prices and generation mix that is largely dependent on economic dispatch of the generating fleet, dispatching the lowest cost options first (after solar renewable energy), such that the incremental cost of generation increases as sales volumes increase. Generation mix may also be affected by plant outages, plant performance, availability of lower priced short-term purchased power, and compliance with environmental standards and regulations.

In 2016, Tampa Electric's generating stations burned fuels as follows: Bayside Station burned natural gas; Big Bend Station, which has SO_2 scrubber capabilities and NO_x reduction systems, burned natural gas and a combination of high-sulfur coal and petroleum coke; and Polk Power Station burned a blend of low-sulfur coal and petroleum coke (which was gasified and subject to sulfur and particulate matter removal prior to combustion), natural gas and oil.

Natural Gas. As of December 31, 2016, approximately 66% of Tampa Electric's 1,500,000 MMBTU gas storage capacity was full. Tampa Electric has contracted for 84% of its expected gas needs for the April 2017 through October 2017 period. In early March 2017, Tampa Electric expects to issue RFPs to meet its remaining 2017 gas needs and begin contracting for its 2018 requirements. Additional volume requirements in excess of projected gas needs are purchased on the short-term spot market.

The combined cycle unit at the Polk Power Station began commercial operations in January 2017. Existing natural gas supplies and interstate pipeline capacity are sufficient to support its operations.

Coal. Tampa Electric burned approximately 3.0 million tons of coal during 2016 and estimates that its coal consumption will be about 3.6 million tons in 2017. During 2016, Tampa Electric purchased approximately 94% of its coal under long-term contracts with four suppliers, and approximately 6% of its coal in the spot market. Tampa Electric expects to obtain approximately 56% of its coal requirements in 2017 under long-term contracts with four suppliers and the remaining 44% in the spot market. Tampa Electric has coal transportation agreements with trucking, rail, barge and ocean vessel companies.

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 2016, approximately 96% of Tampa Electric's coal supply was deep-mined and approximately 4% was surface-mined. 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.

Oil. Tampa Electric purchases low sulfur No. 2 fuel oil and petroleum coke for its Big Bend and Polk Power stations on a spot basis.

Franchises and Other Rights

Florida utilities must obtain franchises to operate in certain municipalities. 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 that 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 2017. 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 ranging from September 2017 through August 2043 and are expected to be renewed under similar terms and conditions.

Franchise fees expense totaled $46.5 million in 2016 and 2015. Franchise fees are calculated using a formula based primarily on electric revenues and are recovered from customers on a dollar-for-dollar basis.

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. Its operations are also impacted by provisions in the Clean Water Act and federal and state legislative initiatives on environmental matters. 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.

Tampa Electric's 2016 capital expenditures included approximately $11 million related to environmental compliance and improvement programs, primarily for scrubber improvements, SCR catalyst replacements and electrostatic precipitators at the Big Bend Power Station. See the **Liquidity-Capital Investments** section of the **MD&A** for additional information on estimated future capital expenditures.

PEOPLES GAS SYSTEM – Gas Operations

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 distribution 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 approximately 370,000 customers. The system includes approximately 12,400 miles of mains and 7,000 miles of service lines (see PGS's **Franchises and Other Rights** section below). Gas mains are distribution lines that serve as a common source of supply for more than one service line.

PGS had 539 employees as of December 31, 2016. A total of 140 employees in five of PGS's 14 operating divisions and call center are represented by various union organizations.

In 2016, the total throughput for PGS was approximately 1.9 billion therms. Of this total throughput, 5% was gas purchased and resold to customers by PGS, 82% was third-party supplied gas that was delivered to transportation-only customers and 13% was gas sold off-system (i.e., to customers not connected to PGS's distribution system). Industrial and power generation customers consumed approximately 57% of PGS's annual therm volume, commercial customers consumed approximately 26%, off-system sales customers consumed 13% and the remaining balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, approximately 33% of total revenues were from residential customers in 2016.

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 44 compressed natural gas filling stations connected to the PGS distribution system. See the **Outlook** and **PGS Operating Results** sections of the **MD&A** for information on the impact of natural gas vehicles on PGS's operations.

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

	Revenues			**Therms**		
(millions)	*2016*	*2015*	*2014*	*2016*	*2015*	*2014*
Residential	$ 139.7	$ 137.0	$ 144.1	77.6	74.9	80.8
Commercial	142.7	138.8	139.1	488.3	470.8	460.5
Industrial	13.6	13.0	13.1	321.0	289.0	274.3
Off-system sales	72.7	49.8	39.4	245.1	166.4	84.0
Power generation	5.3	7.2	6.8	759.5	758.3	643.5
Other revenues	52.8	50.5	48.5			
Total	$ 426.8	$ 396.3	$ 391.0	1,891.5	1,759.4	1,543.1

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 to collect total revenues (revenue requirements) equal to its prudently incurred costs of providing service to customers, 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.

PGS's results reflect base rates established in May 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.

On June 28, 2016, PGS filed its depreciation study with the FPSC seeking approval for new depreciation rates. After communications with the FPSC staff, on December 15, 2016, PGS and OPC filed a settlement with the FPSC agreeing to new depreciation rates that reduce annual depreciation expense by $16.1 million in 2016, accelerate the amortization of the regulatory asset associated with environmental remediation costs as described below, include obsolete plastic pipe replacements through the existing cast iron and bare steel replacement rider, and decrease the bottom of the ROE range from 9.75% to 9.25%. The new bottom of the range will remain until the earlier of new base rates established in PGS's next general base rate proceeding or December 31, 2020. The top of the range will continue to be 11.75%, and the ROE of 10.75% will continue to be used for the calculation of return on investment for clauses and riders. On February 7, 2017, the FPSC approved the settlement agreement. No change in customer rates resulted from this agreement.

As part of the settlement, PGS and OPC agreed that at least $32 million of PGS's regulatory asset associated with the environmental liability for current and future remediation costs related to former MGP sites, to the extent expenses are reasonably and prudently incurred, will be amortized over the period 2016 through 2020. At least $21 million will be amortized over a two-year recovery period beginning in 2016. In 2016, PGS recorded $16 million of this amortization expense.

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 actual costs incurred by PGS 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. 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 2016, the FPSC approved PGS's 2017 PGA cap factor for the period January 2017 through December 2017.

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 as mentioned above. 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 recover the return on, depreciation expenses and applicable taxes associated with the replacement of cast iron/bare steel infrastructure. The FPSC approved a replacement program of approximately 5%, or 500 miles, of the PGS system at a cost of approximately $80 million over a 10-year period beginning in 2013. As disclosed above, in February 2017, the FPSC approved an amendment to the eligible replacements under the existing cast iron bare steel rider to include certain plastic materials and pipe deemed obsolete by Pipeline Safety and Hazardous Materials Administration, totaling approximately 1,000 miles. PGS projects to have all cast iron and bare steel pipe removed from its system by 2022, with the replacement of obsolete plastic pipe continuing until 2028 under the rider.

The FPSC also 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 offers unbundled transportation service to all non-residential customers, and 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. 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 affect when a customer shifts to transportation-only sales. 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 24,400 transportation-only customers as of December 31, 2016 out of approximately 37,600 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.

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 contracts and swing-supply contracts (i.e., short-term contracts without a specified volume) 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.

Franchises and Other Rights

PGS holds franchise and other rights with 116 municipalities and districts 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 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 have various expiration dates ranging from 2017 through 2044. PGS expects to negotiate ten franchises in 2017. Franchise fees expense totaled $9.5 million in 2016. Franchise fees are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are recovered on a dollar-from-dollar basis from only those customers within each franchise area.

Utility operations in areas outside of incorporated municipalities and districts 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 MGP sites. See **Note 9** to the **2016 Annual TEC Consolidated Financial Statements** and the **Environmental Compliance** section of the **MD&A** for additional information.

During the year ended December 31, 2016, PGS did not incur any material capital expenditures to meet environmental requirements as none were required, nor are any anticipated for the 2017 through 2021 period.

EXECUTIVE OFFICERS OF THE REGISTRANT

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

Name	Age	Current Positions and Principal Occupations During The Last Five Years
Gordon L. Gillette	56	President, TEC, July 2009 to date; and Chief Executive Officer, TEC, September 2016 to date.
Gregory W. Blunden	52	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TEC, September 2016 to date; Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TECO Energy, September 2016 to date; Chief Financial Officer, Emera, March 2016 to date; Vice President, Corporate Strategy & Planning, Emera, July 2015 to February 2016; Executive Vice President, Customer, Business & Financial Services, Nova Scotia Power Inc., January 2014 to June 2015; Vice President, Business Development, Emera, April 2012 to December 2013; and Vice President, Business Development, Bangor Hydro Electric Company (now Emera Maine, a subsidiary of Emera), June 2009 to March 2012.
Thomas J. Szelistowski	56	President, PGS, August 2016 to date; Vice President-Gas Delivery, TEC, January 2016 to August 2016; Managing Director of Regulatory Affairs, TEC, March 2011 to January 2016; and Director of Energy Delivery, Engineering and Operational Services of TEC, February 2010 to March 2011.

There is no family relationship between any of the persons named above or between executive officers and any director of TEC. The term of office of each officer extends until such officer's successor is elected and qualified.

Item 1A. RISK FACTORS.

General Risks

National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at TEC.

The business of TEC is concentrated in Florida. If economic conditions start to decline, retail customer growth rates may stagnate or decline, and customers' energy usage may further decline, adversely affecting TEC's results of operations, net income and cash flows. A factor in our customer growth in Florida is net in migration of new residents, both domestic and non-U.S. A slowdown in the U.S. economy could reduce the number of new residents and slow customer growth.

Developments in technology could reduce demand for electricity and gas.

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, energy efficiency and more energy-efficient appliances and equipment. Advances in these or other technologies could reduce the cost of producing electricity or transporting gas, or otherwise make the existing generating facilities of Tampa Electric uneconomic. In addition, advances in such technologies could reduce demand for electricity or natural gas, which could negatively impact the results of operations, net income and cash flows of TEC.

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

For the past several years, at Tampa Electric and electric utilities across the United States, weather-normalized electricity consumption per residential customer has declined due to the combined effects of voluntary conservation efforts, economic conditions and improvements in lighting and appliance efficiency.

Forecasts by TEC are based on normal weather patterns and historical trends in customer energy-usage patterns. The ability of TEC 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.

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

TEC's utility businesses are affected by variations in general weather conditions and unusually severe weather. Energy sales by its electric and gas utilities are particularly sensitive to seasonal variations in weather conditions, including unusually mild summer or winter weather that cause lower energy usage for cooling or heating purposes, respectively. Tampa Electric and PGS 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, which typically has a short but significant winter peak period that is dependent on cold weather, is more weather-sensitive than Tampa Electric, which has both summer and winter peak periods. Mild winter weather could negatively impact results at TEC.

TEC's electric and gas utilities are regulated; changes in regulation or the regulatory environment could reduce revenues, increase costs or competition.

TEC's electric and gas utilities operate in regulated industries. Retail operations, including the prices charged, are regulated by the FPSC, 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 TEC's 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, indicating an overearnings trend, those earnings could be subject to review by the FPSC. Ultimately, prolonged overearnings could result in credits or refunds to customers, which could reduce earnings and cash flow.

Increased customer use of distributed generation could adversely affect Tampa Electric.

In many areas of the United States, 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.

Increased usage of distributed generation, can reduce utility electricity sales but does not reduce the need for ongoing investment in infrastructure to maintain or expand the transmission and distribution grid to reliably serve customers. Continued utility investment that is not supported by increased energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

Potential changes in solar energy could adversely impact Tampa Electric.

In 2015, there was a proposed constitutional ballot initiative for the 2016 election approved by the Florida Supreme Court to promote increased direct sale and use of solar energy to generate electricity. Not enough signatures were collected for it to qualify for the 2016 ballot. It may be placed on the 2018 ballot if sufficient signatures are collected. A constitutional amendment was approved on the August 2016 primary election ballot that, subject to legislative action, will allow property exemptions for renewal energy devices used in commercial applications.

TEC anticipates enactment of legislation that would encourage the use of solar energy by retail customers and third parties, and could potentially 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 be compelled to make investments in facilities to serve customers who will move to use solar energy when solar energy becomes available to them, so that those investments may not be profitable over the long term.

Changes in the environmental laws and regulations affecting its businesses could increase TEC's costs or curtail its activities.

TEC's 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 TEC, requiring cost-recovery proceedings and/or requiring it to curtail some of its businesses' activities.

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

EPA's new CCR rule became effective on October 19, 2015. This rule regulates CCRs as non-hazardous solid waste and required Tampa Electric to begin incurring O&M and capital expenses in 2016 to achieve compliance. However, these expenses were recoverable under the Florida Environmental Cost Recovery Clause (ECRC), as approved by the Florida Public Service Commission (PSC) on February 2, 2016. Similarly, future expenses would be eligible for recovery upon petition by Tampa Electric and approval by the PSC.

On December 10, 2016, Congress passed the "Water Infrastructure Improvements for the Nation Act" (WIINA), which includes provisions modifying the implementation plan for the federal CCR Rule. WIINA amends the CCR Rule so that it will now be administered primarily by the states through state-operated permit programs which will be approved and overseen by the EPA. While this change should effectively eliminate the threat of litigation by private citizens as an enforcement mechanism by placing compliance and enforcement authority in the hands of the state agencies, Tampa Electric cannot ultimately be assured that any increased costs associated with the new regulations will be eligible for favorable cost-recovery treatment.

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

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 Tampa Electric cannot be assured that the FPSC would grant such recovery.

On February 9, 2016, the U.S. Supreme Court issued a stay against enforcement of the Clean Power Plan for the electricity sector pending resolution of the legal challenges before the U.S. Court of Appeals for the District of Columbia Circuit. The timing of the resolution of the legal challenges and the removal of the stay by the U.S. Supreme Court is uncertain, but it is likely to delay further actions by the states until 2018 or later.

Prior to the stay, the Clean Power Plan would have required each state to be responsible for implementing its own regulations to accord to the federal standards. Accordingly, a change in Florida's regulatory landscape could significantly increase Tampa Electric's costs. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on Tampa Electric requiring FPSC cost recovery proceedings and/or requiring it to curtail some of its business activities.

The Clean Power Plan would have established state-specific emission rate- and mass-based goals measured against a 2012 baseline. As Tampa Electric's investments in lower-GHG production largely occurred before 2012 and are factored into Florida's baseline generating capacity, if the Clean Power Plan moves forward, Tampa Electric may encounter more difficulty than its competitors in achieving cost-effective GHG emission reductions. Because the ultimate form of Florida's state plan remains unknown, the increased compliance costs that Tampa Electric may face as a result of the Clean Power Plan in its form prior to the stay are currently uncertain.

TEC's computer systems and the infrastructure of its utility companies are 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 its business and financial results and condition.

There have been an increasing number of cyberattacks 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.

TEC has 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, TEC cannot be assured that a cyberattack will not cause electric or gas system operational problems, property damage, customer information to be stolen, private information to be accessed, disruptions of service to customers, or important data or systems to be compromised. In addition, a cyberattack could subject TEC to additional regulation, litigation or damage to its reputation, which could result in loss of revenues and increased costs, including the costs incurred to repair and restore systems and the implementation of additional security measures.

There have also been physical attacks on critical infrastructure around the world. While the transmission and distribution system infrastructure of TEC's utility companies are designed and operated in a manner intended 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 and restore systems. These types of events, either impacting TEC's facilities or the industry in general, could also cause TEC to incur additional security- and insurance-related costs, and could have adverse effects on its business and financial results.

Potential competitive changes may adversely affect TEC.

There is competition in wholesale power sales across the United States. 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 a number of years. Gas services provided by PGS are unbundled for all non-residential customers. Because PGS earns margins on distribution of gas but not on the commodity itself, unbundling has not negatively impacted PGS's results. However, future structural changes could adversely affect PGS.

TEC relies on some natural gas transmission assets that it does not own or control to deliver natural gas. If transmission is disrupted, or if capacity is inadequate, TEC's ability to sell and deliver natural gas and supply natural gas to its customers and its electric generating stations may be hindered.

TEC depends on transmission facilities owned and operated by other utilities and energy companies to deliver the natural gas it sells to the wholesale and retail markets. If transmission is disrupted, or if capacity is inadequate, its ability to sell and deliver products and satisfy its contractual and service obligations could be adversely affected.

Disruption of fuel supply could have an adverse impact on the financial condition of TEC.

Tampa Electric and PGS depend on third parties to supply fuel, including natural gas, oil and coal. As a result, there are risks of supply interruptions and fuel-price volatility. Disruption of fuel supplies or transportation services for fuel, whether because of weather-related problems, strikes, lock-outs, break-downs of transportation facilities, pipeline failures or other events, could impair the ability to deliver electricity and gas or generate electricity and could adversely affect operations. The loss of coal suppliers or the inability to renew existing coal and natural gas contracts at favorable terms could significantly affect the ability to serve customers and have an adverse impact on the financial condition and results of operations of TEC.

Commodity price changes may affect the operating costs and competitive positions of TEC's businesses.

TEC's businesses are sensitive to changes in gas, coal, oil and other commodity prices. Any changes in the availability of these commodities could affect the prices charged by suppliers as well as suppliers' operating costs and the competitive positions of their products and services.

In the case of Tampa Electric, fuel costs used for generation are affected primarily by the cost of natural gas and coal. 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 of, 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, 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 as compared to electricity, other forms of energy and other gas suppliers.

The facilities and operations of TEC could be affected by natural disasters or other catastrophic events.

TEC's facilities and operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g. floods, high winds, fires and earthquakes), equipment failures, vandalism, potentially catastrophic events such as the occurrence of a major accident or incident at one of the sites, and other events beyond the control of TEC. The operation of transmission and distribution systems involves certain risks, including gas leaks, fires, explosions, pipeline ruptures and other hazards and risks that may cause unforeseen interruptions, personal injury or property damage. Any such incident could have an adverse effect on TEC and any costs relating to such events may not be recoverable through insurance or recovered in rates. In certain cases, there is potential that such an event may not excuse TEC's utility companies from servicing customers as required by their respective tariffs.

The franchise rights held by TEC's utilities could be lost in the event of a breach by such TEC utilities or could expire and not be renewed.

TEC's utilities hold franchise agreements with counterparties throughout their service areas. In some cases, these rights could be lost in the event of a breach of these agreements by the applicable TEC utility. In addition, these agreements are for set periods and could expire and not be renewed upon expiration of the then-current terms. Some agreements also contain provisions allowing municipalities to purchase the portion of the applicable utility's system located within a given municipality's boundaries under certain conditions.

Tampa Electric and PGS may not be able to secure adequate rights-of-way to construct transmission lines, gas interconnection lines and distribution-related facilities and could be required to find alternate ways to provide adequate sources of energy and maintain reliable service for their customers.

Tampa Electric and PGS rely on federal, state and local governmental agencies to secure rights-of-way and siting permits to construct transmission lines, gas interconnection lines and distribution-related facilities. If adequate rights-of-way and siting permits to build new transportation and transmission lines cannot be secured, then Tampa Electric and PGS:

- May need to remove or abandon its facilities on the property covered by rights of way or franchises and seek alternative locations for its transmission or distribution facilities;
- May need to rely on more costly alternatives to provide energy to their customers;
- May not be able to maintain reliability in their service areas; and/or
- May experience a negative impact on their ability to provide electric or gas service to new customers.

Failure to attract and retain an appropriately qualified workforce could adversely affect TEC's financial results.

Events such as increased retirements due to an aging workforce or the departure of employees for other reasons without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, including with the workforce needs associated with major construction projects and ongoing operations. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may cause costs to operate TEC's systems to rise and may adversely affect TEC's ability to manage and operate its business. If TEC is unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

TEC has indebtedness which could adversely affect its financial condition and financial flexibility.

TEC has indebtedness which results in fixed charges it is obligated to pay. The level of TEC's indebtedness and restrictive covenants contained in its debt obligations could limit its ability to obtain additional financing (see **Management's Discussion & Analysis – Significant Financial Covenants** section).

TEC must meet certain financial covenants as defined in the applicable agreements to borrow under its credit facilities. Also, TEC has certain restrictive covenants in specific agreements and debt instruments.

Although TEC was in compliance with all required financial covenants as of December 31, 2016, it cannot assure compliance with these financial covenants in the future. TEC's failure to comply with any of these covenants or to meet its 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. TEC may not have sufficient working capital or liquidity to satisfy its debt obligations in the event of an acceleration of all or a portion of its outstanding obligations. If TEC's cash flows and capital resources are insufficient to fund its debt service obligations, it may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance its indebtedness. TEC's ability to restructure or refinance its debt will depend on the condition of the capital markets and TEC's financial condition at such time. Any refinancing of TEC's debt could be at higher interest rates and may require compliance with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict TEC from adopting some of these alternatives.

TEC also incurs obligations that do not appear on its balance sheet, such as leases and letters of credit.

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

TEC has debt maturing in 2018 and subsequent years, which may need to be refinanced. Future financial market conditions could limit TEC's ability to raise the capital it needs and could increase its interest costs, which could reduce earnings. If TEC is not able to issue new debt, or TEC issues debt at interest rates higher than expected, its financial results or condition could be adversely affected.

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

TEC is a participant in the comprehensive retirement plans of TECO Energy. Under calculation requirements of the Pension Protection Act, as of the January 1, 2017 measurement date, TECO Energy's pension plan was fully funded. Under MAP 21, TEC is not required to make additional cash contributions over the next five years; however, TEC 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 its pension plan in the future, and could cause pension expense to increase.

TEC's financial condition and results could be adversely affected if its capital expenditures are greater than forecast.

For 2017, Tampa Electric is forecasting capital expenditures 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 and to maintain generating unit reliability and efficiency. For 2017, PGS is forecasting capital expenditures to support customer growth, system reliability, conversion of customers from other fuels to natural gas and to replace bare steel, cast iron and obsolete plastic pipe.

Total costs may be higher than estimated and there can be no assurance that TEC will be able to recover such expenditures through regulated rates. If TEC's capital expenditures exceed the forecasted levels, it may need to draw on credit facilities or access the capital markets on unfavorable terms. TEC cannot be sure that it will be able to obtain additional financing, in which case its financial position could be adversely affected.

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

The senior unsecured debt of TEC is rated by S&P at 'BBB+', by Moody's at 'A3' and by Fitch at 'A-'. A downgrade to below investment grade by the rating agencies, which would require a four-notch downgrade by Moody's and Fitch, and a three-notch downgrade by S&P, may affect TEC's ability to borrow, may change requirements for future collateral or margin postings, and may increase financing costs, which may decrease earnings. TEC may also experience greater interest expense than it would have otherwise if, in future periods, it replaces maturing debt with new debt bearing higher interest rates due to any downgrades. In addition, downgrades could adversely affect TEC's relationships with customers and counterparties.

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

Item 2. PROPERTIES.

TEC 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 2016 net winter generating capability of 4,731 MW. Tampa Electric assets include the Big Bend Power Station (1,632 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). On January 16, 2017, the combined cycle unit at the Polk Power Station was placed in service and expanded the plant by approximately 460 MW. See the **Tampa Electric – Polk Power Station Units 2-5 Combined Cycle Conversion** section of the **MD&A** for information regarding this project.

Tampa Electric has two solar arrays which went into service in 2015 and 2016 at Tampa International Airport (2 MW capacity) and LEGOLAND Florida (1.8 MW capacity), respectively. Tampa Electric is installing a 23 MW solar array at the Big Bend Power Station, which is expected to be placed in service in February 2017.

Tampa Electric owns 180 substations having an aggregate transformer capacity of 22,621 mega volts amps. The transmission system consists of approximately 1,330 total circuit miles of high voltage transmission lines, including underground and double-circuit lines that share poles or trenches. The distribution system consists of approximately 6,260 circuit miles of overhead lines and approximately 5,150 circuit miles of underground lines. As of December 31, 2016, there were 757,100 meters in service. All of this property is located in Florida.

All plants and important fixed assets are owned by Tampa Electric except that titles to some of the properties are subject to easements, leases, contracts, covenants and similar encumbrances 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.

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

PEOPLES GAS SYSTEM

PGS's distribution system extends throughout the areas it serves in Florida and consists of approximately 19,400 miles of pipe, including approximately 12,400 miles of mains and 7,000 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.

Item 3. LEGAL PROCEEDINGS.

From time to time, TEC is 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 TEC'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 **Note 9**, **Commitments and Contingencies**, of the **2016 Annual TEC Consolidated Financial Statements**.

PART II

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

All of TEC's common stock is owned by TECO Energy, which in turn is owned by a subsidiary of Emera and, thus, is not listed on a stock exchange. Therefore, there is no market for such stock. Dividends are declared and paid at the discretion of TEC's Board of Directors to maintain TEC's targeted capital structure. In 2016, 2015 and 2014, TEC paid quarterly dividends on its common stock substantially equal to its net income (see the **Consolidated Statements of Cash Flows** in the **2016 Annual TEC Consolidated Financial Statements**).

Item 6. SELECTED FINANCIAL DATA OF TAMPA ELECTRIC COMPANY

(millions) *Years ended December 31,*	*2016*	*2015*	*2014*	*2013*	*2012*
Revenues	$ 2,395.8	$ 2,419.2	$ 2,419.0	$ 2,342.8	$ 2,378.0
Net income	285.7	276.3	260.3	225.6	227.2
Total assets (1)	8,082.6	7,708.6	7,257.5	6,861.0	6,728.5
Long-term debt, including current portion (1)	2,162.9	2,245.0	2,080.3	1,866.0	1,916.5
Dividends paid (2)	288.2	268.4	262.6	222.1	228.3

(1) Amounts shown include reclassifications to reflect the accounting pronouncement adopted in 2016 related to debt issuance costs as discussed in **Note 2** to the **2016 Annual TEC Consolidated Financial Statements.**

(2) All of TEC's common stock is owned by TECO Energy as discussed in **Item 5.**

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 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.

In this Management's Discussion & Analysis, "we," "our," "ours" and "us" refer to TEC, unless the context otherwise requires.

OVERVIEW

TEC has regulated electric and gas utility operations in Florida. Tampa Electric served approximately 736,000 customers in a 2,000-square-mile service area in West Central Florida and had electric generating plants with a winter peak generating capacity of 4,731 MW at December 31, 2016. PGS, Florida's largest gas distribution utility, served approximately 374,000 residential, commercial, industrial and electric power generating customers at December 31, 2016 in all major metropolitan areas of the state, with a total natural gas throughput of approximately 1.9 billion therms in 2016.

MERGER WITH EMERA

TEC is a wholly owned subsidiary of TECO Energy. On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on September 4, 2015. As a result of the Merger, the Merger Sub Company merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera. Therefore, TEC continues to be a wholly owned subsidiary of TECO Energy and became an indirect wholly owned subsidiary of Emera as of July 1, 2016. The acquisition method of accounting was not pushed down to TECO Energy or its subsidiaries, including TEC. See **Notes 8 and 10** to the **2016 Annual TEC Consolidated Financial Statements** for further information regarding the Merger and related party transactions between TEC and its affiliates, respectively.

2016 PERFORMANCE

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

In 2016, our net income was $285.7 million, compared with $276.3 million in 2015. The most significant factors impacting the year-over-year-comparison of net income were higher base revenues driven by customer growth and a strong economy, higher AFUDC due to the construction of the Polk conversion project, and lower taxes primarily due to tax benefits related to AFUDC-equity and federal R&D tax credits, partially offset by higher O&M expense and depreciation expense.

OUTLOOK

Our earnings are most directly impacted by the earned rate of return on equity and the capital structure approved by the FPSC, the prudent management of operating costs, the approved recovery of regulatory deferrals, and the timing and amount of capital expenditures.

Tampa Electric and PGS anticipate earning within their allowed ROE ranges in 2017 and expect rate base and earnings to be higher than in prior years. Tampa Electric and PGS expect slightly higher customer growth rates in 2017 than those experienced in 2016, reflective of the economic growth in Florida. Assuming normal weather, sales are expected to increase primarily due to customer growth. Under a 2013 settlement agreement with the FPSC, Tampa Electric’s base rates increased by $110 million effective January 2017. This base rate increase will be more than offset in customer rates by a reduction in fuel expense in 2017. Depreciation expense is expected to increase in 2017 as the Polk unit was placed in service and from continued capital investments in facilities to reliably serve customers. In February 2017, the FPSC approved a settlement agreement filed by PGS and OPC, which resulted in a $16 million annual reduction to PGS’s depreciation expense beginning in 2016, which was offset by the acceleration of amortization of the regulatory asset associated with MGP environmental remediation costs. The MGP amortization from 2016 through 2020 will be at least $32 million, which includes $16 million recorded in 2016. Absent any base rate case filing, through 2020 PGS’s bottom of the allowed ROE range will be decreased 50 basis points to 9.25% and the top of the range will continue to be 11.75%. In addition, the ROE of 10.75% will continue to be used for the calculation of return on investment for clauses and riders. No change in customer rates resulted from this order. See **Note 3** to the **2016 Annual TEC Consolidated Financial Statements** for further information on the settlement agreement.

In 2017, we expect to invest approximately $550 million in capital projects compared to $727 million in 2016. This reduction is a result of the Polk Power Station being completed in January 2017. These include capital expenditures to support normal system reliability and growth at Tampa Electric and PGS; the programs for Tampa Electric transmission and distribution system storm hardening and transmission system reliability requirements; utility scale solar photo voltaic projects at Tampa Electric; and incremental investments above normal maintenance capital to expand the PGS system.

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

OPERATING RESULTS

This MD&A utilizes TEC’s consolidated financial statements, which have been prepared in accordance with U.S. GAAP. Our reported operating results are affected by a number of critical accounting estimates such as those involved in our accounting for regulated activities, deferred taxes, postretirement benefits and others (see the **Critical Accounting Policies and Estimates** section).

The following table shows the revenues and net income of the business segments on a U.S. GAAP basis (see **Note 11** to the **2016 Annual TEC Consolidated Financial Statements**).

(millions)	***2016***	*2015*	*2014*
Segment revenues			
Tampa Electric	$ 1,964.5	$ 2,018.3	$ 2,021.0
PGS	439.3	407.5	399.6
Eliminations	(8.0)	(6.6)	(1.6)
	$ 2,395.8	$ 2,419.2	$ 2,419.0
Net income			
Tampa Electric	$ 250.8	$ 241.0	$ 224.5
PGS	34.9	35.3	35.8
	$ 285.7	$ 276.3	$ 260.3

TAMPA ELECTRIC

Electric Operations Results

Net income in 2016 was $250.8 million, compared with $241.0 million in 2015, driven by higher base revenues from 1.6% higher average number of customers partially offset by higher operations and maintenance and depreciation expense. Full-year net income in 2016 included $24.1 million of AFUDC-equity, $6.5 million of federal R&D tax credits and other tax deductions including Section 199 deduction, compared with $17.2 million of AFUDC-equity and no federal R&D tax credits in the 2015 period. See the **Operating Revenues and Operating Expenses** section for additional information.

Net income in 2015 was $241.0 million, compared with $224.5 million in 2014, driven by higher revenues resulting from a 1.8% increase in average number of customers and higher energy sales resulting from customer growth, warmer than normal spring and early winter weather and a stronger economy. Higher operations and maintenance, depreciation and interest expenses partially offset the higher revenues. Full-year net income in 2015 included $17.2 million of AFUDC-equity, compared with $10.5 million in 2014. See the **Operating Revenues and Operating Expenses** sections below for additional information.

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

Summary of Operating Results

(millions, except customers and total degree days)	*2016*	*% Change*	*2015*	*% Change*	*2014*
Revenues	**$ 1,964.5**	(2.7)	$ 2,018.3	(0.1)	$ 2,021.0
O&M expense	**424.0**	0.8	420.6	0.5	418.4
Depreciation and amortization expense	**268.4**	4.6	256.7	3.3	248.6
Taxes, other than income	**156.6**	0.1	156.4	1.1	154.7
Non-fuel operating expenses	**849.0**	1.8	833.7	1.4	821.7
Fuel expense	**568.3**	(11.8)	644.4	(6.9)	692.5
Purchased power expense	**104.1**	31.9	78.9	10.5	71.4
Total fuel & purchased power expense	**672.4**	(7.0)	723.3	(5.3)	763.9
Total operating expenses	**1,521.4**	(2.3)	1,557.0	(1.8)	1,585.6
Operating income	**$ 443.1**	(3.9)	$ 461.3	5.9	$ 435.4
AFUDC-equity	**$ 24.1**	40.1	$ 17.2	63.8	$ 10.5
Provision for income taxes	**$ 129.8**	(9.6)	$ 143.6	7.8	$ 133.2
Net income	**$ 250.8**	4.1	$ 241.0	7.3	$ 224.5
Megawatt-Hour Sales (thousands)					
Residential	**9,188**	1.6	9,045	4.5	8,656
Commercial	**6,310**	0.1	6,301	2.6	6,142
Industrial	**1,928**	3.1	1,870	(1.6)	1,901
Other	**1,808**	0.9	1,791	(2.0)	1,827
Total retail	**19,234**	1.2	19,007	2.6	18,526
Sales for resale	**206**	79.1	115	(55.5)	259
Total energy sold	**19,440**	1.7	19,122	1.8	18,785
Retail customers—(thousands)					
At December 31	**736.0**	1.7	723.6	1.8	710.9
Retail net energy for load	**20,165**	0.3	20,103	4.1	19,315
Total degree days	**4,462**	(5.6)	4,729	17.1	4,038

Operating Revenues

In 2016, retail MWh sales, measured on a billing cycle basis as shown in the table above grew 1.2% from 2015 levels. Sales in 2016 reflected warmer than normal third quarter weather, strong customer growth and a stronger local economy. Pretax base revenue was $11.7 million higher than in 2015, including approximately $5 million of higher pretax base revenue due to the base rate increase effective November 1, 2015, as a result of the 2013 rate case settlement. Pretax base revenues exclude revenues that recover costs from customers through clauses and riders. Total net energy for load, which is a calendar measurement of retail energy sales rather than a billing cycle measurement, increased 0.3% in 2016 compared to 2015. Energy sales were higher compared to 2015 due to customer growth. In 2016, total degree days in Tampa Electric's service area were 7% above normal and 6% below 2015 levels.

In 2016, retail energy sales to residential and commercial customers increased primarily due to customer growth. Sales to non-phosphate industrial customers increased due to the strength of the Tampa area economy. Sales to lower-margin industrial-phosphate customers increased as a result of increased mining operations plus the decrease of self-generation.

In 2015, retail MWh sales, measured on a billing cycle basis as shown in the table above grew 2.6% from 2014 levels. Sales in 2015 reflected warmer than normal second and fourth quarter weather, strong customer growth and a stronger local economy. Pretax base revenue was more than $37 million higher than in 2014, including approximately $8 million of higher pretax base revenue due to the base rate increases effective November 1, 2014 and November 1, 2015, as a result of the 2013 rate case settlement. Total net energy for load, which is a calendar measurement of retail energy sales rather than a billing cycle measurement, was 4.1% higher than in 2014. Higher energy sales were driven by more favorable weather in 2015 than in 2014. In 2015, total degree days in Tampa Electric's service area were 12% above normal and 17% above 2014.

Tampa Electric is not a major participant in the wholesale market because it uses its own generation to serve its retail customers rather than selling into the wholesale market. In 2016, gross revenues from wholesale sales, which includes fuel that is a pass-through cost, was less than 1% of total revenues. Sales for resale increased 79.1% in 2016 due to warmer than normal temperatures in the third quarter which drove additional power sales. Sales for resale decreased 55.5% in 2015 due to the availability of low-cost natural gas fired generation in the state mitigating the need for Tampa Electric's generating resources.

Customer and Energy Sales Growth Outlook

The Florida economy has continued to grow, as evidenced by success in local economic development activities, by job growth, and by improvements in the new housing construction market, which has been a major driver of growth in the Florida economy for many years (see the **Risk Factors** section). In 2016, there was an almost 20% increase in new single family home building permits in Tampa Electric's service area and an increase of more than 60% in multifamily building permits compared to 2015. In general, economists are forecasting a continued improvement in the state and local economies in 2017 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. In 2017, weather-normalized retail energy sales to residential, commercial and non-phosphate industrial customers are expected to grow at a rate of approximately 1.5%.

Longer-term, assuming continued economic growth and business expansion, Tampa Electric expects annual customer growth to average 1.6% and weather-normalized average retail energy sales growth at a rate of approximately 1.3% to 1.5% in the near term, and about 1.5% over the longer-term. This energy sales growth projection reflects increased lighting and appliance efficiency, 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 2016. The Tampa metropolitan area added over 38,000 new jobs in 2016. Job growth was concentrated in business and other services. The total nonfarm employment in the Tampa metropolitan area increased 3.1% in 2016 following a 3.4% increase in 2015. The local Tampa area unemployment rate decreased to 4.6% in 2016 compared with 5.1% in 2015 and 6.0% in 2014. The Tampa area 2016 unemployment rate was below the state of Florida's unemployment rate of 4.8% and the national unemployment rate of 4.9%.

Tampa Electric anticipates earnings within the allowed ROE range in 2017 and expects earnings and rate base growth as a result of continued customer growth and a focus on cost control.

Operating Expenses

Total pretax operating expense was 2.3% lower in 2016 compared to 2015, driven primarily by lower fuel expense partially offset by higher O&M expense. O&M expenses, excluding all FPSC-approved cost-recovery clauses, increased $9.2 million in 2016, reflecting higher costs to safely and reliably serve customers.

Total pretax operating expense was 1.8% lower in 2015 compared to 2014, driven primarily by lower fuel expense partially offset by higher O&M expense. O&M expenses, excluding all FPSC-approved cost-recovery clauses, increased $5.4 million in 2015, reflecting higher costs to safely and reliably serve customers partially offset by lower employee-related expenses.

In 2016 and 2015, depreciation and amortization expense increased $7.2 million and $5.0 million, respectively, reflecting additions to facilities to serve customers. In 2017, depreciation expense is expected to increase due to normal plant additions and the addition of Polk 2-5 combined cycle coming into service in January 2017.

Excluding all FPSC-approved cost-recovery clause-related expense, O&M expense in 2017 is expected to be lower than in 2016 due to fewer planned outages in 2017.

Fuel Prices and Fuel Cost Recovery

In November 2016, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2017. The rates include the expected cost for natural gas and coal in 2017, and the net over-recovery of fuel, purchased power and capacity clause expense.

Total fuel cost decreased in 2016, due to increased lower-cost natural gas-fired generation and lower costs for natural gas. Purchased-power expense increased in 2016 due to higher volumes of energy purchased from others. Delivered natural gas prices decreased 12.7% in 2016 due to abundant supplies of natural gas from on-shore domestic natural gas produced from shale formations, and storage inventories above historic averages. Delivered coal costs increased 4.9% in 2016. The average coal and natural gas costs were $3.61/MMBTU and $3.79/MMBTU, respectively, in 2016, compared with $3.44/MMBTU and $4.34/MMBTU, respectively, in 2015.

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 be in the $3.50 to $4.00/MMBTU range in 2017, and between $2.75 and $4.00 in 2018, both of which are higher than the 2016 NYMEX natural gas price of $2.46. Current natural gas prices reflect reduced natural gas drilling, offset by high storage levels due to a mild start to the winter heating season and low-cost production from shale basins in the U.S. Compared to 2016, delivered coal prices are expected to decrease slightly in 2017. Tampa Electric continues to burn primarily Illinois Basin coal with small amounts of Northern Appalachian coal, petroleum coke, and South American coal. The price for coal commodity in 2017 is expected to be relatively similar to 2016, but lower transportation costs will provide a slightly lower delivered cost.

Solar Initiatives

In 2015, Tampa Electric announced plans for a 23-MW utility-scale solar photo voltaic project to be installed at Tampa Electric's Big Bend Station. This is the largest solar project in the Tampa Bay area, consisting of more than 200,000 solar panels on 100 acres of land owned by Tampa Electric. Upon completion, which is expected to occur in February 2017, it will have the capacity to power more than 3,500 homes. In 2015, Tampa Electric completed the construction of a 2-MW solar photo voltaic energy installation at Tampa International Airport, which is Tampa Electric's first large-scale solar facility. In 2016, Tampa Electric completed the construction of a 1.8-MW solar photo voltaic energy installation at LEGOLAND Florida. Tampa Electric owns the solar photo voltaic arrays, and the electricity they produce goes to the grid to benefit all Tampa Electric customers, including the airport and LEGOLAND. Tampa Electric anticipates developing additional similarly sized small-scale solar photo voltaic installations and is seeking opportunities for additional utility-scale installations.

Tampa Electric has installed 2,135 KW of solar panels to generate electricity at eight 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 LEGOLAND Florida.

In Florida, a constitutional amendment was proposed that would allow the sale of up to 2 MW of power direct to other customers from rooftop solar panels, potentially bypassing any utility. The Florida Supreme Court ruled that the amendment met constitutional and statutory requirements to appear on the ballot; however, supporters were unable to gather and certify the required number of signatures by the deadline to have it placed on the ballot in 2016. Supporters of the amendment have indicated that they plan to try to have the amendment placed on the ballot in 2018. Legislation was proposed for consideration in the 2016 Florida legislative session that essentially mirrored the intent of the constitutional amendment, but it did not pass. A second Florida constitutional amendment regarding solar power, known as Amendment 1, was on the 2016 ballot but it was not passed by the voters.

Polk Power Station Units 2 – 5 Combined Cycle Conversion

On January 16, 2017, the combined cycle unit at the Polk Power Station was placed in service and available to meet winter demand needs of its customers. The 2016 capital expenditures for the conversion of the Polk CTs to combined cycle and the related transmission system improvements to support the additional generating capacity are included in the **Capital Investments** section below. Under a 2013 settlement agreement with the FPSC, Tampa Electric's base rates increased by $110 million pre-tax effective January 16, 2017, when the Polk 2 – 5 conversion entered commercial service.

PGS

Operating Results

In 2016, PGS reported net income of $34.9 million, compared with $35.3 million in 2015. Results reflect higher residential sales volumes driven by 2.5% higher average number of customers and higher commercial sales volumes driven by a strong economy. Off-system sales increased due to weather related power demand, coal to gas switching by power generators, and pipeline transportation constraints in some areas of the state. Excluding all FPSC-approved cost-recovery clauses, O&M expense was $3.6 million higher in 2016 than in 2015, driven by higher operating and employee benefit costs. Depreciation and amortization expense increased $1.9 million, which includes a $16 million pretax decrease in depreciation offset by a $16 million pretax increase in amortization of the regulatory asset associated with environmental remediation costs per the settlement agreement approved by the FPSC.

In 2015, PGS reported net income of $35.3 million, compared with $35.8 million in 2014. Results reflect a 2.1% higher average number of customers and lower therm sales to residential customers due to mild winter weather. Higher commercial sales volumes were driven by a strong economy and an almost 30% increase in therms sold to CNG vehicle fleets. Sales to power generation customers increased due to higher state-wide electricity demand due to warmer than normal second and fourth quarter weather. Off-system sales increased due to weather related power demand, coal to gas switching by power generators, and pipeline transportation constraints in some areas of the state. Non-fuel O&M expense was $1.9 million higher in 2015 than in 2014, driven by higher operating costs, partially offset by lower employee-related costs, primarily due to the level of short-term incentive accruals for all employees in 2015 compared to 2014. O&M expense in 2014 reflected a first-quarter recovery of $1.6 million of costs incurred in connection with a 2010 outage incident. Depreciation and amortization expense increased slightly due to normal additions to facilities to serve customers.

In 2016 and 2015, total throughput for PGS was approximately 1.9 billion therms and 1.8 billion therms, respectively. The increase is due primarily to off-system sales. In 2016, total throughput increased 7.5% from 2015 levels due to the higher volumes transported for industrial customers and higher off-system sales. In 2016, industrial and power generation customers represented approximately 57% of annual therm volume, commercial customers used approximately 26%, approximately 13% was sold off-system, and the remainder was consumed by residential customers.

Residential customers comprised approximately 33% of total revenues in 2016, down from 35% of total revenues in 2015 due to the mix of higher commercial, industrial, and off -system sales revenue in 2016. New residential construction, which includes natural gas and conversions of existing residences to natural gas, increased in 2016 and 2015 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 increased approximately 30% in 2016 and 2015, respectively, to 25.6 million therms and 19.8 million therms in 2016 and 2015, respectively. Currently, there are 44 CNG fueling stations connected to the PGS system serving over 1,450 vehicles of various sizes. In 2017, the number of vehicles already converted or committed to conversion are expected to consume almost 26 million therms annually, the equivalent consumption of more than 109,000 typical Florida residential customers. Additional stations are expected to be added in 2017, driven by attractive economics, even in the current low-oil price environment, and by lower emissions profile of CNG vehicles. In 2016, PGS placed three company owned CNG filling stations in service, and the cost of these stations will be recovered over time through a special rate approved by the FPSC. CNG conversions 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 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, except customers)	***2016***	*% Change*	*2015*	*% Change*	*2014*
Revenues	**$ 439.3**	7.8	$ 407.5	2.0	$ 399.6
Cost of gas sold	**158.7**	16.9	135.8	(0.9)	137.0
Operating expenses	**211.2**	5.0	201.1	5.6	190.5
Operating income	**$ 69.4**	(1.7)	$ 70.6	(2.1)	$ 72.1
Net income	**$ 34.9**	(1.1)	$ 35.3	(1.4)	$ 35.8
Therms sold – by customer segment					
Residential	**77.6**	3.6	74.9	(7.3)	80.8
Commercial	**488.3**	3.7	470.8	2.2	460.5
Industrial	**321.0**	11.1	289.0	5.4	274.3
Off-system sales	**245.1**	47.3	166.4	98.1	84.0
Power generation	**759.5**	0.2	758.3	17.8	643.5
Total	**1,891.5**	7.5	1,759.4	14.0	1,543.1
Therms sold – by sales type					
System supply	**347.0**	29.1	268.7	38.3	194.2
Transportation	**1,544.5**	3.6	1,490.7	10.5	1,348.9
Total	**1,891.5**	7.5	1,759.4	14.0	1,543.1
Customer (thousands) – at December 31	**374.1**	2.6	364.7	2.1	357.2

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 PGS when a customer shifts to transportation-only sales. PGS markets its unbundled gas delivery services to customers through its "NaturalChoice" program. At year-end 2016, approximately 64% of the 37,640 of PGS's eligible non-residential customers had elected to take service under this program.

PGS Outlook

In 2017, PGS expects customer growth at rates in line with those experienced in 2016, reflecting its expectations that the housing markets in many areas of the state that it serves will continue to grow. Assuming normal weather, therm sales to weather-sensitive customers, especially residential customers, are expected to increase in 2017 at rates that are in line with customer growth. Excluding all FPSC-approved cost-recovery clause-related expenses, O&M expense in 2017 is expected to be slightly higher than in 2016, with higher costs to operate and maintain the system and to reliably serve customers as well as technology related costs. Depreciation and amortization expense is expected to be lower due to the recently approved depreciation rates and associated environmental amortization (see **Note 3** to the **2016 Annual TEC Consolidated Financial Statements**).

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 2017, PGS expects capital spending to increase to support residential and commercial customer growth, system expansion to serve large commercial and industrial customers, liquefied natural gas opportunities, continued interest in conversion of vehicle fleets to CNG and replacement of cast iron, bare steel pipe and other pipe deemed obsolete by the Pipeline Safety and Hazardous Materials Administration.

The current rate of new residential development in Florida has recovered significantly since the economic recession. Complementing the renewed residential construction is the PGS business model for system expansion 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, and the lower emissions levels from using natural gas compared to other fuels, make it attractive for these customers to convert from other fuels even in the current low oil-price environment.

PGS anticipates earnings within the allowed ROE range in 2017 and expects earnings and rate base growth as a result of continued customer growth.

OTHER ITEMS IMPACTING NET INCOME

Other Income, Net

Other income, net was $31.2 million, $19.6 million and $15.3 million in 2016, 2015 and 2014, respectively, and included AFUDC-equity and other items and services such as lightning surge protection equipment. AFUDC-equity at Tampa Electric was $24.1 million, $17.2 million, and $10.5 million in 2016, 2015 and 2014, respectively. The increase in AFUDC-equity is due to the Polk conversion project (see the **Polk Power Station Units 2 – 5 Combined Cycle Conversion** section above). AFUDC is expected to decrease in 2017 primarily due to the Polk conversion project being placed in service in January 2017. In addition, other income, net increased in 2016 compared to 2015 due to a loss on disposition that occurred in 2015.

Interest Expense

In 2016, interest expense, excluding AFUDC-debt, was $117.3 million compared to $117.9 million in 2015 and $111.7 million in 2014. In 2016, interest expense was similar to 2015 due to no new debt issuances at TEC and similar short-term borrowing levels related to its capital spending program. Interest expense in 2015 increased compared to 2014 due to additional borrowings to support its capital spending program.

Interest expense is expected to increase in 2017, reflecting lower AFUDC-debt and higher short-term interest rates and balances.

Income Taxes

The provision for income taxes decreased in 2016, primarily due to tax benefits related to AFUDC-equity and federal R&D tax credits. Income tax expense as a percentage of income before taxes was 34.8% in 2016, 37.5% in 2015 and 37.5% in 2014. We expect our 2017 annual effective tax rate to be approximately 38.6%. The expected increase is due to the tax benefits in 2016 which are not expected in 2017.

Prior to July 1, 2016, TEC was included in a consolidated U.S federal income tax return with TECO Energy and subsidiaries. Effective July 1, 2016 and due to the Merger with Emera, TEC is included in a consolidated U.S. federal income tax return with EUSHI and its subsidiaries. TEC’s income tax expense is based upon a separate return method, modified for the benefits-for-loss allocation in accordance with TECO Energy’s and EUSHI’s respective tax sharing agreements. The cash payments (refunds) for federal income taxes and state income taxes made under those tax sharing agreements totaled $(3.0) million, $63.7 million and $52.6 million in 2016, 2015 and 2014, respectively. See **Cash from Operating Activities** below for further information regarding the cash payments.

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 **2016 Annual TEC Consolidated Financial Statements**.

LIQUIDITY, CAPITAL RESOURCES

Balances as of December 31, 2016

(millions)		
Credit facilities	$	475.0
Drawn amounts/LCs		170.5
Available credit facilities		304.5
Cash and short-term investments		9.5
Total liquidity	$	314.0

Cash from Operating Activities

Cash flows from operating activities in 2016 increased compared to 2015. The change is primarily due to higher accounts payable as a result of higher fuel accruals and higher costs to safely and reliably operate the system; lower fuel inventory balances due to higher fuel consumption; lower customer accounts receivable balances due to lower revenue in the fourth quarter of 2016; and a higher deferred recovery clause balance due to over-recovery in 2016 as fuel prices were lower than projected. In addition, TEC received $61 million in tax refunds from TECO Energy in 2016, and TEC's tax payments decreased due to the impact of the extension of bonus depreciation in December 2015. Cash from operations in 2016 and 2015 also reflect pension contributions of $31 million and $44 million, respectively.

Cash from Investing Activities

Our investing activities in 2016 resulted in a net use of cash of $718 million, which primarily reflects capital expenditures. We expect capital spending in 2017 to be approximately $550 million. The expected decrease compared to 2016 is due to the completion in January 2017 of the Polk Power Station Units 2 – 5 combined cycle conversion and the Customer Relationship Management and Billing System implementation. See the **Capital Investments** section for additional information.

Cash from Financing Activities

Our financing activities in 2016 resulted in net cash outflows of $113 million. TEC repaid $83 million of maturing long-term debt and paid $288 million of dividends to TECO Energy, which was partially offset by $150 million of equity contributions from TECO Energy and a net increase in borrowings from credit facilities of $109 million.

Cash and Liquidity Outlook

Our tariff-based gross margins are our principal source of cash from operating activities. A diversified retail customer mix, primarily consisting of rate-regulated residential, commercial, and industrial customers, provides us with a reasonably predictable source of cash. In addition to using cash generated from operating activities, we use available cash and credit facility borrowings to support normal operations and temporary capital requirements. We may reduce our short-term borrowings with cash from operations, long-term borrowings, or capital contributions from TECO Energy. We expect to make significant capital expenditures in 2017 as we invest in our electric and natural gas utility infrastructure to support overall system reliability, environmental compliance, and other improvements. We intend to fund those capital expenditures with available cash on hand, cash generated from operating activities, and equity contributions and debt issuances so that we maintain our capital structures consistent with our existing regulatory arrangements.

The use of cash from operating activities and short-term borrowings to fund capital expenditures and other long-term investments may periodically result in a working capital deficit, defined as current liabilities exceeding current assets, as was the case at December 31, 2016. The working capital deficit as of December 31, 2016 was primarily the result of increases in short-term liabilities due to FPSC clauses and riders. Any assets or liabilities related to FPSC clauses and riders are recovered or refunded through cost-recovery mechanisms approved by the FPSC on a dollar-for-dollar basis in the next year. At December 31, 2016, our liquidity was $314 million.

TEC has multiyear credit facilities that cumulatively provide $475 million of credit through 2018. See **Note 6** to the **2016 Annual TEC Consolidated Financial Statements** for additional information regarding the credit facilities. TEC believes that its liquidity is adequate given its expected operating cash flows, capital expenditures, and related financing plans. However, there can be no assurance that significant changes in economic conditions, disruptions in the capital and credit markets, or other unforeseen events will not materially affect its ability to execute its expected operating, capital, or financing plans.

We expect cash from operations in 2017 to be lower than in 2016, due in large part to prior year fuel clause over-recoveries included in the 2017 fuel rate. We plan to use cash in 2017 to fund capital spending estimated at $550 million, and to pay dividends to our shareholder, TECO Energy. Dividends are declared and paid at the discretion of TEC's Board of Directors.

We expect to utilize cash from operations and equity contributions from TECO Energy to support our capital spending programs, supplemented with incremental long-term debt and utilization of our credit facilities to maintain strong utility capital structures. Our credit facilities contain certain financial covenants (see **Covenants in Financing Agreements** section). We estimate that we could fully utilize the total available capacity under our facilities in 2017 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. 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).

TEC currently holds investment grade credit ratings from Moody's, S&P and Fitch (see **Credit Ratings** section). In the event TEC'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 December 31, 2016, we would not have been required to post additional collateral or settle existing positions with counterparties. In addition, credit provisions in long-term gas transportation agreements would give the transportation providers the right to demand collateral, which we estimate to be approximately $70 million. None of our credit facilities or financing agreements have ratings downgrade covenants that would require immediate repayment or collateralization.

Short-Term Borrowings

At December 31, 2016 and 2015, the following credit facilities and related borrowings existed.

	December 31, 2016			*December 31, 2015*		
(millions)	Credit Facilities	Borrowings Outstanding(1)	Letters of Credit Outstanding	Credit Facilities	Borrowings Outstanding(1)	Letters of Credit Outstanding
5-year facility(2)	$ 325.0	$ 40.0	$ 0.5	$ 325.0	$ 0.0	$ 0.5
1-year / 3-year accounts receivable facility(3)	150.0	130.0	0.0	150.0	61.0	0.0
Total	$ 475.0	$ 170.0	$ 0.5	$ 475.0	$ 61.0	$ 0.5

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures December 17, 2018.
(3) This 3-year facility matures on March 23, 2018.

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 December 31, 2016 and 2015 was 1.49% and 0.89%, respectively. For a complete description of the credit facilities see **Note 6** to the **2016 Annual TEC Consolidated Financial Statements.**

(millions)	Maximum drawn amount	Minimum drawn amount	Average drawn amount	Average interest rate
2016 credit facility utilization	$ 170.0	$ 0.0	$ 61.8	1.17%

Significant Financial Covenants

In order to utilize its 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 December 31, 2016, TEC was in compliance with all applicable financial covenants. The table that follows lists the significant financial covenants and the performance relative to them at December 31, 2016. Reference is made to the specific agreements and instruments for more details.

(millions, unless otherwise indicated)

Instrument	**Financial Covenant (1)**	**Requirement/Restriction**	**Calculation at December 31, 2016**
Credit facility (2)	Debt/capital	Cannot exceed 65%	45.8%
Accounts receivable credit facility (2)	Debt/capital	Cannot exceed 65%	45.8%

(1) As defined in each applicable instrument.
(2) See **Note 6** to the **2016 Annual TEC Consolidated Financial Statements** for a description of the credit facilities.

Credit Ratings

	S&P	Moody's	Fitch
Credit ratings of senior unsecured debt	BBB+	A3	A-

On July 6, 2016, following the Merger with Emera, Moody's downgraded the issuer rating and senior unsecured ratings of TEC to A3 from A2. This concluded the ratings review commenced by Moody's on June 2, 2016. Moody's described the ratings outlook as "Stable".

On July 1, 2016, following the Merger with Emera, S&P affirmed the senior unsecured debt rating of TEC and maintained the ratings outlook at negative.

On Oct. 9, 2015, Fitch Ratings affirmed the senior unsecured debt rating of TEC. Fitch Ratings described the ratings outlook as "Stable".

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 TEC'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 13** to the **2016 Annual TEC Consolidated Financial Statements)**.

Summary of Contractual Obligations

The following table lists the obligations of TEC for cash payments to repay debt, interest payments, lease payments and unconditional commitments related to capital expenditures.

Contractual Cash Obligations at December 31, 2016

	Payments Due by Period						
(millions)	***Total***	***2017***	***2018***	***2019***	***2020***	***2021***	***After 2021***
Long-term debt[1]	$ 2,182.6	$ 0.0	$ 304.2	$ 0.0	$ 0.0	$ 278.4	$ 1,600.0
Interest payment obligations	1,740.3	107.4	98.3	89.1	89.1	81.6	1,274.8
Operating leases/purchased power	75.5	17.7	13.6	2.1	2.1	2.2	37.8
Long-term service agreements/capital projects[2]	129.8	68.8	11.1	11.8	6.8	6.9	24.4
Clause recoverable commitments[3]	2,267.5	398.5	231.0	186.2	162.9	132.3	1,156.6
Pension plan[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total contractual obligations	$ 6,395.7	$ 592.4	$ 658.2	$ 289.2	$ 260.9	$ 501.4	$ 4,093.6

(1) Includes debt at Tampa Electric and PGS (see **Note 7** to the **2016 Annual TEC Consolidated Financial Statements** for a list of long-term debt and the respective due dates).

(2) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At December 31, 2016, these commitments include Tampa Electric's outstanding commitments for major projects and long-term capitalized maintenance agreements for its CTs.

(3) These payment obligations under contractual agreements of Tampa Electric and PGS for fuel, fuel transportation and power purchases are recovered from customers under regulatory clauses approved by the FPSC (see the **Business** section).

(4) Under calculation requirements of the Pension Protection Act, as of the January 1, 2017 measurement date, our pension plan was 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 investment portfolio performance, and other factors (see **Liquidity, Capital Resources** section and **Note 5** to the **2016 Annual TEC Consolidated Financial Statements**).

Off-Balance Sheet Arrangements and Contingent Obligations

TEC does not have any material off-balance sheet arrangements or contingent obligations not otherwise included in our Consolidated Financial Statements as of December 31, 2016. See **Note 9** to the **2016 Annual TEC Consolidated Financial Statements.**

Capital Investments

(millions)		*Actual 2016*		*Forecasted 2017*
Tampa Electric [(1)]				
Transmission	$	71	$	30
Distribution		163		178
Generation		194		118
New renewable generation		31		10
Facilities, equipment, vehicles and other		114		65
Tampa Electric total		573		401
PGS		133		149
Net cash effect of accruals, retentions and AFUDC		21		0
Total	$	727	$	550

(1) Individual line items exclude AFUDC-debt and equity.

Tampa Electric's 2016 capital expenditures included $134 million for the Polk 2-5 conversion to combined cycle and related transmission system improvements, $30 for solar generation projects, $35 million for the Customer Information System with a Customer Relationship Management and Billing System (CRMB), $53 million for hurricane storm hardening for both the transmission and distribution systems, and $100 million for the maintenance and refurbishment of existing generating facilities. In 2017, Tampa Electric expects capital expenditures related to the Big Bend duel fuel conversion, completion of the CRMB project, utility scale solar projects, and new technology for distribution system modernization and automated metering equipment.

Capital expenditures in 2016 for PGS included approximately $37 million for maintenance of the existing system, $80 million to expand the system and support customer growth, and $16 million for replacement of cast iron and bare steel pipe. PGS expects to spend approximately $100 million in 2017 for projects associated with customer growth, system expansion, and construction of CNG facilities. The remainder of PGS's capital expenditure forecast for 2017 includes amounts related to ongoing renewal, replacement and system safety, including the replacement of cast iron, bare steel and obsolete plastic pipe, which is recovered through a rider clause (see the **Business–PGS-Regulation** section).

The forecasted capital expenditures shown above are based on our current estimates and assumptions. 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

At December 31, 2016, TEC's year-end capital structure was 46% debt and 54% common equity. At December 31, 2015, TEC's year-end capital structure was 47% debt and 53% common equity.

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 **2016 Annual TEC 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 December 31, 2016, we had a net deferred income tax liability of $1,407 million, attributable primarily to property-related items.

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 3** to the **2016 Annual TEC Consolidated Financial Statements**.

Employee Postretirement Benefits

TEC is a participant in the retirement plans of TECO Energy. TECO Energy sponsors a defined benefit pension plan (pension plan) and a fully-funded non-qualified, non-contributory supplemental executive retirement benefit plan available to certain members of senior management. TEC recognizes in its statement of financial position the over-funded or under-funded status of its allocated portion of TECO Energy's postretirement benefit plans. The accounting related to employee postretirement benefits is a critical accounting estimate for TEC for the following reasons: 1) a change in the estimated benefit obligation could have a material impact on reported assets, liabilities and results of operations; and 2) changes in assumptions could change the annual pension funding requirements, which could have a significant impact on TEC's annual cash requirements.

Several statistical and other factors which attempt to anticipate future events are used in calculating the expenses and liabilities related to these plans. Key factors include assumptions about the expected rates of return on plan assets, discount rates and mortality rates. TECO Energy management (Management) determines these factors within certain guidelines and with the help of external consultants. Management considers 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 that was occurring in 2014, Management reduced the expected return on assets from 7.25% to 7.00% during 2014. No such reduction was deemed necessary in 2015 or 2016. Management 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 2016 were 9.2%.

As a result of the Merger, TECO Energy remeasured its employee postretirement benefit plans on the Merger effective date, July 1, 2016. As part of the remeasurement and to align discount rate methodologies with Emera, TECO Energy used an above-mean yield curve to determine its discount rate. The above-mean yield curve technique matches the yields from high-quality (AA-rated, non-callable) corporate bonds to the company's projected cash flows for the plans to develop a present value that is converted to a discount rate assumption, which is subject to change each year.

TECO Energy previously used a bond model matching technique to determine its discount rate. The discount rate assumption used to determine the 2016 benefit expense through June 30, 2016, the 2015 and 2014 benefit expenses and December 31, 2015 benefit obligation was based on a cash-flow matching technique developed by our 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.

The change in discount rate resulting from the different methodology used to select a discount rate did not have a material impact on TEC's financial statements and provides consistency with Emera's method for selecting a discount rate. For the July 1, 2016 measurement, TECO Energy used a discount rate of 3.72% for pension benefits under its qualified pension plan and 3.85% for its other postretirement benefits plans.

Holding all other assumptions constant, a 1% decrease in the assumed rate of return on pension plan assets or the discount rate assumption would have had in 2016 and is anticipated to have in 2017 the following impact on TEC's after-tax pension cost:

Year	1% Decrease in Assumed Expected Return on Assets	1% Decrease in Assumed Discount Rate
2016	$3.2 million increase	$2.5 million increase
2017	$3.4 million increase	$1.4 million increase

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 were 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.

TECO Energy reviewed its 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.

TECO Energy has determined the SOA mortality tables are not the most appropriate mortality tables to be used in valuing its postretirement benefit plans. Beginning with the 2014 year-end measurement, TECO Energy has utilized a table that is based on the SOA RP-2014 mortality but adjusts it to remove the post-2007 improvement projections for its base scale. For the projection scale, TECO Energy used 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. TECO Energy believes these tables are more appropriate and reflective of its population.

In 2015 and 2016, the SOA updated the projection scale. These updates reflected lesser mortality improvement than was seen in the original 2014 projection scale and were more in line with the projections anticipated by TECO Energy's 2014 projection scale.

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.

TECO Energy'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. TEC's contribution is first set equal to its service cost. If a contribution in excess of service cost for the year is made, TEC's portion is based on TEC's proportion of the TECO Energy unfunded liability.

TECO Energy currently provides certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 who meet certain service requirements. TECO Energy implemented an EGWP for its post-65 retiree prescription drug plan effective January 1, 2013. The EGWP was a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduced 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 were greater than subsidy payments previously received under Medicare Part D for the post-65 retiree prescription drug plan. Effective January 1, 2015, TECO Energy changed its post-65 retiree coverage for medical benefits to a Medicare Advantage plan insured by Aetna in order to take advantage of the government subsidies available for the plan.

The Health Care Reform Acts contain other provisions that may impact TECO Energy's 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. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially impact its postretirement benefit obligation. TECO Energy will continue to monitor and assess the potential impact of the Health Care Reform Acts 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. TECO Energy determines the discount rate for the OPEB's projected benefit cash flows. In estimating the health care cost trend rate, TECO Energy considers its actual health care cost experience, future benefit structures, industry trends, and advice from our outside actuaries. TECO Energy assumes 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.

TECO Energy's Florida-based plan's assumed health care cost trend rate for medical costs was 7.05% during 2016 and graded down to 6.83% for the December 31, 2016 measurement. This rate, over time, will decrease to 4.50% in 2038 and thereafter. A 1% increase in the health care trend rates would have produced a $0.1 million after-tax increase in the aggregate service and interest cost for 2016, and an estimated $0.1 million increase in 2017.

The actuarial assumptions used in determining TECO Energy'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 **2016 Annual TEC Consolidated Financial Statements**.

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. 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 U.S. 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 costs and required investment associated with future changes in environmental regulations would create regulatory assets. Current regulation in Florida 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** section).

We regularly 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.

TEC's most significant regulatory liability relates to non-ARO costs of removal. The non-ARO costs of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment upon retirement. TEC accrues for removal costs over the life of the related assets based on depreciation studies approved by the FPSC. The costs are estimated based on historical experience and future expectations, including expected timing and estimated future cash outlays.

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 in **Item 1. Business** and **Note 3** to the **2016 Annual TEC Consolidated Financial Statements**).

RECENTLY ISSUED ACCOUNTING STANDARDS

Change in Accounting Policy

The new U.S. GAAP accounting policies that are applicable to and were adopted by TEC are described as follows:

Interest – Imputation of Interest

In April 2015, the FASB issued Accounting Standard Update (ASU) 2015-03, *Interest – Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected. TEC adopted this standard in the first quarter of 2016, and December 31, 2015 balances have been retrospectively restated. This change resulted in $18.1 million of debt issuance costs as of December 31, 2015, previously presented as "Deferred charges and other assets", being reclassified as a deduction from the carrying amount of the related "Long-term debt, less amount due within one year" line item on its Consolidated Balance Sheet. In accordance with ASU 2015-15 *Interest: Imputation of Interest*, TEC continues to present debt issuance costs related to its letter of credit arrangements and related instruments in "Prepayments and other current assets" on its Consolidated Balance Sheets.

Derivatives and Hedging - Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships

In March 2016, the FASB issued ASU 2016-05, *Derivatives and Hedging Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships.* The standard clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the dedesignation of a hedging relationship provided that all other hedge accounting criteria continue to be met. TEC early adopted in 2016 as permitted.

Future Accounting Pronouncements

TEC considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB but have not yet been adopted by TEC. Any ASUs not included below were assessed and determined to be either not applicable to TEC or to have minimal impact on the consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new principle-based revenue recognition framework, which has been codified as ASC Topic 606. The FASB issued amendments to ASC Topic 606 during 2016 to clarify certain implementation guidance and to reflect narrow scope improvements and practical expedients. 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 to. The guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and will allow for either full retrospective adoption or modified retrospective adoption. TEC will adopt this guidance effective January 1, 2018. TEC has implemented a project plan and is in the process of evaluating the impact of adoption of this standard on its consolidated financial statements and disclosures. This includes evaluating the available adoption methods, accounting for contributions in aid of construction and contract acquisition costs, and disclosure requirements. TEC is also monitoring the assessment of ASC Topic 606 by the AICPA Power and Utilities Revenue Recognition Task Force. While TEC does not currently expect the impact to be significant, the ultimate impact of the adoption of ASC Topic 606, and the method of adoption, has not yet been finalized.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities.* The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. TEC does not have equity investments or available-for-sale debt securities and it does not record financial liabilities under the fair value option. However, it is currently evaluating the impact of the adoption of this guidance on its financial statement disclosures. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

Leases

In February 2016, the FASB issued ASU 2016-02, *Leases.* The standard, codified as ASC Topic 842, increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with terms of more than 12 months. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and is required to be applied using a modified retrospective approach. TEC is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted for annual reporting periods, including interim periods after December 15, 2018, and will be applied using a modified retrospective approach. TEC is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows

In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows*. The standard provides guidance regarding the classification of certain cash receipts and cash payments on the statement of cash flows, where specific guidance is provided for issues not previously addressed. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. TEC is currently evaluating the impact of adoption of this standard on its consolidated statement of cash flows.

Restricted Cash on the Statement of Cash Flows

In November 2016, the FASB issued ASU 2016-18, *Restricted Cash on the Statement of Cash Flows*. The standard will require TEC to show the changes in total cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. Transfers between cash and cash equivalents and restricted cash and restricted cash equivalents will no longer be presented in the statement of cash flows. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. To date, TEC does not have any restricted cash or restricted cash equivalents.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, *Clarifying the Definition of a Business*. The standard provides guidance to assist entities with evaluating when a set of transferred assets and activities is a business. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied prospectively.

ENVIRONMENTAL COMPLIANCE

Environmental Matters

TEC has significant environmental considerations. Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act. Its operations are also impacted by provisions in the Clean Water Act and federal and state legislative initiatives on environmental matters. 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.

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 November 22, 2013. Termination of the Consent Final Judgment was completed on May 6, 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 NOx 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 **Business-Tampa Electric-Regulation** section). Cost recovery for the repowering of the Bayside Power Station was accomplished in Tampa Electric’s 2008 rate case.

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. On July 7, 2011, EPA released its final CAIR-replacement rule, called Cross-State Air Pollution Rule (CSAPR). An update to CSAPR was finalized on October 26, 2016 and will be implemented in 2017. Based on updated EPA modeling, Florida is no longer subject to CSAPR requirements. However, Florida (including TEC power plants) could be subject to a future version of CSAPR as a result of an expected update triggered by compliance with the more stringent 2015 ozone standard (which is described below) or ongoing litigation relating to current rule applicability.

Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT) Mercury Air Toxics Standards (MATS)

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.

On June 29, 2015, the U.S. Supreme Court remanded the EPA's MATS to the U.S. District of Columbia Circuit Court (the D.C. Circuit Court) for failing to properly consider the cost of compliance. MATS remains in effect until the D.C. Circuit Court acts.

All of Tampa Electric's conventional coal-fired units are already equipped with electrostatic precipitators, 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 MATS standards without considerable impacts, compared to others who have not taken similar early actions. Therefore, Tampa Electric has minimized the impact of this rule and has demonstrated compliance on all applicable units with the most stringent "Low Emitting Electric Generating Unit" classification for MATS with nominal additional capital investment.

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 was placed in service in January 2017 (see the **Tampa Electric** and **Capital Investments** 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 32% and 18%, respectively.

Related to utility sources, the EPA rule that 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 January 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 completed for Tampa Electric's most recent 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. On June 2, 2014, the EPA released a comprehensive proposed rule to limit GHG emissions from existing power plants. The EPA's final rule, the Clean Power Plan, was signed by the Administrator of the EPA on August 3, 2015 and sets emission performance goals that will cut GHG emissions from existing power plants by an average across all states of 32% from their 2012 levels by 2030, with an interim goal for the period from 2022 through 2029.

In January 2016, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by 27 states and numerous trade groups that would have barred the EPA from implementing the carbon regulations for the electricity sector. However, in February 2016, the U.S. Supreme Court issued a stay against enforcement of the Clean Power Plan for the electricity sector pending resolution of the legal challenges before the U.S. Court of Appeals for the District of Columbia Circuit. The timing of the resolution of the legal challenges and the removal of the stay by the U.S. Supreme Court is uncertain, but it is likely to delay further actions by the states until 2018 or later. Prior to the U.S. Supreme Court ruling, Florida had not begun its rulemaking process, and is currently awaiting final resolution of the legal challenges before proceeding with rulemaking. Tampa Electric is evaluating a number of potential compliance scenarios, but there is no Florida initiative to develop a final compliance plan. The outcome of this litigation and the rulemaking process and its impact on TEC's businesses is therefore uncertain at this time; however, it could result in increased operating costs, and/or decreased operations at Tampa Electric's coal-fired plants. Depending on how the state plan is developed and implemented, the Clean Power Plan could cause an increase in costs or rates charged to 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.

Ozone

On September 30, 2015 in response to a court order, the EPA published a final rule revising the ground level ozone standard to 70 parts per billion from the previous level of 75 parts per billion. Compliance with the new standard will be the responsibility of individual states, which will provide flexibility in meeting the standards depending on the severity of each states' ozone levels. States will be required to be in compliance between 2020 and 2037. On September 30, 2016, the Florida Department of Environmental Protection submitted its recommendation that the entire State of Florida be designated as "attainment" for the 2015 standard. EPA is expected to promulgate final ozone attainment designations by October 2017. Litigation regarding the stringency of the rule is ongoing. Therefore, it is not possible to estimate the impact of this new standard on the operations of Tampa Electric or to estimate the potential cost of compliance.

Water Supply and Quality

The EPA's final rule under 316(b) of the Clean Water Act became effective in October 2014. This rule was initially proposed by EPA in response to citizens' lawsuits over perceived impacts to aquatic life resulting from operation of cooling water systems in the U.S. from either impingement (on intake screens) or entrainment (through condensers). Tampa Electric uses water from Tampa Bay as cooling water for its Bayside and Big Bend facilities. 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. Neither station has historically demonstrated any significant adverse environmental impacts. Polk Power Station is not covered by this rule since it does not operate an intake on Waters of the U.S. Tampa Electric has two ongoing projects (one for Bayside and one for Big Bend) to negotiate scheduling with the regulating authority and to complete the biological, technical, and financial study elements necessary to comply with the rule. These study elements will ultimately be used by the regulating authority to determine the necessity of cooling water system retrofits for Big Bend and Bayside Power Stations. The full impact of the new regulations on Tampa Electric will depend on the outcome of subsequent legal proceedings challenging the rule, the results of the study elements performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies.

EPA determined that numeric water quality standards are required in Florida to implement the Clean Water Act. On January 26, 2010, EPA published proposed "Water Quality Standards for the State of Florida's Lakes and Flowing Waters." There was a long, litigious path in which EPA and FDEP both proposed criteria. Ultimately, the courts upheld the ruling that the Florida regulations meet the requirements of the Clean Water Act. Both Big Bend and Bayside Power Stations already have allocations allotted by the Nitrogen Management Consortium of the Tampa Bay Estuary Program for total nitrogen, which is the limiting nutrient for Tampa Bay. Other criteria related to streams 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 EPA rule was published in the U.S. Federal Register November 3, 2015 and became effective January 4, 2016. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals (CCRs), gasification processes, and flue gas mercury controls. For FGD wastewater, the rule imposed limits for arsenic, mercury, selenium, and nitrate/nitrite which will require the addition of biological treatment at Big Bend Station. Both fly ash and bottom ash transport water have been designated as zero discharge wastewaters, with the exception of use as make-up water in FGD scrubber. Transport water used as make-up will be subject to FGD wastewater limits at the point of discharge. New limits for gasification processes will likely require additional treatment at Polk Power Station. Cost estimates are being developed based on an evaluation of treatment technologies required to meet the pollutant limits. The new guidelines are expected to be incorporated into NPDES permit renewals to achieve compliance as soon as possible after November 1, 2018, but no later than December 31, 2023.

EPA Waters of the US

In June 2015, the U.S. Army Corps of Engineers (Corps) and the EPA issued a rule defining "Waters of the United States" (WOTUS) for purposes of federal Clean Water Act (CWA) jurisdiction. The final rule took effect on August 28, 2015. The rule has the effect of defining the scope of agency jurisdiction under the CWA very broadly. In August 2015, a federal judge in North Dakota issued an injunction against the implementation of the rule in certain states. In October 2015, the Sixth Circuit Court of Appeals issued a nationwide stay of WOTUS, effectively ending the implementation of the rule in the 37 states that were not subject to the prior injunction. This stay is temporary, pending the outcome of litigation.

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 December 31, 2016, TEC has estimated its ultimate financial liability to be $31.6 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 are expected to be paid over many years.

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. See **Note 3** to the **2016 Annual TEC Consolidated Financial Statements** for information regarding an agreement approved by the FPSC to accelerate the amortization of the regulated asset associated with this reserve.

Coal Combustion Residuals Recycling and Disposal

Tampa Electric produces ash and other by-products, collectively known as CCRs, at its Big Bend and Polk power stations. 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, an annual average of 95% of all CCRs produced at these facilities is marketed to customers for beneficial use in commercial and industrial products. The remaining 5% are either disposed of onsite or shipped offsite to nearby industrial waste landfills in Central Florida.

EPA's final CCR rule became effective on October 19, 2015, and regulates CCRs as non-hazardous solid waste. The rule explicitly allows for encapsulated beneficial uses of CCRs in commercial and industrial products. However, non-encapsulated uses in agricultural and construction applications are allowable only if they meet new environmental criteria. The rule contains design and operating standards for CCR management units. Tampa Electric has determined that capital expenditures will be required to achieve compliance with this rule beginning in 2017. On February 2, 2016, the FPSC approved Tampa Electric's proposed CCR compliance program for cost recovery through the ECRC. However, additional petitions will be submitted for recovery of future capital project expenses based on engineering studies currently being performed. On December 10, 2016, Congress passed the "Water Infrastructure Improvements for the Nation Act" (WIINA), which contains language modifying the implementation plan for the federal CCR Rule. The language amends the Rule so that it will now be administered primarily by the states through state-operated permit programs. The state programs will be approved and overseen by EPA. This change should effectively eliminate the threat of litigation by private citizens as an enforcement mechanism and will instead place compliance and enforcement authority in the hands of the agencies. See **Note 16** to the **2016 Annual TEC Consolidated Financial Statements** for information regarding the estimated ARO impact.

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, a potential amendment to the Florida constitution that supporters are seeking to have placed on the ballot in 2018 would encourage the installation of solar arrays to generate electricity by retail customers and third parties, and allow limited sales of electricity by non-utility generators.

Additionally, the EPA's 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 the **Carbon Reductions and GHG** discussion above, and **Item 1A - Risk Factors)**. Depending on how the rule is 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 efforts to encourage energy efficiency. In 2016, Tampa Electric continued to offer its customers a comprehensive array of residential and commercial programs that enabled it to meet its required Demand Side Management (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, TEC's conservation programs have contributed to reducing the summer peak demand by 685 MW and the winter peak demand by 1,184 MW.

In November 2014, the FPSC established new DSM goals for the 10-year period from 2015 to 2024 for all Florida investor-owned electric utilities. In 2016, Tampa Electric continued with the new 2015-2024 DSM plan that was fully implemented in November 2015. This DSM plan supports the approved FPSC goals which are reasonable, beneficial and cost-effective to all customers as required by the Florida Energy Efficiency & Conservation Act. For Tampa Electric, the summer and winter demand goals are 56.3 and 78.3 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. Tampa Electric met all the annual and incremental DSM goals for 2016 and in May, completed the phased final closure of the "Prime Time" program which was its direct load control Residential Load Management Program. 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 the customer's gas bill.

REGULATION

See the **Business** section (**Tampa Electric – Electric Operations** and **Peoples Gas System – Gas Operations** sections) and **Note 3** to the **2016 Annual TEC Consolidated Financial Statements** for a description of the utilities' base rates, cost-recovery clauses and competition.

PGS Compliance Activities

In 2015, FPSC staff presented PGS with a summary of alleged safety rule violations, many of which were identified during PGS's implementation of an action plan it instituted as a result of audit findings cited by FPSC audit staff in 2013. Through ongoing discussions with the audit staff, PGS was made aware of concerns regarding falsification of documentation in one division. PGS determined that leak-inspection reports in 2014 were falsified. PGS took immediate actions to correct the concerns identified in the findings, including reinspecting all pipes due for inspection in that division in 2014 and repaired deficiencies as appropriate.

The FPSC audit staff published a follow-up audit report that acknowledged the progress that had been made and found that further improvements were needed. As a result of this report, the OPC filed a petition with the FPSC pointing to the violations of rules for safety inspections seeking fines or possible refunds to customers by PGS. On February 25, 2016, the FPSC staff issued a notice informing PGS that the staff would be making a recommendation to the FPSC to initiate a show cause proceeding against PGS for the alleged violations, with total potential penalties of up to \$3.9 million. On April 18, 2016, PGS reached a settlement regarding this matter with the OPC and FPSC staff and agreed to pay a \$1 million civil penalty and customer refunds of \$2 million. The FPSC approved the settlement agreement on May 5, 2016.

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

Risk Management Infrastructure

TEC is subject to various types of market risk in the course of daily operations, as discussed below. TEC has 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).

TEC's Risk Management Policy (Policy) governs all energy transacting activity. The Policy is approved by TECO Energy's 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; and
- Interest rate fluctuations on debt.

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 customers.

In November 2016, Tampa Electric and the other major electric IOUs in Florida signed a stipulation agreement approved by the FPSC calling for a one-year moratorium on hedging of natural gas purchases. The stipulation agreement calls for the FPSC to oversee one or more workshops beginning in early 2017 to seek a cost-effective way to insure against rising gas prices.

Fair Value Measurements

The accounting standards for fair value measurement define fair value, establish a framework for measuring fair value under U.S. GAAP, and expand disclosures about financial assets and liabilities carried at fair value. The majority of TEC's financial assets and liabilities are in the form of natural gas or interest rate derivatives classified as cash flow hedges.

Natural gas derivatives were entered into by TEC 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 and PGS 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.

The valuation methods we used to determine fair value are described in **Note 14** to the **2016 Annual TEC 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 Risk Guidelines, which are approved by the RAC, 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 are made available to management on a daily basis. The Credit Risk 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.

Certain of our derivative instruments contain provisions that require our debt to maintain an investment-grade credit rating from any or all of the major credit rating agencies. If our 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. The aggregate fair value of all derivative instruments with credit-risk-related contingent features were in asset positions on December 31, 2016.

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 December 31, 2016 and 2015, a hypothetical 10% increase in TEC'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 TEC. A hypothetical 10% decrease in interest rates would increase the fair market value of our long-term debt by 4.4% at December 31, 2016 and 4.5% at December 31, 2015. See the **Financing Activity** section and **Notes 6 and 7** to the **2016 Annual TEC Consolidated Financial Statements**. These amounts were determined based on the variable rate obligations existing on the indicated dates at TEC. 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

TEC faces 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

Tampa Electric's fuel costs used for generation are affected primarily by the price of natural gas and, to a lesser degree, the cost of coal, oil and petcoke. Tampa Electric's use of natural gas, with its more volatile pricing, for generation of electricity increased to 56% in 2016 from 52% in 2015 (see the **Business** section). PGS has exposure related to the price of purchased gas and pipeline capacity.

Currently, our commodity price risks are largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through FPSC 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, we 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 December 31, 2016 and 2015, a change in commodity prices would not have had a material impact on earnings for Tampa Electric or PGS, 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

The change in fair value of derivatives is largely due to settlements of natural gas swaps and an increase in the average market price component of TEC's outstanding natural gas swaps of approximately 19% from December 31, 2015 to December 31, 2016. For natural gas, TEC maintained similar volumes hedged as of December 31, 2016 as compared to December 31, 2015.

The following tables summarize the changes in and the fair value balances of TEC's derivative assets (liabilities) for the year ended December 31, 2016:

Changes in Fair Value of Derivatives (millions)

Net fair value of derivatives as of December 31, 2015	$	(26.2)
Additions and net changes in unrealized fair value of derivatives		17.1
Changes in valuation techniques and assumptions		0.0
Realized net settlement of derivatives		25.7
Net fair value of derivatives as of December 31, 2016	$	16.6

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

Total derivative net liabilities as of December 31, 2015	$	(26.2)
Change in fair value of net derivatives:		
Recorded as regulatory assets and liabilities or other comprehensive income		17.1
Recorded in earnings		0.0
Realized net settlement of derivatives		25.7
Total derivative net assets as of December 31, 2016	$	16.6

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at December 31, 2016

(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]		15.1		1.5		16.6
Model prices [2]		0.0		0.0		0.0
Total	$	15.1	$	1.5	$	16.6

(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.

TAMPA ELECTRIC COMPANY

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 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 10, 2017

TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets

Assets *(millions)*	*December 31, 2016*	*December 31, 2015*
Property, plant and equipment		
Utility plant in service		
Electric	$ 7,623.7	$ 7,270.3
Gas	1,503.5	1,398.6
Construction work in progress	891.5	771.1
Utility plant in service, at original costs	10,018.7	9,440.0
Accumulated depreciation	(2,826.1)	(2,676.8)
Utility plant in service, net	7,192.6	6,763.2
Other property	10.7	9.7
Total property, plant and equipment, net	7,203.3	6,772.9
Current assets		
Cash and cash equivalents	9.5	9.1
Receivables, less allowance for uncollectibles of $1.2 and $1.5 at December 31, 2016 and 2015, respectively	205.6	227.9
Due from affiliates	6.9	63.6
Inventories, at average cost		
Fuel	77.0	105.6
Materials and supplies	85.7	73.1
Current derivative assets	15.1	0.0
Regulatory assets	28.1	44.3
Prepayments and other current assets	21.4	21.5
Total current assets	449.3	545.1
Deferred debits		
Regulatory assets	392.6	373.8
Other	37.4	16.8
Total deferred debits	430.0	390.6
Total assets	$ 8,082.6	$ 7,708.6

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

TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets—continued

Liabilities and Capital *(millions)*		*December 31, 2016*		*December 31, 2015*
Capitalization				
Common stock	$	2,455.4	$	2,305.4
Accumulated other comprehensive loss		(2.8)		(3.6)
Retained earnings		311.2		313.7
Total capital		2,763.8		2,615.5
Long-term debt, less amount due within one year		2,162.9		2,161.7
Total capital		4,926.7		4,777.2
Current liabilities				
Long-term debt due within one year		0.0		83.3
Notes payable		170.0		61.0
Accounts payable		262.1		205.7
Due to affiliates		25.2		16.9
Customer deposits		146.0		176.3
Regulatory liabilities		154.2		83.2
Derivative liabilities		0.0		24.1
Accrued interest		16.2		16.9
Accrued taxes		12.2		12.2
Other		10.3		10.2
Total current liabilities		796.2		689.8
Deferred credits				
Deferred income taxes		1,406.6		1,308.8
Investment tax credits		11.4		10.5
Regulatory liabilities		590.6		603.5
Deferred credits and other liabilities		351.1		318.8
Total deferred credits		2,359.7		2,241.6
Commitments and Contingencies (see Note 9)				
Total liabilities and capital	$	8,082.6	$	7,708.6

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 December 31,*	*2016*	*2015*	*2014*
Revenues			
Electric	$ 1,963.6	$ 2,017.7	$ 2,020.5
Gas	432.2	401.5	398.5
Total revenues	2,395.8	2,419.2	2,419.0
Expenses			
Operations & maintenance			
Fuel	561.4	638.6	692.3
Purchased power	104.1	78.9	71.4
Cost of natural gas sold	158.5	135.5	137.0
Other	537.9	528.9	518.4
Depreciation and amortization	328.3	313.5	302.6
Taxes, other than income	193.1	192.0	189.8
Total expenses	1,883.3	1,887.4	1,911.5
Income from operations	512.5	531.8	507.5
Other income			
Allowance for other funds used during construction	24.1	17.2	10.5
Other income, net	7.1	2.4	4.8
Total other income	31.2	19.6	15.3
Interest charges			
Interest expense	117.3	117.9	111.7
Allowance for borrowed funds used during construction	(11.5)	(8.3)	(5.1)
Total interest charges	105.8	109.6	106.6
Income before provision for income taxes	437.9	441.8	416.2
Provision for income taxes	152.2	165.5	155.9
Net income	285.7	276.3	260.3
Other comprehensive income, net of tax			
Gain on cash flow hedges	0.8	3.5	0.7
Total other comprehensive income, net of tax	0.8	3.5	0.7
Comprehensive income	$ 286.5	$ 279.8	$ 261.0

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 December 31,*	*2016*	*2015*	*2014*
Cash flows from operating activities			
Net income	$ 285.7	$ 276.3	$ 260.3
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	328.3	313.5	302.6
Deferred income taxes and investment tax credits	87.7	118.9	92.2
Allowance for other funds used during construction	(24.1)	(17.2)	(10.5)
Deferred recovery clauses	54.4	26.5	(16.2)
Receivables, less allowance for uncollectibles	17.7	(3.0)	0.4
Inventories	16.0	(21.3)	13.1
Prepayments and other deposits	(0.1)	(4.0)	1.5
Taxes accrued	67.5	(17.2)	11.8
Interest accrued	(0.7)	(0.1)	0.6
Accounts payable	63.1	(26.8)	5.9
Other	(64.9)	(37.7)	(14.5)
Cash flows from operating activities	830.6	607.9	647.2
Cash flows from investing activities			
Capital expenditures	(726.8)	(686.6)	(671.0)
Net proceeds from sale of assets	9.1	0.0	0.0
Cash flows used in investing activities	(717.7)	(686.6)	(671.0)
Cash flows from financing activities			
Common stock	150.0	175.0	100.0
Proceeds from long-term debt issuance	0.0	251.1	296.3
Repayment of long-term debt	(83.3)	(83.3)	(83.3)
Net change in short-term debt	109.0	3.0	(26.0)
Dividends	(288.2)	(268.4)	(262.6)
Cash flows from/(used in) financing activities	(112.5)	77.4	24.4
Net increase (decrease) in cash and cash equivalents	0.4	(1.3)	0.6
Cash and cash equivalents at beginning of the year	9.1	10.4	9.8
Cash and cash equivalents at end of the year	$ 9.5	$ 9.1	$ 10.4
Supplemental disclosure of cash paid (received)			
Interest	$ 102.9	$ 106.2	$ 102.5
Income taxes	$ (3.0)	$ 63.7	$ 52.6
Supplemental disclosure of non-cash activities			
Change in accrued capital expenditures	$ (8.9)	$ 6.9	$ 14.3

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Retained Earnings

(millions) *For the years ended December 31,*	*2016*	*2015*	*2014*
Balance, beginning of year	$ 313.7	$ 305.8	$ 308.1
Add: Net income	285.7	276.3	260.3
	599.4	582.1	568.4
Deduct: Cash dividends on capital stock—common	288.2	268.4	262.6
Balance, end of year	$ 311.2	$ 313.7	$ 305.8

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 *December 31,* Shares	Amount	Cash Dividends Paid [1] Per Share	Amount
Common stock - without par value					
25 million shares authorized					
2016 [3]	N/A	10	$ 2,455.4	*(2)*	$ 288.2
2015 [3]	N/A	10	$ 2,305.4	*(2)*	$ 268.4

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 February 29, May 27, June 29 and November 10 during 2016.
Quarterly dividends paid on March 2, May 28, August 28 and November 30 during 2015.
(2) Not meaningful.
(3) TECO Energy made equity contributions to TEC of $150.0 million in 2016 and $175.0 million in 2015.

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Capitalization – continued

At December 31, 2016 and 2015, TEC had the following long-term debt outstanding:

Long-Term Debt

(millions)		*Due*	*2016*	*2015*
Tampa Electric	Installment contracts payable [1] :			
	5.65% Refunding bonds	2018	$ 54.2	$ 54.2
	Notes [2][3] : 6.25%	2016	0.0	83.3
	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	290.0
	4.20%	2045	230.0	230.0
	Total long-term debt of Tampa Electric		1,920.9	2,004.2
PGS	Notes [2][3] : 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	10.0
	4.20%	2045	20.0	20.0
	Total long-term debt of PGS		261.7	261.7
Total long-term debt of TEC			2,182.6	2,265.9
Unamortized debt discount, net			(3.0)	(2.8)
Debt issuance costs			(16.7)	(18.1)
Total carrying amount of long-term debt			2,162.9	2,245.0
Less amount due within one year			0.0	83.3
Total long-term debt			$ 2,162.9	$ 2,161.7

(1) Tax-exempt securities.
(2) These securities are subject to redemption in whole or in part, at any time, at the option of the issuer.
(3) 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 December 31, 2016, total long-term debt had a carrying amount of $2,162.9 million and an estimated fair market value of $2,345.3 million. At December 31, 2015, total long-term debt had a carrying amount of $2,245.0 million and an estimated fair market value of $2,433.3 million. TEC uses the market approach in determining fair value. The majority of the outstanding debt is valued using real-time financial market data. The remaining securities are valued using prices obtained from the Municipal Securities Rulemaking Board or by applying estimated credit spreads obtained from a third party to the par value of the security. The fair value of debt securities totaling $57.9 million is determined using Level 1 measurements; the fair value of the remaining debt securities is determined using Level 2 measurements (see **Note 14** for information regarding the fair value hierarchy).

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 2017 through 2021 and thereafter are as follows:

Long-Term Debt Maturities

As of December 31, 2016 (millions)	*2017*	*2018*	*2019*	*2020*	*2021*	*Thereafter*	*Total Long-Term Debt*
Tampa Electric	$ 0.0	254.2	$ 0.0	$ 0.0	$ 231.7	$ 1,435.0	$ 1,920.9
PGS	0.0	50.0	0.0	0.0	46.7	165.0	261.7
Total long-term debt maturities	$ 0.0	$ 304.2	$ 0.0	$ 0.0	$ 278.4	$ 1,600.0	$ 2,182.6

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

TAMPA ELECTRIC COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

Description of Business

TEC has two operating segments. Its Tampa Electric division provides retail electric services in West Central Florida, and PGS, the natural 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:

Principles of Consolidation and Basis of Presentation

TEC maintains its accounts in accordance with recognized policies prescribed or permitted by the FPSC and the FERC. These policies conform with U.S. GAAP in all material respects. The use of estimates is inherent in the preparation of financial statements in accordance with U.S. GAAP. Actual results could differ from these estimates.

TEC is a wholly-owned subsidiary of TECO Energy, Inc. and contains electric and natural gas divisions. Intercompany balances and transactions within the divisions have been eliminated in consolidation.

On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on September 4, 2015. As a result of the Merger, the Merger Sub Company merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera. The acquisition method of accounting was not pushed down to TECO Energy or its subsidiaries, including TEC. See **Note 8** for further information.

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.

Property, Plant and Equipment

Property, plant and equipment is stated at original cost, which includes labor, material, applicable taxes, overhead and AFUDC. Concurrent with a planned major maintenance outage or with new construction, the cost of adding or replacing retirement units-of-property is capitalized in conformity with the regulations of FERC and FPSC. The cost of maintenance, repairs and replacement of minor items of property is expensed as incurred.

In general, when regulated depreciable property is retired or disposed, its original cost less salvage is charged to accumulated depreciation. For other property dispositions, the cost and accumulated depreciation are removed from the balance sheet and a gain or loss is recognized.

Property, plant and equipment consisted of the following assets:

(millions)	*Estimated Useful Lives*	*December 31, 2016*	*December 31, 2015*
Electric generation	15-56 years	$ 4,101.8	$ 4,046.5
Electric transmission	28-77 years	836.8	711.2
Electric distribution	14-56 years	2,331.4	2,221.3
Gas transmission and distribution	16-77 years	1,429.1	1,326.1
General plant and other	3-43 years	438.8	373.5
Total cost		9,137.9	8,678.6
Less accumulated depreciation		(2,826.1)	(2,676.8)
Construction work in progress		891.5	771.1
Total property, plant and equipment, net		$ 7,203.3	$ 6,772.9

Depreciation

The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 3.5%, 3.7% and 3.7% for 2016, 2015 and 2014, respectively. Construction work in progress is not depreciated until the asset is completed or placed in service. Total depreciation expense for the years ended December 31, 2016, 2015 and 2014 was $303.6

million, $306.0 million and $295.8 million, respectively. See **Note 3** for information regarding an agreement approved by the FPSC that, among other things, reduced PGS's annual depreciation expense by $16.1 million in 2016.

Tampa Electric and PGS compute depreciation and amortization 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.

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. In 2016, 2015 and 2014, the rate was 6.46%. Total AFUDC for the years ended December 31, 2016, 2015 and 2014 was $35.6 million, $25.5 million and $15.6 million, respectively. The increase is a result of the construction of the Polk Power Station conversion project.

Inventory

TEC values materials, supplies and fossil fuel inventory (natural gas, coal and oil) 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 will be recovered with a normal profit upon sale in the ordinary course of business.

Regulatory Assets and Liabilities

Tampa Electric and PGS are subject to accounting guidance for the effects of certain types of regulation (see **Note 3**). TEC's retail and wholesale businesses are regulated by the FPSC and FERC, respectively. Prices allowed by both agencies are generally based on recovery of prudent costs incurred plus a reasonable return on invested capital.

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.

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.

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. See **Note 3** for a discussion of significant regulatory matters and the applicability of the accounting guidance for certain types of regulation to TEC.

The regulated utilities accrue base revenues for services rendered but unbilled to provide for matching of revenues and expenses (see **Note 3**). As of December 31, 2016 and 2015, unbilled revenues of $53.6 million and $53.7 million, respectively, are included in the "Receivables" line item on TEC's Consolidated Balance Sheets.

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.

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 $104.1 million, $78.9 million and $71.4 million, for the years ended December 31, 2016, 2015 and 2014, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost-recovery clause.

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 TEC's collection experience. Circumstances that could affect Tampa Electric's and PGS'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.

Accounting for Franchise Fees and Gross Receipts Taxes

TEC is allowed to recover certain costs on a dollar-for-dollar basis incurred from customers through rates 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 are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". These amounts totaled $116.9 million, $116.9 million and $113.9 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued postretirement and pension liabilities (see **Note 5**), MGP environmental remediation liability (see **Note 9**), asset retirement obligations (see **Note 16**), and medical and general liability claims incurred but not reported.

TECO Energy and its subsidiaries, including TEC, have a self-insurance program supplemented by excess insurance coverage for the cost of claims whose ultimate value exceeds the company's retention amounts. TEC 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 December 31, 2016 and 2015 ranged from 2.69% to 4.00% and 2.92% to 4.00%, respectively.

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. 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.

Reclassifications

Certain reclassifications were made to prior year amounts to conform to current period presentation. None of the reclassifications affected TEC's net income in any period. See **Note 2** for information regarding the reclassifications.

2. New Accounting Pronouncements

Change in Accounting Policy

The new U.S. GAAP accounting policies that are applicable to and were adopted by TEC are described as follows:

Interest – Imputation of Interest

In April 2015, the FASB issued Accounting Standard Update (ASU) 2015-03, *Interest – Imputation of Interest*, which simplifies the presentation of debt issuance costs. The amendments require debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts or premiums. The recognition and measurement guidance for debt issuance costs is not affected. TEC adopted this standard in the first quarter of 2016, and December 31, 2015 balances have been retrospectively restated. This change resulted in $18.1 million of debt issuance costs as of December 31, 2015, previously presented as “Deferred charges and other assets”, being reclassified as a deduction from the carrying amount of the related “Long-term debt, less amount due within one year” line item on its Consolidated Balance Sheet. In accordance with ASU 2015-15 *Interest: Imputation of Interest*, TEC continues to present debt issuance costs related to its letter of credit arrangements and related instruments in “Prepayments and other current assets” on its Consolidated Balance Sheets.

Derivatives and Hedging - Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships

In March 2016, the FASB issued ASU 2016-05, *Derivatives and Hedging Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships.* The standard clarifies that a change in the counterparty to a derivative contract, in and of itself, does not require the dedesignation of a hedging relationship provided that all other hedge accounting criteria continue to be met. TEC early adopted in 2016 as permitted.

Future Accounting Pronouncements

TEC considers the applicability and impact of all ASUs issued by FASB. The following updates have been issued by FASB but have not yet been adopted by TEC. Any ASUs not included below were assessed and determined to be either not applicable to TEC or to have minimal impact on the consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which creates a new principle-based revenue recognition framework, which has been codified as ASC Topic 606. The FASB issued amendments to ASC Topic 606 during 2016 to clarify certain implementation guidance and to reflect narrow scope improvements and practical expedients. 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 to. The guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue and related cash flows arising from contracts with customers. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017 and will allow for either full retrospective adoption or modified retrospective adoption. TEC will adopt this guidance effective January 1, 2018. TEC has implemented a project plan and is in the process of evaluating the impact of adoption of this standard on its consolidated financial statements and disclosures. This includes evaluating the available adoption methods, accounting for contributions in aid of construction and contract acquisition costs, and disclosure requirements. TEC is also monitoring the assessment of ASC Topic 606 by the AICPA Power and Utilities Revenue Recognition Task Force. While TEC does not currently expect the impact to be significant, the ultimate impact of the adoption of ASC Topic 606, and the method of adoption, has not yet been finalized.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments – Recognition and Measurement of Financial Assets and Financial Liabilities.* The standard provides guidance for the recognition, measurement, presentation and disclosure of financial assets and liabilities. TEC does not have equity investments or available-for-sale debt securities and it does not record financial liabilities under the fair value option. However, it is currently evaluating the impact of the adoption of this guidance on its financial statement disclosures. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017.

Leases

In February 2016, the FASB issued ASU 2016-02, *Leases.* The standard, codified as ASC Topic 842, increases transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with terms of more than 12 months. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. The effect of leases on the Consolidated Statements of Income and the Consolidated Statements of Cash Flows is largely unchanged. The guidance will require additional disclosures regarding key information about leasing arrangements. This guidance is effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2018. Early adoption is permitted, and is required to be applied using a modified retrospective approach. TEC is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments

In June 2016, the FASB issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments*. The standard provides guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted for annual reporting periods, including interim periods after December 15, 2018, and will be applied using a modified retrospective approach. TEC is currently evaluating the impact of adoption of this standard on its consolidated financial statements.

Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows

In August 2016, the FASB issued ASU 2016-15, *Classification of Certain Cash Receipts and Cash Payments on the Statement of Cash Flows*. The standard provides guidance regarding the classification of certain cash receipts and cash payments on the statement of cash flows, where specific guidance is provided for issues not previously addressed. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. TEC is currently evaluating the impact of adoption of this standard on its consolidated statement of cash flows.

Restricted Cash on the Statement of Cash Flows

In November 2016, the FASB issued ASU 2016-18, *Restricted Cash on the Statement of Cash Flows*. The standard will require TEC to show the changes in total cash, cash equivalents, restricted cash and restricted cash equivalents in the statement of cash flows. Transfers between cash and cash equivalents and restricted cash and restricted cash equivalents will no longer be presented in the statement of cash flows. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied on a retrospective approach. To date, TEC does not have any restricted cash or restricted cash equivalents.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, *Clarifying the Definition of a Business*. The standard provides guidance to assist entities with evaluating when a set of transferred assets and activities is a business. This guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2017, with early adoption permitted, and is required to be applied prospectively.

3. Regulatory

Tampa Electric's retail business and PGS are regulated separately by the FPSC. Tampa Electric is also subject to regulation by the FERC. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC sets rates based on a cost of service methodology which allows utilities 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 past three years reflect the results of a Stipulation and Settlement Agreement entered into on September 6, 2013, between Tampa Electric and the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric's 2013 base rate proceeding. On September 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 November 1, 2013, an additional $7.5 million effective November 1, 2014, an additional $5.0 million effective November 1, 2015, and an additional $110.0 million effective the date that the expansion of Tampa Electric's Polk Power Station went into service, which was January 16, 2017. The agreement also 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 base rate increases to be effective sooner than January 1, 2018, unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE were increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE were increased as described above) any party to the agreement other than Tampa Electric could seek a review of its 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 beginning on January 1, 2013.

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-Tampa Electric

Tampa Electric's storm reserve was $56.1 million at both December 31, 2016 and 2015. Prior to the above-mentioned stipulation and settlement agreement, Tampa Electric was accruing $8.0 million annually to an FPSC-approved self-insured storm damage reserve. Effective November 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 of the reserve as of October 31, 2013. As a result of several named storms including Tropical Storm Colin, Hurricane Hermine and Hurricane Matthew, Tampa Electric has incurred $8.6 million of storm costs in 2016. On January 31, 2017, Tampa Electric petitioned the FPSC to seek full recovery of those costs as a surcharge to customers during the five-month period ended December 31, 2017.

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 June 28, 2016, PGS filed its depreciation study with the FPSC seeking approval for new depreciation rates. After communications with the FPSC staff, on December 15, 2016, PGS and OPC filed a settlement with the FPSC agreeing to new depreciation rates that reduce annual depreciation expense by $16.1 million in 2016, accelerate the amortization of the regulatory asset associated with environmental remediation costs as described below, include obsolete plastic pipe replacements through the existing cast iron and bare steel replacement rider, and decrease the bottom of the ROE range from 9.75% to 9.25%. The new bottom of the range will remain until the earlier of new base rates established in PGS's next general base rate proceeding or December 31, 2020. The top of the range will continue to be 11.75%, and the ROE of 10.75% will continue to be used for the calculation of return on investment for clauses and riders. On February 7, 2017, the FPSC approved the settlement agreement. No change in customer rates resulted from this agreement.

As part of the settlement, PGS and OPC agreed that at least $32 million of PGS's regulatory asset associated with the environmental liability for current and future remediation costs related to former MGP sites, to the extent expenses are reasonably and prudently incurred, will be amortized over the period 2016 through 2020. At least $21 million will be amortized over a two-year recovery period beginning in 2016. In 2016, PGS recorded $16 million of this amortization expense. This additional amortization expense in 2016 was offset by the decrease in depreciation expense as discussed above with no impact to 2016 earnings.

Regulatory Assets and Liabilities

Tampa Electric and PGS apply the accounting standards for regulated operations. Areas of applicability include: 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; 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; and the advance recovery of expenditures for approved costs such as future storm damage or the future removal of property. All regulatory assets are recovered through the regulatory process.

Details of the regulatory assets and liabilities as of December 31, 2016 and 2015 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*December 31, 2016*	*December 31, 2015*
Regulatory assets:		
Regulatory tax asset (1)	$ 85.6	$ 74.6
Cost-recovery clauses - deferred balances (2)	8.4	5.2
Cost-recovery clauses - offsets to derivative liabilities (2)	0.0	26.2
Environmental remediation (3)	36.9	54.0
Postretirement benefits (4)	272.0	238.3
Deferred bond refinancing costs (5)	5.7	6.5
Competitive rate adjustment (2)	2.7	2.6
Other	9.4	10.7
Total regulatory assets	420.7	418.1
Less: Current portion	28.1	44.3
Long-term regulatory assets	$ 392.6	$ 373.8
Regulatory liabilities:		
Regulatory tax liability	$ 6.2	$ 5.7
Cost-recovery clauses (2)	111.8	54.2
Transmission and delivery storm reserve	56.1	56.1
Accumulated reserve—cost of removal (6)	546.4	570.0
Other	24.3	0.7
Total regulatory liabilities	744.8	686.7
Less: Current portion	154.2	83.2
Long-term regulatory liabilities	$ 590.6	$ 603.5

(1) The regulatory tax asset is primarily associated with the depreciation and recovery of AFUDC-equity. This asset does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be recovered over the expected life of the related assets.

(2) These assets and liabilities are related to FPSC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC on a dollar-for-dollar basis in the next year. In the case of the regulatory asset related to derivative liabilities, recovery occurs in the year following the settlement of the derivative position.

(3) This asset is related to costs associated with environmental remediation primarily at MGP sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is based on a settlement agreement approved by the FPSC.

(4) This asset is related to the deferred costs of postretirement benefits and it is amortized over the remaining service life of plan participants. Deferred costs of postretirement benefits that are included in expense are recognized as cost of service for rate-making purposes as permitted by the FPSC.

(5) This asset represents the past costs associated with refinancing debt. It does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be amortized over the term of the related debt instruments.

(6) This item represents the non-ARO cost of removal in the accumulated reserve for depreciation. AROs are costs for legally required removal of property, plant and equipment. Non-ARO cost of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment, net of salvage value upon retirement, which reduces rate base for ratemaking purposes. This liability is reduced as costs of removal are incurred.

4. Income Taxes

Income Tax Expense

Effective July 1, 2016 and due to the Merger with Emera, TEC is included in a consolidated U.S. federal income tax return with EUSHI and its subsidiaries. Prior to the Merger, TEC was included in the filing of a consolidated federal income tax return with TECO Energy and its subsidiaries. TEC's income tax expense is based upon a separate return method, modified for the benefits-for-loss allocation in accordance with respective tax sharing agreements of TECO Energy and EUSHI. To the extent that TEC's cash tax positions are settled differently than the amount reported as realized under the tax sharing agreement, the difference is accounted for as either a capital contribution or a distribution.

In 2016, 2015 and 2014, TEC recorded net tax provisions of $152.2 million, $165.5 million and $155.9 million, respectively.

Income tax expense consists of the following components:

Income Tax Expense (Benefit)

(millions) *For the year ended December 31,*		*2016*		*2015*		*2014*
Current income taxes						
Federal	$	52.7	$	38.2	$	54.8
State		11.8		8.4		8.9
Deferred income taxes						
Federal		75.7		102.9		79.0
State		11.0		14.5		13.5
Investment tax credits, net of amortization		1.0		1.5		(0.3)
Total income tax expense	$	152.2	$	165.5	$	155.9

For the three years presented, the overall effective tax rate differs from the 35% U.S. federal statutory rate as presented below:

Effective Income Tax Rate

(millions) *For the year ended December 31,*		*2016*		*2015*		*2014*
Income before provision for income taxes	$	437.9	$	441.8	$	416.2
Federal statutory income tax rates		35%		35%		35%
Income taxes, at statutory income tax rate		153.3		154.6		145.7
Increase (decrease) due to						
State income tax, net of federal income tax		14.8		14.8		14.5
AFUDC-equity		(8.4)		(6.0)		(3.7)
Tax credits		(6.8)		0.0		0.0
Other		(0.7)		2.1		(0.6)
Total income tax expense on consolidated statements of income	$	152.2	$	165.5	$	155.9
Income tax expense as a percent of income from continuing operations, before income taxes		34.8%		37.5%		37.5%

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 December 31,*		*2016*		*2015*
Deferred tax liabilities (1)				
Property related	$	1,549.1	$	1,431.9
Pension and postretirement benefits		105.0		92.0
Pension		69.2		71.1
Total deferred tax liabilities		1,723.3		1,595.0
Deferred tax assets (1)				
Loss and credit carryforwards (2)		91.3		80.0
Medical benefits		46.9		47.7
Insurance reserves		27.3		27.6
Pension and postretirement benefits		105.0		92.0
Capitalized energy conservation assistance costs		22.9		21.4
Other		23.3		17.5
Total deferred tax assets		316.7		286.2
Total deferred tax liability, net	$	1,406.6	$	1,308.8

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

(2) Deferred tax assets for net operating loss and tax credit carryforwards have been reduced by unrecognized tax benefits of $6.8 million.

At December 31, 2016, TEC had cumulative unused federal and Florida NOLs for income tax purposes of $202.8 million and $272.6 million, respectively, expiring between 2033 and 2036. TEC has unused general business credits of $10.0 million, expiring between 2028 and 2036. As a result of the Merger with Emera, TECO Energy's NOLs and credits will be utilized by EUSHI, in accordance with the benefits-for-loss allocation which provide that tax attributes are utilized by the consolidated tax return group of EUSHI.

Unrecognized Tax Benefits

TEC accounts for uncertain tax positions as required by U.S. GAAP. 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. Authoritative guidance related to accounting for uncertainty in income taxes requires an enterprise to recognize in its financial statements the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates that it is more likely than not, based solely on the technical merits, that the position will be sustained upon examination, including resolution of any related appeals and litigation processes.

The following table provides details of the change in unrecognized tax benefits as follows:

(millions)	*2016*	*2015*	*2014*
Balance at January 1,	$ 0.0	$ 0.0	$ 0.0
Increases due to tax positions related to current year	6.8	0.0	0.0
Balance at December 31	$ 6.8	$ 0.0	$ 0.0

As of December 31, 2016 and 2015, TEC's uncertain tax positions were $6.8 million and zero, respectively, all of which was recorded as a reduction of deferred income tax assets for tax credit carryforwards. The increase was due to an uncertain tax position related to federal R&D tax credits. TEC believes that the total unrecognized tax benefits will decrease within the next twelve months due to the expected audit examination of TECO Energy's consolidated federal income tax return for the short tax year ending June 30, 2016. As of December 31, 2016, if recognized, $6.8 million of the unrecognized tax benefits would reduce TEC's effective tax rate.

TEC recognizes interest accruals related to uncertain tax positions in "Other income" or "Interest expense", as applicable, and penalties in "Operation and maintenance other expense" in the Consolidated Statements of Income. In 2016, 2015 and 2014, TEC did not recognize any pretax charges (benefits) for interest. Additionally, TEC did not have any accrued interest at December 31, 2016, 2015 and 2014. No amounts have been recorded for penalties.

Years 2015 and the short tax year ending June 30, 2016 are currently under examination by the IRS under its Compliance Assurance Program (CAP). Prior to July 1, 2016, TEC was included in a consolidated U.S. federal income tax return with TECO Energy and subsidiaries. Due to the Merger with Emera, TECO Energy is only able to participate in the CAP through its short tax year ending June 30, 2016. The U.S. federal statute of limitations remains open for the year 2013 and onward. 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.

5. Employee Postretirement Benefits

Pension Benefits

TEC is a participant in the comprehensive retirement plans of TECO Energy, including a qualified, 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.

Amounts disclosed for pension benefits in the following tables and discussion also include the fully-funded obligations for the SERP, which 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. TECO Energy 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 at the time 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 and its affiliates do not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase the 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 January 1, 2013, TECO Energy implemented 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 TECO Energy under Medicare Part D for its post-65 retiree prescription drug plan. Effective January 1, 2015, TECO Energy changed its 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.

Obligations and Funded Status

TEC recognizes in its statement of financial position the over-funded or under-funded status of its allocated portion of TECO Energy's 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.

The following table provides a detail of the change in TECO Energy's benefit obligations and change in plan assets for combined pension plans (pension benefits) and TECO Energy's Florida-based other postretirement benefit plan (other benefits).

TECO Energy **Obligations and Funded Status**	**Pension Benefits**		**Other Benefits** [2]	
(millions)	*2016*	*2015*	*2016*	*2015*
Change in benefit obligation				
Net benefit obligation at beginning of year	$ 732.9	$ 728.9	$ 172.3	$ 174.3
Service cost	18.8	20.9	1.8	1.9
Interest cost	30.8	30.3	7.4	7.0
Plan participants' contributions	0.0	0.0	2.6	2.1
Plan amendments	1.2	0.0	0.0	0.0
Plan curtailment	1.3	0.0	0.0	0.0
Plan settlement	(2.1)	0.0	0.0	0.0
Benefits paid	(69.5)	(53.0)	(13.9)	(13.4)
Actuarial loss (gain)	56.3	5.8	5.0	0.4
Net benefit obligation at end of year	$ 769.7	$ 732.9	$ 175.2	$ 172.3

Change in plan assets				
Fair value of plan assets at beginning of year	$ 625.4	$ 648.0	$ 0.0	$ 0.0
Actual return on plan assets	55.3	(25.5)	0.0	0.0
Employer contributions	37.4	55.0	(2.6)	(2.1)
Employer direct benefit payments	2.9	0.9	13.9	13.4
Plan participants' contributions	0.0	0.0	2.6	2.1
Plan settlement	(2.1)	0.0	0.0	0.0
Benefits paid	(68.7)	(53.0)	(13.9)	(13.4)
Direct benefit payments	(0.8)	0.0	0.0	0.0
Fair value of plan assets at end of year (1)	$ 649.4	$ 625.4	$ 0.0	$ 0.0

(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.
(2) Represent amounts for TECO Energy's Florida-based other postretirement benefit plan.

At December 31, the aggregate financial position for TECO Energy pension plans and Florida-based other postretirement plans with benefit obligations in excess of plan assets was as follows:

TECO Energy	**Pension Benefits**		**Other Benefits (1)**	
Funded Status				
(millions)	*2016*	*2015*	*2016*	*2015*
Benefit obligation (PBO/APBO)	$ 769.7	$ 732.9	$ 175.2	$ 172.3
Less: Fair value of plan assets	649.4	625.4	0.0	0.0
Funded status at end of year	$ (120.3)	$ (107.5)	$ (175.2)	$ (172.3)

(1) Represent amounts for TECO Energy's Florida-based other postretirement benefit plan.

The accumulated benefit obligation for TECO Energy consolidated defined benefit pension plans was $723.9 million at December 31, 2016 and $686.9 million at December 31, 2015.

The amounts recognized in TEC's Consolidated Balance Sheets for pension and other postretirement benefit obligations and plan assets at December 31 were as follows:

TEC	**Pension Benefits**		**Other Benefits**	
Amounts recognized in balance sheet				
(millions)	*2016*	*2015*	*2016*	*2015*
Accrued benefit costs and other current liabilities	$ (0.7)	$ (0.6)	$ (9.5)	$ (9.2)
Deferred credits and other liabilities	(80.0)	(69.3)	(138.8)	(142.3)
	$ (80.7)	$ (69.9)	$ (148.3)	$ (151.5)

Unrecognized gains and losses and prior service credits and costs are recorded in regulatory assets for TEC. The following table provides a detail of the unrecognized gains and losses and prior service credits and costs.

TEC	**Pension Benefits**		**Other Benefits**	
Amounts recognized in regulatory assets				
(millions)	*2016*	*2015*	*2016*	*2015*
Net actuarial loss (gain)	$ 236.1	$ 208.2	$ 50.5	$ 47.2
Prior service cost (credit)	0.7	0.0	(15.1)	(17.0)
Amount recognized	$ 236.8	$ 208.2	$ 35.4	$ 30.2

Assumptions used to determine benefit obligations at December 31:

	Pension Benefits		Other Benefits	
	2016	*2015*	*2016*	*2015*
Discount rate	4.11%	4.688%	4.28%	4.667%
Rate of compensation increase-weighted average	2.57%	3.87%	2.48%	2.50%
Healthcare cost trend rate				
Immediate rate	n/a	n/a	6.83%	7.05%
Ultimate rate	n/a	n/a	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	2038	2038

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 PBO	$ 4.9	$ (4.2)

The discount rate assumption used to determine the December 31, 2016 benefit obligation was based on a cash flow matching technique that matches yields from high-quality (AA-rated, non-callable) corporate bonds to TECO Energy's projected cash flows for the plans to develop a present value that is converted to a discount rate assumption. The discount rate assumption used to determine the December 31, 2015 benefit obligation was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructed 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 calculated all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selected the portfolio with the highest yield and used that yield as the recommended discount rate. The change in the discount rate approach was a result of the Merger and done to align methodologies with Emera. The change in discount rate resulting from the different methodology used to select a discount rate did not have a material impact on TEC's financial statements and provides consistency with Emera's method for selecting a discount rate.

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

TECO Energy	Pension Benefits			Other Benefits (1)		
	2016	*2015*	*2014*	*2016*	*2015*	*2014*
(millions)						
Service cost	$ 18.8	$ 20.9	$ 18.3	$ 1.8	$ 1.9	$ 2.4
Interest cost	30.8	30.3	32.0	7.4	7.0	10.4
Expected return on plan assets	(45.8)	(43.3)	(41.8)	0.0	0.0	0.0
Amortization, settlement, or curtailment of:						
Actuarial loss	16.4	15.1	13.5	0.2	0.0	0.2
Prior service (benefit) cost	0.3	(0.2)	(0.4)	(2.4)	(2.4)	(0.2)
Curtailment loss (gain)	1.3	0.0	3.9	0.0	0.0	(0.2)
Special termination benefit	0.0	0.0	0.2	0.0	0.0	0.0
Settlement loss	0.6	0.0	0.0	0.0	0.0	0.0
Net periodic benefit cost	$ 22.4	$ 22.8	$ 25.7	$ 7.0	$ 6.5	$ 12.6
New prior service cost	$ 1.3	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ (23.2)
Net loss (gain) arising during the year	46.8	74.5	44.1	5.0	0.4	(10.1)
Amounts recognized as component of net periodic benefit cost:						
Amortization or curtailment recognition of prior service (benefit) cost	(0.3)	0.2	0.4	2.4	2.5	0.3
Amortization or settlement of actuarial gain (loss)	(17.1)	(15.1)	(13.5)	(0.2)	0.0	(0.2)
Total recognized in OCI and regulatory assets	$ 30.7	$ 59.6	$ 31.0	$ 7.2	$ 2.9	$ (33.2)
Total recognized in net periodic benefit cost, OCI and regulatory assets	$ 53.1	$ 82.4	$ 56.7	$ 14.2	$ 9.4	$ (20.6)

(1) Represent amounts for TECO Energy's Florida-based other postretirement benefit plan.

TEC's portion of the net periodic benefit costs for pension benefits was $13.3 million, $13.5 million and $14.8 million for 2016, 2015 and 2014, respectively. TEC's portion of the net periodic benefit costs for other benefits was $6.4 million, $5.7 million and $10.4 million for 2016, 2015 and 2014, respectively.

The estimated net loss 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 is $12.7 million. There will be an estimated $1.8 million prior service credit that will be amortized from regulatory assets into net periodic benefit cost in 2017 for the other postretirement benefit plan.

TEC's postretirement benefit plans were not explicitly impacted by the Merger. However, as a result of the Merger, TECO Energy remeasured its postretirement benefits plans on the Merger effective date, July 1, 2016. As a result of the remeasurements, TEC's net periodic benefit cost increased by $1.0 million for pension benefits and $0.4 million for other postretirement plan benefits for the six months ended December 31, 2016. Additionally, a curtailment loss for the SERP of $1.3 million was recognized by TECO Energy in 2016 as a result of retirements due to the Merger. TEC was not impacted by the curtailment loss.

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

	Pension Benefits			**Other Benefits**		
	2016	*2015*	*2014* (1)	*2016*	*2015*	*2014*
Discount rate	4.688%	4.258%	5.118%/4.277%/4.331%	4.667%/3.85%	4.206%	5.096%
Expected long-term return on plan assets	7.00%	7.00%	7.25%/7.00%/7.00%	N/A	N/A	N/A
Rate of compensation increase	2.59%	3.87%	3.73%	2.50%	3.86%	3.71%
Healthcare cost trend rate						
Initial rate	n/a	n/a	n/a	7.05%	7.00%	7.25%
Ultimate rate	n/a	n/a	n/a	4.50%	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	n/a	2038	2025	2025

(1) TECO Energy performed a valuation as of January 1, 2014. TECO Energy remeasured its Retirement Plan on September 2, 2014 for the acquisition of NMGC and on October 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 benefit cost from the Merger date to December 31, 2016 was based on a cash flow matching technique that matches yields from high-quality (AA-rated, non-callable) corporate bonds to TECO Energy's projected cash flows for the plans to develop a present value that is converted to a discount rate assumption. The discount rate assumption used to determine the January 1, 2016 through June 30, 2016 and the 2015 benefit cost was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructed 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 calculated all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selected the portfolio with the highest yield and uses that yield as the recommended discount rate. The change in the discount rate approach was a result of the Merger and done to align methodologies with Emera. The change in discount rate resulting from the different methodology used to select a discount rate did not have a material impact on TEC's financial statements and provides consistency with Emera's method for selecting a 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 December 31, 2016, TECO Energy's pension plan's assets increased approximately 9.2%.

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 net periodic benefit cost	$ 0.2	$ (0.2)

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.

TECO Energy	**2016**		
	Target Allocation	**Actual Allocation, End of Year**	
Asset Category		*2016*	*2015*
Equity securities	52%-58%	56%	53%
Fixed income securities	42%-48%	44%	47%
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). Investments are valued using quoted market prices on an exchange when available. Such investments are classified Level 1. In some cases where a market exchange price is available but the investments are traded in a secondary market, acceptable practical expedients are used to calculate fair value.

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 December 31, 2016 and 2015.

Pension Plan Investments

TECO Energy *(millions)*	**At Fair Value as of December 31, 2016**				
	Level 1	**Level 2**	**Level 3**	**NAV [1]**	**Total**
Cash	$ 2.1	$ 0.0	$ 0.0	$ 0.0	$ 2.1
Accounts receivable	27.4	0.0	0.0	0.0	27.4
Accounts payable	(58.9)	0.0	0.0	0.0	(58.9)
Cash collateral	1.0	0.0	0.0	0.0	1.0
Short-term investment funds (STIFs)	11.6	0.0	0.0	0.0	11.6
Common stocks	44.0	0.0	0.0	0.0	44.0
Real estate investment trusts (REITs)	3.4	0.0	0.0	0.0	3.4
Mutual funds	181.1	0.0	0.0	0.0	181.1
Municipal bonds	0.0	2.6	0.0	0.0	2.6
Government bonds	0.0	32.2	0.0	0.0	32.2
Corporate bonds	0.0	39.2	0.0	0.0	39.2
Asset backed securities (ABS)	0.0	0.3	0.0	0.0	0.3
Mortgage-backed securities (MBS)	0.0	8.4	0.0	0.0	8.4
Collateralized mortgage obligations (CMOs)	0.0	1.3	0.0	0.0	1.3
Swaps	0.0	1.0	0.0	0.0	1.0
Purchase options (swaptions)	0.0	1.7	0.0	0.0	1.7
Written options (swaptions)	0.0	(2.0)	0.0	0.0	(2.0)
Miscellaneous (open position)	0.0	0.1	0.0	0.0	0.1
Investments not utilizing the practical expedient	211.7	84.8	0.0	0.0	296.5
Mutual fund [1]	0.0	0.0	0.0	82.7	82.7
Common and collective trusts [1]	0.0	0.0	0.0	270.2	270.2
Total investments	$ 211.7	$ 84.8	0.0	$ 352.9	$ 649.4

(1) In accordance with accounting standards, certain investments that are measured at fair value using the net asset value per share practical expedient have not been classified in the fair value hierarchy. The fair value amounts in this table are to permit reconciliation of the fair value hierarchy to amounts presented in the Consolidated Balance Sheet.

TECO Energy (millions)	At Fair Value as of December 31, 2015				
	Level 1	Level 2	Level 3	NAV [1]	Total
Cash	$ 1.9	$ 0.0	$ 0.0	$ 0.0	$ 1.9
Accounts receivable	14.3	0.0	0.0	0.0	14.3
Accounts payable	(27.2)	0.0	0.0	0.0	(27.2)
Money markets	0.0	0.2	0.0	0.0	0.2
Discounted notes	0.0	0.7	0.0	0.0	0.7
STIFs	12.4 [2]	0.0	0.0	0.0	12.4
Common stocks	90.9	0.0	0.0	0.0	90.9
ADRs	5.7	0.0	0.0	0.0	5.7
REITs	4.8	0.0	0.0	0.0	4.8
Mutual funds	175.6 [2]	0.0	0.0	0.0	175.6
Municipal bonds	0.0	5.0	0.0	0.0	5.0
Government bonds	0.0	56.2	0.0	0.0	56.2
Corporate bonds	0.0	32.2	0.0	0.0	32.2
ABS	0.0	0.3	0.0	0.0	0.3
MBS, net short sales	0.0	8.7	0.0	0.0	8.7
CMOs	0.0	1.5	0.0	0.0	1.5
Purchased options (swaptions)	0.0	1.1	0.0	0.0	1.1
Miscellaneous	0.0	0.1	0.0	0.0	0.1
Long futures	0.0	(0.9)	0.0	0.0	(0.9)
Written options (swaptions)	0.0	(1.0)	0.0	0.0	(1.0)
Investments not utilizing the practical expedient	278.4	104.1	0.0	0.0	382.5
Common and collective trusts [1]	0.0	0.0	0.0	171.6 [2]	171.6
Mutual fund [1]	0.0	0.0	0.0	71.3	71.3
Total investments	$ 278.4	$ 104.1	$ 0.0	$ 242.9	$ 625.4

(1) In accordance with accounting standards, certain investments that are measured at fair value using the net asset value per share practical expedient have not been classified in the fair value hierarchy. The fair value amounts in this table are to permit reconciliation of the fair value hierarchy to amounts presented in the Consolidated Balance Sheet.
(2) STIFs and mutual funds were presented in the prior year as using NAV as a practical expedient in the determination of fair value. Common and collective trust investments of $53.7 million were presented in the prior year in the level 2 column. The presentation has been updated based on additional information that became available in 2016.

The following list details the pricing inputs and methodologies used to value the investments in the pension plan:

- Cash collateral is valued at cash posted due to its short-term nature.
- The STIF is valued at net asset value (NAV). The fund is an open-end investment, resulting in a readily-determinable fair value. Additionally, 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. These factors make the STIF a level 1 asset.
- The primary pricing inputs in determining the fair value of the Common stocks and REITs are closing quoted prices in active markets.
- 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. Since the fair values are determined and published, they are considered readily-determinable fair values and therefore Level 1 assets.
- The primary pricing inputs in determining the fair value of 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 to-be-announced (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.
- Swaps are valued using benchmark yields, swap curves, and cash flow analyses.
- Options are valued using the bid-ask spread and the last price.
- The primary pricing input in determining the fair value of the mutual fund utilizing the practical expedient is its NAV. It is an unregistered open-ended mutual fund. The fund holds primarily corporate bonds, debt securities and other similar instruments issued by U.S. and non-U.S. public- or private-sector entities. The fund may purchase or sell securities on a when-issued

basis. These transactions are made conditionally because a security has not yet been issued in the market, although it is authorized. A commitment is made regarding these transactions to purchase or sell securities for a predetermined price or yield, with payment and delivery taking place beyond the customary settlement period. Since this mutual fund is a closed-end mutual fund and the prices are not published to an external source, it uses NAV as a practical expedient.

- The common collective trusts are private funds valued at NAV. The NAVs are calculated based on bid prices of the underlying securities. Since the prices are not published to external sources, NAV is used as a practical expedient. Certain funds invest primarily in equity securities of domestic and foreign issuers while others invest 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 funds honor subscription and redemption activity regularly.
- Discounted notes are valued at amortized cost.
- Treasury bills are valued using benchmark yields, reported trades, broker dealer quotes, and benchmark securities.
- Futures are valued using futures data, cash rate data, swap rates, and cash flow analyses.

Additionally, the unqualified SERP had $40.8 million and $43.5 million of assets as of December 31, 2016 and 2015, respectively. Since the plan is unqualified, its assets are included in the "Deferred charges and other assets" line item in TEC's Consolidated Balance Sheets rather than being netted with the related liability. The unqualified trust holds investments in a money market fund. The fund is an open-end investment, resulting in a readily-determinable fair value. Additionally, 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. These factors make it a level 1 asset. The SERP was fully funded as of December 31, 2016.

Other Postretirement Benefit Plan Assets

There are no assets associated with TECO Energy's Florida-based other postretirement benefits plan.

Contributions

The Pension Protection Act became effective January 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 December 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, HAFTA was signed into law, 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. In November 2015, the Bipartisan Budget Act of 2015 was signed into law, which extended pension funding relief of MAP-21 and HAFTA through 2022.

The qualified pension plan's actuarial value of assets, including credit balance, was 119.5% of the Pension Protection Act funded target as of January 1, 2016 and is estimated at 118.0% of the Pension Protection Act funded target as of January 1, 2017.

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. TEC's contribution is first set equal to its service cost. If a contribution in excess of service cost for the year is made, TEC's portion is based on TEC's proportion of the TECO Energy unfunded liability. TECO Energy made contributions to this plan in 2016 and 2015, which met the minimum funding requirements for both 2016 and 2015. TEC's portion of the contribution in 2016 was $30.9 million and in 2015 was $43.9 million. These amounts are reflected in the "Other" line on the Consolidated Statements of Cash Flows. TEC estimates its portion of the 2017 contribution to be $36.3 million. TEC estimates its portion of annual contributions from 2018 to 2021 will range from $0.5 to $29.5 million per year based on current assumptions. The amounts TECO Energy expects to make are in excess of the minimum funding required under ERISA guidelines.

TEC's portion of the contributions to the SERP in 2016 and 2015 were zero and $14.9 million, respectively. TEC's contribution in 2015 to the SERP's trust was made in order to fully fund its SERP obligation following the signing of the Merger Agreement with Emera. The execution of the Merger Agreement constituted a potential change in control under the trust; therefore, TECO Energy is required to maintain such funding as of the end of each calendar year, including 2016. The fully-funded amount is equal to the aggregate present value of all benefits then in pay status under the SERP plus the current value of benefits that would become payable under the SERP to current participants. Since the SERP is fully funded, TECO Energy does not expect to make significant contributions to this plan in 2017.

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 January 1, 1990 and June 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 2017, TEC expects to make a contribution of about $9.5 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
2017	$ 78.3	$ 11.0
2018	51.8	11.2
2019	55.6	11.5
2020	56.1	11.6
2021	58.7	11.7
2022-2026	312.4	58.9

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 January 1, 2015, the employer matching contributions were 70% of eligible participant contributions with additional incentive match of up to 30% of eligible participant contributions based on the achievement of certain operating company financial goals. During the period from April 2013 to December 2014, employer matching contributions were 67% 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% of eligible participant contributions based on the achievement of certain operating company financial goals. For the years ended December 31, 2016, 2015 and 2014, TEC's portion of expense totaled $8.3 million, $7.5 million and $10.2 million for 2016, 2015 and 2014, respectively, related to the matching contributions made to this plan.

6. Short-Term Debt

Credit Facilities

	December 31, 2016			*December 31, 2015*		
(millions)	Credit Facilities	Borrowings Outstanding (1)	Letters of Credit Outstanding	Credit Facilities	Borrowings Outstanding (1)	Letters of Credit Outstanding
5-year facility (2)	$ 325.0	$ 40.0	$ 0.5	$ 325.0	$ 0.0	$ 0.5
3-year accounts receivable facility (3)	150.0	130.0	0.0	150.0	61.0	0.0
Total	$ 475.0	$ 170.0	$ 0.5	$ 475.0	$ 61.0	$ 0.5

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures December 17, 2018.
(3) This 3-year facility matures March 23, 2018.

At December 31, 2016, 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 December 31, 2016 and 2015 was 1.49% and 0.89%, respectively.

Tampa Electric Company Accounts Receivable Facility

On March 24, 2015, TEC amended its $150 million accounts receivable collateralized borrowing facility in order to (i) appoint The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch (BTMU), as Program Agent, replacing the previous Program Agent, Citibank, N.A., (ii) add new lenders, and (iii) extend the scheduled termination date from April 14, 2015 to March 23, 2018, by entering into (a) an Amended and Restated Purchase and Contribution Agreement dated as of March 24, 2015 and (b) a Loan and Servicing Agreement dated as of March 24, 2015, among TEC and certain lenders named therein and BTMU, as Program Agent (the Loan Agreement). Pursuant to the Loan Agreement, TEC will pay program and liquidity fees, which total 65 basis points as of December 31, 2016. Interest rates on the borrowings are based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to, at TEC's option, either the BTMU's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank deposit rate (if available) plus a margin. In addition, under the terms of the Loan Agreement, TEC has pledged as collateral a pool of receivables equal to the borrowings outstanding in the case of default. TEC continues to service, administer and collect the pledged receivables, which are classified as receivables on the balance sheet. As of December 31, 2016, TEC was in compliance with the requirements of the Loan Agreement.

Amendment of Tampa Electric Company Credit Facility

On December 17, 2013, TEC amended 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 October 25, 2016 to December 17, 2018 (subject to further extension with the consent of each lender); (ii) continues to allow TEC, as borrower, 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 September 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 4.20% Notes due 2045

On May 20, 2015, TEC completed an offering of $250 million aggregate principal amount of 4.20% Notes due May 15, 2045 (the TEC 2015 Notes). Until November 15, 2044, TEC may redeem all or any part of the TEC 2015 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 the TEC 2015 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the TEC 2015 Notes to be redeemed, discounted at an applicable treasury rate (as defined in the indenture), plus 20 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after November 15, 2044, TEC may, at its option, redeem the TEC 2015 Notes, in whole or in part, at 100% of the principal amount of the TEC 2015 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

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). TEC may redeem all or any part of the TEC 2014 Notes at its option at any time and from time to time before November 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 November 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

At December 31, 2016, $232.6 million of tax-exempt bonds purchased in lieu of redemption were held by the trustee at the direction of Tampa Electric to provide an opportunity to evaluate refinancing alternatives including $20 million variable rate bonds due 2020, $51.6 million term-rate refunding bonds due 2025, $75.0 million term-rate bonds due 2030, and $86.0 million term-rate refunding bonds due 2034.

8. Merger with Emera Inc.

As disclosed in **Note 1,** TEC is a wholly owned subsidiary of TECO Energy. On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on September 4, 2015. Therefore, TEC continues to be a wholly owned subsidiary of TECO Energy and became an indirect wholly owned subsidiary of Emera as of July 1, 2016.

Pursuant to the Merger Agreement, upon the closing of the Merger, each issued and outstanding share of TECO Energy common stock was cancelled and converted automatically into the right to receive $27.55 in cash, without interest. This represents an aggregate purchase price of approximately $10.7 billion including Emera's purchase price allocation for debt of approximately $4.2 billion (of which TEC's portion of debt was $2.3 billion).

The Merger Agreement requires Emera, among other things, (i) to maintain TECO Energy's historic levels of community involvement and charitable contributions and support in TECO Energy's existing service territories, (ii) to maintain TECO Energy's and TEC's headquarters in Tampa, Florida, (iii) to honor current union contracts in accordance with their terms and (iv) to provide each continuing non-union employee, for a period of two years following the closing of the Merger, with a base salary or wage rate no less favorable than, and incentive compensation and employee benefits, respectively, substantially comparable in the aggregate to those that they received as of immediately prior to the closing.

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. TEC believes the claims in the pending actions described below are without merit and intends to defend the matters vigorously.

PGS Legal Proceeding

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, a suit was 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. The suit against PGS remains pending. No trial date is currently set. TEC is unable at this time to estimate the possible loss or range of loss with respect to this matter. While the outcome of such proceeding is uncertain, management does not believe that its ultimate resolution will have a material adverse effect on TEC's results of operations, financial condition or cash flows.

PGS Compliance Matter

In 2015, FPSC staff presented PGS with a summary of alleged safety rule violations, many of which were identified during PGS's implementation of an action plan it instituted as a result of audit findings cited by FPSC audit staff in 2013. Following the 2013 audit and 2015 discussions with FPSC staff, PGS took immediate and significant corrective actions. The FPSC audit staff published a follow-up audit report that acknowledged the progress that had been made and found that further improvements were needed. As a result of this report, the OPC filed a petition with the FPSC pointing to the violations of rules for safety inspections seeking fines or possible refunds to customers by PGS. On February 25, 2016, the FPSC staff issued a notice informing PGS that the staff would be making a recommendation to the FPSC to initiate a show cause proceeding against PGS for alleged safety rule violations, with total potential penalties of up to $3.9 million. On April 18, 2016, PGS reached a settlement regarding this matter with the OPC and FPSC staff and agreed to pay a $1 million civil penalty and customer refunds of $2 million. The FPSC approved the settlement agreement on May 5, 2016.

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 MGP sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of December 31, 2016, TEC has estimated its ultimate financial liability to be $31.6 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Deferred credits and other liabilities" on the Consolidated Condensed Balance Sheets. The environmental remediation costs associated with these sites are expected to be paid over many years.

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. See **Note 3** for information regarding an agreement approved by the FPSC to accelerate the amortization of the regulated asset associated with this reserve.

Long-Term Commitments

TEC has commitments for purchased power and long-term leases, primarily for building space, 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 December 31, 2016, 2015 and 2014, totaled $1.8 million, $3.8 million and $4.1 million, respectively. TEC also has other purchase obligations for long-term service agreements and capital projects. In addition, TEC has payment obligations under contractual agreements for fuel, fuel transportation and power purchases that are recovered from customers under regulatory clauses. The following is a schedule of future payments under PPAs, minimum lease payments with non-cancelable lease terms in excess of one year, and other net purchase obligations/commitments at December 31, 2016:

(millions)	*Purchased Power*	*Operating Leases*	*Long-term Service Agreements/Capital Projects*	*Clause Recoverable Commitments*	*Total*
Year ended December 31:					
2017	$ 10.7	$ 7.0	$ 68.8	$ 398.5	$ 485.0
2018	10.1	3.5	11.1	231.0	255.7
2019	0.0	2.1	11.8	186.2	200.1
2020	0.0	2.1	6.8	162.9	171.8
2021	0.0	2.2	6.9	132.3	141.4
Thereafter	0.0	37.8	24.4	1,156.6	1,218.8
Total future minimum payments	$ 20.8	$ 54.7	$ 129.8	$ 2,267.5	$ 2,472.8

Financial Covenants

TEC must meet certain financial tests, including a debt to capital ratio, as defined in the applicable banking agreements. TEC has certain restrictive covenants in specific agreements and debt instruments. At December 31, 2016, 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)	*2016*	*2015*	*2014*
Natural gas sales	$ 0.1	$ 0.8	$ 0.3
Services received from affiliates	$ 65.8	$ 69.4	$ 22.5

Services received from affiliates primarily include shared services provided to TEC from TSI, TECO Energy's centralized services company subsidiary, beginning on January 1, 2015. Through TSI, TECO Energy provided TEC with specialized services at cost, including information technology, procurement, human resources, legal, risk management, financial, and administrative services. TSI's costs are directly charged or allocated to TEC using cost-causative allocation methods. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of total operating revenues, total operating assets and net income as the basis of allocation.

Amounts due from or to affiliates at December 31,

(millions)	*2016*	*2015*
Accounts receivable(1)	$ 6.9	$ 2.3
Accounts payable(1)	18.0	15.9
Taxes receivable(2)	0.0	61.3
Taxes payable(2)	7.2	1.0

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest.

(2) At December 31, 2016, taxes payable were due to EUSHI. At December 31, 2015, taxes receivable were due from TECO Energy. See **Note 4** for additional information.

11. Segment Information

Segments are determined based on how management evaluates, measures and makes decisions with respect to the operations of the entity. Management 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 TEC, but are included in determining reportable segments.

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 approximately 736,000 customers in West Central Florida. Its PGS division is engaged in the purchase, distribution and marketing of natural gas for approximately 374,000 residential, commercial, industrial and electric power generation customers in the State of Florida.

(millions)	Tampa Electric	PGS	Eliminations	TEC
2016				
Revenues - external	$ 1,963.6	$ 432.2	$ 0.0	$ 2,395.8
Sales to affiliates	0.9	7.1	(8.0)	0.0
Total revenues	1,964.5	439.3	(8.0)	2,395.8
Depreciation and amortization	268.4	59.9	0.0	328.3
Total interest charges	91.1	14.7	0.0	105.8
Provision for income taxes	129.8	22.4	0.0	152.2
Net income	250.8	34.9	0.0	285.7
Total assets	7,356.9	1,191.3	(465.6) (2)	8,082.6
Capital expenditures	594.3	132.5	0.0	726.8
2015				
Revenues - external	$ 2,017.7	$ 401.5	$ 0.0	$ 2,419.2
Sales to affiliates	0.6	6.0	(6.6)	0.0
Total revenues	2,018.3	407.5	(6.6)	2,419.2
Depreciation and amortization	256.7	56.8	0.0	313.5
Total interest charges	95.1	14.5	0.0	109.6
Provision for income taxes	143.6	21.9	0.0	165.5
Net income	241.0	35.3	0.0	276.3
Total assets (1)	7,003.8	1,136.1	(431.3) (2)	7,708.6
Capital expenditures	592.6	94.0	0.0	686.6
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 (1)	6,565.4	1,082.8	(373.9) (2)	7,274.3
Capital expenditures	582.1	88.9	0.0	671.0

(1) Certain prior year amounts have been reclassified to conform to current year presentation. These reclassifications relate to deferred tax assets (see note 2 below) and debt issuance costs required by newly issued accounting guidance (see **Note 2**).

(2) Amounts relate to consolidated deferred tax reclassifications. Deferred tax assets are reclassified and netted with deferred tax liabilities upon consolidation.

12. Other Comprehensive Income

TEC reported the following OCI for the years ended December 31, 2016, 2015 and 2014, 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
2016			
Unrealized gain on cash flow hedges	$ 0.0	$ 0.0	$ 0.0
Reclassification from AOCI to net income	1.3	(0.5)	0.8
Gain on cash flow hedges	1.3	(0.5)	0.8
Total other comprehensive income	$ 1.3	$ (0.5)	$ 0.8
2015			
Unrealized gain on cash flow hedges	$ 4.3	$ (1.5)	$ 2.8
Reclassification from AOCI to net income	1.4	(0.7)	0.7
Gain on cash flow hedges	5.7	(2.2)	3.5
Total other comprehensive income	$ 5.7	$ (2.2)	$ 3.5
2014			
Unrealized gain on cash flow hedges	$ 0.0	$ 0.0	$ 0.0
Reclassification from AOCI to net income	1.1	(0.4)	0.7
Gain on cash flow hedges	1.1	(0.4)	0.7
Total other comprehensive income	$ 1.1	$ (0.4)	$ 0.7

Accumulated Other Comprehensive Loss

(millions) As of December 31,	*2016*	*2015*
Net unrealized losses from cash flow hedges (1)	$ (2.8)	$ (3.6)
Total accumulated other comprehensive loss	$ (2.8)	$ (3.6)

(1) Net of tax benefit of $1.8 million and $2.3 million as of December 31, 2016 and 2015, respectively.

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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 customers.

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.

In November 2016, Tampa Electric and the other major electric IOUs in Florida signed a stipulation agreement approved by the FPSC calling for a one-year moratorium on hedging of natural gas purchases. The stipulation agreement calls for the FPSC to oversee one or more workshops beginning in early 2017 to seek a cost-effective way to insure against rising gas prices.

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 December 31, 2016, all of TEC's physical contracts qualify for the NPNS exception.

The derivatives that are designated as cash flow hedges at December 31, 2016 and 2015 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. There were $16.6 million and zero derivative assets as of December 31, 2016 and 2015, respectively. Derivative liabilities totaled zero and $26.2 million as of December 31, 2016 and 2015, respectively. There are minor offset amount differences between the gross derivative assets and liabilities and the net amounts included in the Consolidated Balance Sheets. There was no collateral posted with or received from any counterparties.

All of the derivative asset and liabilities at December 31, 2016 and 2015 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 December 31, 2016, net pretax gains of $15.1 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The December 31, 2016 and 2015 balance in AOCI related to the cash flow hedges and interest rate swaps (unsettled and previously settled) is presented in **Note 12**.

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 December 31, 2016, 2015 and 2014, 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 the years ended December 31, 2016, 2015 and 2014 is presented in **Note 12**. 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 November 30, 2018 for financial natural gas contracts. The following table presents TEC's derivative volumes that, as of December 31, 2016, are expected to settle during the 2017 and 2018 fiscal years:

(millions)	Natural Gas Contracts (MMBTUs)	
Year	Physical	Financial
2017	0.0	26.0
2018	0.0	6.8
Total	0.0	32.8

TEC is exposed to credit risk by 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 December 31, 2016, 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 generally do not require a nonperformance risk adjustment 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.

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 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 December 31, 2016 and 2015. 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.

Recurring Derivative Fair Value Measures

	As of December 31, 2016			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ 0.0	$ 16.6	$ 0.0	$ 16.6

	As of December 31, 2015			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Liabilities				
Natural gas swaps	$ 0.0	$ 26.2	$ 0.0	$ 26.2

Natural gas swaps are OTC swap instruments. The fair value of the swaps is estimated utilizing the market approach. The price of swaps is calculated using observable NYMEX quoted closing prices of exchange-traded futures. These prices are applied to the notional quantities 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 December 31, 2016 and 2015, the fair value of derivatives was not materially affected by nonperformance risk. There were no Level 3 assets or liabilities for the periods presented.

As of December 31, 2016 and 2015, the carrying value of TEC's short-term debt was not materially different from the fair value due to the short-term nature of the instruments and because the stated rates approximate market rates. The fair value of TEC's short-term debt is determined using Level 2 measurements.

See **Notes 5 and 7** for information regarding the fair value of the pension plan investments and long-term debt, respectively.

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.

Tampa Electric 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 250 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 variable interests. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. Tampa Electric 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, and have the obligation or right to absorb losses or benefits. As a result, Tampa Electric is not the primary beneficiary and is not required to consolidate any of these entities. Tampa Electric purchased $62.0 million, $33.6 million and $25.7 million, under these PPAs for the three years ended December 31, 2016, 2015 and 2014, 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. Asset Retirement Obligations

TEC accounts for AROs at fair value at inception of the obligation if there is a legal obligation under applicable law, 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.

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:

	December 31,	
(millions)	*2016*	*2015*
Beginning balance	$ 6.0	$ 5.3
Additional liabilities [(1)]	36.4	0.9
Revisions to estimated cash flows	2.6	(0.5)
Other [(2)]	(0.1)	0.3
Ending balance	$ 44.9	$ 6.0

(1) Tampa Electric produces ash and other by-products, collectively known as CCRs, at its Big Bend and Polk power stations. The increase in the ARO in 2016 is to achieve compliance with the EPA's CCR rule, which contains design and operating standards for CCR management units. In 2016, the FPSC approved Tampa Electric's proposed CCR compliance program for cost recovery through the ECRC. However, additional petitions will be submitted for recovery of future project expense based on engineering studies currently being performed.

(2) Includes accretion recorded as a deferred regulatory asset.

17. Subsequent Event

On February 7, 2017, the FPSC approved a settlement agreement between PGS and OPC agreeing to new depreciation rates that reduce annual depreciation expense, accelerate the amortization of the regulatory asset associated with environmental remediation costs, include obsolete plastic pipe replacements through the existing cast iron and bare steel replacement rider, and decrease the bottom of the ROE range from 9.75% to 9.25%. See **Note 3** for further information on the settlement agreement.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

Item 9A. CONTROLS AND PROCEDURES.

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, December 31, 2016 (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 December 31, 2016 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 December 31, 2016.

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 TEC'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 TEC's internal controls that occurred during TEC's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Item 9B. OTHER INFORMATION.

On February 7, 2017, the FPSC approved a settlement agreement between PGS and OPC agreeing to new depreciation rates that reduce annual depreciation expense, accelerate the amortization of the regulatory asset associated with environmental remediation costs, include obsolete plastic pipe replacements through the existing cast iron and bare steel replacement rider, and decrease the bottom of the ROE range from 9.75% to 9.25%. The new bottom of the range will remain until the earlier of new base rates established in PGS's next general base rate proceeding or December 31, 2020. The top of the range will continue to be 11.75%, and the ROE of 10.75% will continue to be used for the calculation of return on investment for clauses and riders. No change in customer rates resulted from this agreement. See **Note 3** to the **2016 Annual TEC Consolidated Financial Statements** for further information on the settlement agreement.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Executive Officers

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 incorporated herein by reference.

Directors

The three directors listed below were elected by TEC's sole shareholder, TECO Energy, to serve until their successors are elected and qualified.

Name	Age	Director Since	Business Experience
Christopher G. Huskilson (Chairman)	59	July 1, 2016	Mr. Huskilson has served as President and Chief Executive Officer of Emera since 2004. Prior to that, Mr. Huskilson held a number of senior management and leadership positions within Emera's subsidiary, Nova Scotia Power Inc. and its predecessor, Nova Scotia Power Corporation, since joining the company in 1980. Mr. Huskilson's decades of experience and extensive knowledge of the utility and energy industry, mergers and acquisitions, corporate governance, and finance gained through various roles within Emera and Nova Scotia Power Inc., and in the broader electricity industry, regionally, nationally and internationally, as well as other directorships, allow him to provide leadership to TEC, and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEC Board. Mr. Huskilson is also a director of Algonquin Power and Utilities Corp (NYSE:AQN).
Robert R. Bennett	54	July 1, 2016	Mr. Bennett has been Chairman of the Board and Chief Operating Officer of TECO Energy, TEC's parent, since July 1, 2016, and the President and Chief Executive Officer of TECO Energy since September 1, 2016. Mr. Bennett joined Nova Scotia Power Inc. in 1988, and over the course of his nearly 30-year career, he has held senior management and leadership positions across the Emera group. Mr. Bennett served as President and Chief Executive Officer of Emera U.S. Inc. (a wholly-owned subsidiary of Emera) from September 2015 to June 30, 2016, and Executive Vice President and Chief Operating Officer of Emera from January 2013 to September 2015. Prior to that, Mr. Bennett served as President and Chief Executive Officer of Nova Scotia Power Inc. from June 2008 to January 2013. Mr. Bennett's extensive experience in the electric utility business and his positions within the Emera group of companies, including leading the integration of TECO Energy with Emera, have provided him with knowledge of TEC's operations, as well as the utility industry, mergers and acquisitions, and strategic planning, and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEC Board.
Sarah R. MacDonald	48	July 1, 2016	Ms. MacDonald has been President of Emera Caribbean Inc., a subsidiary of Emera, since January 2013, and President of TECO Services, Inc., a subsidiary of TECO Energy, since September 1, 2016. She served as President and Chief Executive Officer of Emera's subsidiary, Grand Bahama Power Company, an integrated utility company supplying electrical power to the island of Grand Bahama, from May 2011 to August 2016. She joined Emera in 2001 and has served as CEO at Emera Utility Services, Executive Vice President of Human Resources for Emera and General

Manager of Human Resources for Nova Scotia Power. Ms. MacDonald's extensive experience in the electric utility business and her senior management and leadership positions within the Emera group of companies, including leading operating and services subsidiaries, have provided her with knowledge of the utility industry and utility operations and services, and such experience contributes to the diverse knowledge, experience, skills and qualifications of the TEC Board.

Board Committees

The Board of Directors does not have separate board committees, therefore the full Board fulfills the Audit Committee duties as identified under Section 3(a)(58)(A) of the Exchange Act. The Board has determined that Mr. Huskilson meets the definition of "audit committee financial expert" under SEC rules.

Code of Ethics

Emera has adopted a code of ethics applicable to all of its employees, officers and directors, including those of its subsidiaries, such as TEC. The text of the *Code of Conduct* is available in the Ethics and Compliance section of the About Us page of TECO Energy's website at www.tecoenergy.com. Any amendments to or waivers of the *Code of Conduct* for the benefit of any executive officer or director will also be posted on the website.

Item 11. EXECUTIVE COMPENSATION.

Compensation Committee Report

The Board of Directors does not have separate board committees, therefore, the full Board fulfills the duties of a Compensation Committee. The Board of Directors has reviewed and discussed the Compensation Discussion & Analysis set forth below with management and, based on this review and discussion, has approved its inclusion in this Annual Report on Form 10-K.

By the Board of Directors:
Christopher G. Huskilson
Robert R. Bennett
Sarah R. MacDonald

Compensation Discussion and Analysis

This Compensation Discussion and Analysis (CD&A) explains how we use different elements of compensation to achieve the goals of our executive compensation program and how we determine the amounts of each component to pay. Our executive compensation program is designed to tie a significant portion of executive pay directly to company performance.

The term “named executive officers” as used throughout this CD&A includes the following current executive officers who are named in the Summary Compensation Table:

- Gordon L. Gillette, President and Chief Executive Officer
- Thomas J. Szelistowski, President, Peoples Gas System
- Gregory W. Blunden, Senior Vice President – Finance and Chief Financial Officer
    - Mr. Blunden is also the Chief Financial Officer of TEC’s ultimate parent, Emera. Therefore, while he is listed as a named executive officer, his compensation is determined and paid by Emera, and the discussion below regarding how compensation was determined does not apply to Mr. Blunden. The amounts shown in this section for Mr. Blunden represent the compensation allocated by Emera to TEC only, which for 2016 amounted to 53% of his total compensation for services provided to TEC since July 1, 2016. The percentage allocated to TEC is obtained using the Modified Massachusetts Formula, an industry-wide accepted method of allocating common costs to affiliated entities based on equal weighting of net income, net assets and total revenues.

The term “named executive officers” also refers to John B. Ramil, former Chief Executive Officer, and Sandra W. Callahan, former Vice President – Finance and Accounting and Chief Financial Officer, who each retired effective September 1, 2016. Mr. Ramil’s and Ms. Callahan’s compensation was determined as described below, unless otherwise noted.

Merger with Emera

As described in **Item 1 – Business**, above, TEC is a wholly owned subsidiary of TECO Energy. On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on September 4, 2015, and TECO Energy became a wholly-owned indirect subsidiary of Emera. Therefore, TEC continues to be a wholly owned subsidiary of TECO Energy and became an indirect wholly owned subsidiary of Emera as of July 1, 2016. Prior to July 1, 2016, the Compensation Committee of the Board of TECO Energy (the Committee) made decisions with respect to TECO Energy’s CEO compensation (who served as both the TECO Energy and Tampa Electric Company CEO prior to his retirement) and equity-based incentives, after consultation with the Board, and the Board made other decisions with respect to executive compensation after considering the recommendations of the Committee. Since July 1, 2016, the Board fulfills the duties of a compensation committee and makes all executive compensation decisions, except for Mr. Gillette, whose compensation is determined by the Emera Board of Directors.

Objectives of our Executive Compensation Program

The objective of TECO Energy’s executive compensation program is to provide competitive compensation to attract and retain the talent needed to successfully manage and build its businesses and to tie a significant portion of executive pay directly to company performance in order to link the interests of our executives to the success of the business.

Total target compensation for 2016 was determined at the beginning of 2016, and was targeted at the 50th percentile of companies of similar size to TECO Energy in its industry (since compensation decisions were determined at the TECO Energy level at that time). The components of the executive compensation program (primarily base salary, short-term incentives and long-term incentives) were designed to keep a significant portion of each named executive officer’s direct compensation variable and earned based upon performance, using a mix of financial goals and individual qualitative goals based on the company’s business plan objectives for that year. Using various performance goals helps ensure that multiple aspects of business success are considered in determining compensation.

How We Make Compensation Decisions

As described above, prior to the July 1, 2016 acquisition of TEC’s parent, TECO Energy, by Emera, TECO Energy’s Compensation Committee was responsible for making recommendations to the Board with respect to executive compensation and approving CEO compensation. In fulfilling these responsibilities during the first half of 2016, the Committee received input from its independent compensation consultant, Steven Hall & Partners (SH&P). SH&P provided research, data analyses, survey information and design expertise to assist the Committee in developing compensation programs for executives. SH&P did not provide any other services to the company in 2016, and SH&P did not receive any fees or compensation from the company other than the customary fees it received as the Committee’s independent compensation consultant. Prior to July 1, 2016, TECO Energy’s management (primarily the CEO and Chief Human Resources Officer) provided the Compensation Committee with information, ideas and input regarding compensation decisions, discussed this information and the recommendations of the Committee’s compensation consultant in detail with the Committee, and answered questions.

Since July 1, 2016, the TEC Board of Directors has made decisions with respect to executive compensation, except for Mr. Gillette, whose compensation is determined by the Emera Board of Directors.

Pay Peer Group

At the beginning of 2016, the Compensation Committee reviewed market data provided by SH&P to help establish executive compensation levels, in order to provide compensation packages competitive with industry peers. This market data included compensation data and pay practices from both the peer group identified below and broader compensation survey data. For 2016, the market data that the Compensation Committee reviewed included publicly disclosed compensation data from a peer group (the Pay Peer Group) which was comprised of publicly-traded electric or electric and gas utility companies with revenues ranging between approximately one-half and two-times TECO Energy's revenues (since pay decisions prior to July 1, 2016 were made at the TECO Energy level, as described above). The companies in the Pay Peer Group for 2016 were as follows:

Alliant Energy Corp.	Integrys Energy Group, Inc.	Pepco Holdings, Inc.	SCANA Corp.
Avista Corporation	NiSource Inc.	Pinnacle West Capital Corp.	Westar Energy, Inc.
Great Plains Energy Inc.	OGE Energy Corp.	Portland General Electric Co.	WEC Energy Group, Inc.
Hawaiian Electric Industries Inc.			

Compensation Review Process

After reviewing market data from its independent compensation consultant and other information described below, management developed 2016 target total compensation recommendations for each named executive officer at the beginning of 2016 (other than for the Mr. Ramil, for whom management did not provide a recommendation), which were then submitted to the Committee for consideration. These recommendations were based on a review and assessment of the following:

- Proxy data from the companies in our Pay Peer Group
- Survey data
- Factors previously identified by the Committee, such as individual performance, time in position, scope of responsibility and experience

Total compensation for each named executive officer was generally targeted at the median of the market data for similar positions, while also taking into consideration the factors noted above.

Components of the 2016 Executive Compensation Program

The table below summarizes the elements of the 2016 executive compensation program, which are described in more detail in the following sections.

Base Salary	Fixed amount of cash compensation targeted at the median of the marketplace in order to provide a competitive amount of fixed annual compensation, designed to attract and retain highly qualified executives.
Annual Incentive Awards	Annual cash incentive based on the achievement of quantitative corporate financial goals (80%) and qualitative individual business plan goals (20%). Intended to encourage actions by the executives that contribute to our operating and financial results and to achieve other goals that the Board has recognized as important for the success of our businesses.
Long-Term Incentive Awards (See the **Long-Term Incentive Awards** section below for a description of the impact of the Merger with respect to these awards)	Restricted stock units: 70% performance units; 30% time-vested units with three year vesting period. At the time of grant the restricted stock units were designed to tie a portion of compensation to long-term performance and aid in retention.
Pension Plan	Tax-qualified defined benefit pension plan available to all of our employees, which aids in attracting and retaining highly qualified employees.
Supplemental Executive Retirement Plan and Pension Restoration Plan	Provides retirement benefits not available under the tax-qualified plan, which further strengthens the retention component of the pension plan.
Change-in-Control Agreements	Provides severance payments if executive is terminated without cause or terminates employment with good reason in connection with a change in control.

Base Salary

At the beginning of 2016, the Compensation Committee considered potential adjustments to executives' base salaries, considering written evaluations of individual performance and responsibilities and the market data described above. This allowed the Committee to consider appropriate variables, such as individual officer's responsibilities and experience levels, and to tailor salaries accordingly, while remaining competitive with the marketplace. Mr. Szelistowski's salary was adjusted based on similar considerations when he was appointed President of Peoples Gas System effective August 31, 2016. Base salary amounts are shown in the **2016 Summary Compensation Table** below.

Annual Incentive Awards

The annual incentive awards paid for 2016 were based on a target award percentage and the level of achievement of the performance goals established for each named executive officer at the beginning of 2016, as described below.

2016 Target Award Levels

Target award amounts under the annual incentive award program were established by reviewing the market data described under *Compensation Review Process* above, and based on the median total compensation for each position, selecting a target award that was designed to provide a competitive total cash opportunity consistent with the total target compensation amount determined for each executive officer.

2016 Performance Metrics, Targets and Results

Financial Goals

Our annual incentive plan provides for financial and/or operational effectiveness goals to be set each year for the plan participants. The Board set threshold, target and maximum goals for the income goals and capital expenditure goals as shown in the table below. The target goals were based on the relevant income and capital expenditure targets contained in Tampa Electric's 2016 business plan. Threshold performance represents the minimum performance that warrants incentive recognition for that particular goal (paid at 50% of the target award level), and maximum performance represents extraordinary performance measured against target (capped at 150% of the target award level for financial goals). These goals are designed to recognize exceptional performance for the year at above the 100% level, while only providing a payout when performance meets or exceeds the threshold.

Below are definitions for each of the goals used for the 2016 Annual Incentive Plan:

- Income Goals: Income from continuing operations before charges and gains.
- Capital Expenditure Goals: This goal focuses on each company's net investment in operating assets for the year and its use of available capital in relation to the Board-approved capital investment plan for that year. It is calculated based on capital

expenditures and disbursements for the year, less allowance for funds used during construction and proceeds from the sale of property and equipment.

- Individual Business Plan Goals: Individual goals for each officer designed to help the company achieve its overall business plan goals.

The 2016 annual incentive goals and financial goal results are shown below.

	2016 Financial Performance Goals (millions)			
Performance Measure	*Relative Weightings %*	*Threshold (50% Payout)*	*Target (100% Payout)*	*Maximum (150% Payout)*
TECO Energy Income Goal	15%	$ 241.7	$ 268.6	$ 280.3
TECO Energy Capital Expenditure Goal	5%	$ (842.5)	($748.6) to ($783.2)	$ (689.3)
Florida Operations Income Goal	45%	$ 264.8	$ 294.2	$ 304.8
Florida Operations Capital Expenditure Goal	15%	$ (756.4)	($670.3) to ($704.9)	$ (618.8)
Individual Business Plan Goals	20%	Goals described below; Level of achievement can range from 0% to 200%		

2016 Financial Goal Results

Performance Measure	*Target (millions)*	*2016 Results(1) (millions)*	*Achievement Percentage*
TECO Energy Income Goal	$ 268.6	$274.9	127%
TECO Energy Capital Expenditure Goal	($748.6) to ($783.6)	($770.4)	100%
Florida Operations Income Goal	$ 294.2	$293.9	99%
Florida Operations Capital Expenditure Goal	($670.3) to ($704.9)	($699.3)	100%

(1) The table below shows how the TECO Energy income goal achievements are reconciled to GAAP net income.

	millions
TECO Energy GAAP Income from Continuing Operations	$195.8
Add Emera transaction-related costs	$63.8
Add Emera transaction – NMPRC settlement	$18.5
Subtract adjustments for incentive purposes	($3.2)
TECO Energy Income Goal Results	$274.9

Individual Goals

Our annual incentive plan also provides for each executive officer to have individual qualitative goals that are designed to help the company achieve its overall business plan goals. Mr. Gillette's goals were developed with Mr. Ramil at the beginning of the year and approved by the Board, and related to leadership of execution of one- and five-year strategic plans to help achieve net income and returns in the plans; growth initiatives; service and quality initiatives; customer relations and communications initiatives; reliability and safety; community relationships; values initiatives; and technology and business process strategies. Mr. Szelistowski's goals were developed prior to his becoming an executive officer and were approved by his supervisor, Mr. Gillette, and related to leadership in achieving financial targets; and leadership of compliance, reliability, customer satisfaction, safety, technology and employee development initiatives. The level of achievement of the individual business plan goals was 150% for Mr. Gillette and 160% for Mr. Szelistowski, which was a qualitative determination made by the Emera Board for Mr. Gillette and the TEC Board for Mr. Szelistowski, after reviewing a performance evaluation of each executive officer. Mr. Ramil and Ms. Callahan received a payment equal to their target incentive awards in connection with their retirements following the Merger.

2016 Annual Incentive Plan Payouts

The 2016 awards to the executive officers under the annual incentive plan were based on the achievement of the corporate financial goals and the individual business plan goals described above. The total amounts awarded under the 2016 annual incentive plan are also shown under the "Non-Equity Incentive Plan Compensation" column in the **2016 Summary Compensation Table**.

Long-Term Incentive Awards

Long-term incentive awards were granted at the beginning of 2016 in the form of Restricted Stock Units (RSUs). Long-term incentive awards were granted at levels that provided each executive officer with total target compensation that was in line with the amounts developed for each officer using the data and process described under **Compensation Review Process** above. At the time of grant, 70% percent of the RSUs were performance-based RSUs and 30% were time-based, however, at the closing of the Merger a portion of the RSUs were paid out (as described below) and the performance conditions were removed from the performance-based RSUs.

Consistent with the terms of the Merger Agreement, shortly after the time of closing of the Merger, a prorated portion of the RSUs was paid out in cash (at the maximum performance measurement, with respect to the performance-based RSUs) based on the per-share merger consideration ($27.55), plus accrued dividends. The prorated portion was based on the amount of time that had elapsed in the three-year vesting schedule between the date of grant and the date of closing (approximately 14%). The remainder of the awards were converted to Cash Service Awards that vest three years from the grant date and will be paid out in cash at vesting, unless employment is terminated during the three-year period without cause by the company or through a normal retirement by the employee (as described below in the **Pension Benefits – Supplemental Plan** section). In those events, a prorated amount of the Cash Service Awards would vest based on the amount of time employed during the remainder of the three-year period. The Cash Service Awards are forfeited if employment is terminated for cause by the company or is terminated by the employee voluntarily (except in the case of a normal retirement).

Retirement and Other Benefits

Supplemental Executive Retirement Plan and Pension Restoration Plan

Mr. Gillette and Mr. Szelistowski participate in a supplemental retirement plan and a pension restoration plan, respectively, that provide benefits at a level not available under the tax-qualified plan and are meant as an additional aid in attracting and retaining officers in key positions.

Change-in-Control Agreements

Messrs. Gillette and Szelistowski have change-in-control severance agreements with TECO Energy. These agreements are "double-trigger" arrangements, meaning that payments are only made if there is a change in control of the company or one is being contemplated and the officer's employment is terminated without cause or the officer terminates employment for good reason. A change in control occurred upon the closing of the Merger. The agreements, and the change-in-control agreements with our former executive officers, Mr. Ramil and Ms. Callahan, are discussed in greater detail under the **Post-Termination Benefits** section. We believe that providing these agreements helps increase our ability to attract, retain and motivate highly qualified management personnel and encourage their continued dedication without distraction from concerns over job security relating to a change in control of the company.

Tax Considerations

While the Committee and Board consider the tax implications of their compensation decisions, such as maintaining the deductibility of compensation for the company, their primary objective in making compensation decisions was to provide compensation that best meets the goals of the compensation program. Therefore, while the tax impact of any compensation arrangement was one factor to be considered, this impact was evaluated in light of the objectives of the compensation program described above.

The following tables give information regarding the compensation provided to our named executive officers.

2016 Summary Compensation Table

Name and Principal Position	*Year*	*Salary ($)*	*Stock Awards[1] ($)*	*Non-Equity Incentive Plan Compensation ($)*	*Change in Pension Value and Nonqualified Deferred Compensation Earnings [2] ($)*	*All Other Compensation [3]($)*	*Total ($)*
Gordon L. Gillette	2016	562,380	812,300	448,031	1,283,553	11,214	3,117,478
President and Chief Executive Officer	2015	546,000	541,322	412,600	299,759	11,919	1,811,600
	2014	546,000	651,595	382,200	665,850	12,948	2,258,593
Gregory W. Blunden [4]	2016	79,005	71,004	47,403	n/a	29,626	227,038
Senior Vice President – Finance and Accounting and Chief Financial Officer							
Thomas J. Szelistowski [5]	2016	262,852	129,966	180,498	259,180	136,214	968,710
President, Peoples Gas System							
John B. Ramil [6]	2016	757,020	2,978,386	880,650	3,456,452	15,055,372 [7]	23,127,880
former Chief Executive Officer	2015	855,000	2,977,258	1,068,750	1,626,432	11,919	6,539,359
	2014	785,000	2,345,728	867,456	1,327,441	12,948	5,338,573
Sandra W. Callahan [6]	2016	373,218	768,940	351,037	685,316	2,637,554 [8]	4,816,065
former Senior Vice President – Finance	2015	489,250	768,665	393,846	1,042,411	11,919	2,706,091
and Accounting and Chief Financial Officer	2014	475,000	586,435	367,426	740,164	12,948	2,181,973

(1) The amounts reported for stock awards reflect the aggregate grant date fair value of the restricted stock units granted in 2016 based on the "target awards," computed in accordance with FASB Accounting Standards Codification (ASC) Topic 718. As noted under "**Long-Term Incentives**" above, in accordance with the Merger Agreement, all equity awards granted prior to 2016 were paid out in connection with the Merger, and 14% of the restricted stock unit awards granted in 2016 were paid out in connection with the Merger (with the remainder converted to a cash service award to be paid out three years following the grant date to continuing employees).

(2) This column shows the change in the actuarial present value of the benefits that would be provided under our tax-qualified defined benefit plan and our supplemental retirement plan or restoration plan, if applicable. This value is calculated based on variables such as average earnings and years of service, and therefore a larger increase in value may be attributable, for example, to an increase in pay, year over year. Other factors affecting the present value include interest rates and the age of the officer. See **Pension Benefits** below for a description of our retirement plans. The changes in value shown above are attributable to both plans, with the change in value attributed only to the tax-qualified plan in: 2016, 2015 and 2014, respectively, of $147,231, $20,047 and $159,168 for Mr. Gillette; $310,310, $54,656 and $195,427 for Mr. Ramil; $217,690, $105,718 and $211,904 for Ms. Callahan; and $153,718 for Mr. Szelistowski in 2016. The balance in each case represents the change in value of the supplemental plan or restoration plan, as applicable. Mr. Blunden is not a participant in these plans. TEC does not maintain a non-qualified deferred compensation plan for employees.

(3) The amounts reported in this column for 2016 include for each named executive officer other than Mr. Blunden include $84 in premiums for supplemental life insurance ($56 for Mr. Ramil and Ms. Callahan) and $11,130 of employer contributions under the TECO Energy Group Retirement Savings Plan. The amount reported for Mr. Blunden is the other compensation allocated to TEC for benefits other than salary and incentive compensation.

(4) Mr. Blunden was appointed Senior Vice President – Finance and Chief Financial Officer effective August 31, 2016. He was not a TEC officer or employee prior to that time. Mr. Blunden is also the Chief Financial Officer of TEC's ultimate parent, Emera. Amounts shown for Mr. Blunden represent only the amounts allocated by Emera for services to TEC and do not include amounts paid by Emera for services to others. For 2016 services, 53% of the amounts paid by Emera were allocated for services to TEC since July 1, 2016.

(5) Mr. Szelistowski was appointed President of Peoples Gas System effective August 31, 2016. Prior to that he was Vice President – Gas Delivery. He was not an executive officer before 2016. All Other Compensation for Mr. Szelistowski included a $125,000 transaction bonus paid in accordance with the Merger Agreement.

(6) Mr. Ramil and Ms. Callahan retired effective September 1, 2016. Mr. Ramil and Ms. Callahan were also officers of TECO Energy. The amounts shown for them are the total compensation amounts paid by TECO Energy, not the portion allocated to TEC.

(7) All Other Compensation for Mr. Ramil included the payments as described under footnote 3 above, payment for accrued vacation time of $83,408, social club dues of $5,825, spousal travel benefit of $2,678, and as described under **Agreements with**

Former Executive Officers under "Post-Termination Benefits" below, cash severance of $5,328,100 and excise tax gross-up of $9,624,175.

(8) All Other Compensation for Ms. Callahan included the payments as described under footnote 3 above, payment for accrued vacation time of $46,291, social club dues of $1,130 and, as described under **Agreements with Former Executive Officers** under "Post-Termination Benefits" below, cash severance of $2,578,947.

Grants of Plan-Based Awards for the 2016 Fiscal Year

		Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1),(2)			*Estimated Future Payouts Under Equity Incentive Plan Awards (3) (performance shares)*			*All Other Stock Awards: Number of Shares of Stock or Units (4)*	*Grant Date Fair Value of Stock and Option Awards (5)*
Name/Award Type	*Grant Date*	*Threshold ($)*	*Target ($)*	*Maximum ($)*	*Threshold (#)*	*Target (#)*	*Maximum (#)*	*(#)*	*($)*
Gordon L. Gillette									
Annual incentive plan	2/3/16	196,833	393,666	590,499					
Performance units	2/3/16				4,806	19,224	38,448		587,293
Time-vested restricted stock units	2/3/16							8,239	225,007
Thomas J. Szelistowski									
Annual incentive plan	2/3/16	78,375	156,750	235,125					
Performance units	2/3/16				769	3,076	6,152		93,972
Time-vested restricted stock units	2/3/16							1.318	35,995
John B. Ramil									
Annual incentive plan	2/3/16	440,325	880,650	1,320,975					
Performance units	2/3/16				17,622	70,487	140,974		2,153,378
Time-vested restricted stock units	2/3/16							30,209	825,008
Sandra W. Callahan									
Annual incentive plan	2/3/16	175,518	351,037	526,555					
Performance units	2/3/16				4,550	18,198	36,396		555,949
Time-vested restricted stock units	2/3/16							7,799	212,991

(1) The amount that was received in 2016 under the annual incentive plan is reported for each officer in the "Non-Equity Incentive Plan Compensation" column of the **2016 Summary Compensation Table**.

(2) See the description in the **CD&A** section above regarding how the threshold, target and maximum awards were determined.

(3) Amounts in these columns represent performance unit grants. In accordance with the Merger Agreement, a prorated portion of the maximum number of units were paid out at the merger consideration price of $27.55 at closing and the remainder was converted to a cash service award which vests December 31, 2018.

(4) Amounts in this column represent time-vested restricted stock unit grants made under TECO Energy's 2010 Equity Incentive Plan. In accordance with the Merger Agreement, a prorated portion of the units were paid out at the merger consideration price of $27.55 at closing and the remainder was converted to a cash service award which vests February 3, 2019.

(5) Amounts in this column are based on the grant date fair value in accordance with FASB ASC Topic 718.

The amounts payable under the annual incentive plan are determined based on the achievement of certain corporate financial and individual qualitative goals described in the **CD&A** section above. The threshold, target and maximum amounts that could have been paid under the 2016 annual incentive plan are shown in the table above in the "Estimated Possible Payout Under Non-Equity Incentive Plan Awards."

Information regarding the restricted stock units is included in the **CD&A** section above under "Long-Term Incentive Awards."

Outstanding Equity Awards at 2016 Fiscal Year-End

As a result of the Merger, all outstanding equity awards were paid out in accordance with Merger Agreement upon closing and there were no outstanding equity awards at 2016 fiscal year-end.

Option Exercises and Stock Vested in the 2016 Fiscal Year

	Option Awards		*Stock Awards*	
Name	*Number of Shares Acquired on Exercise (#)*	*Value Realized on Exercise ($)*	*Number of Shares Acquired on Vesting [1] (#)*	*Value Realized on Vesting [2] ($)*
Gordon L. Gillette	--	--	151,660	4,141,098
Thomas J. Szelistowski	--	--	11,788	322,942
John B. Ramil	--	--	642,417	17,583,999
Sandra W. Callahan	--	--	157,597	4,315,262

(1) Includes outstanding equity awards that vested upon closing of the Merger in accordance with the Merger Agreement.
(2) The awards vested at the merger consideration price of $27.55.

Pension Benefits

The following table shows the present values of accumulated benefits payable under the pension plan arrangements for the named executive officers as of December 31, 2016, the most recent pension plan measurement date for financial reporting purposes. The “qualified plan” refers to the TECO Energy Group Retirement Plan, our tax-qualified defined benefit plan that is available to our U.S. employees; the “supplemental plan” refers to the TECO Energy Group Supplemental Executive Retirement Plan; and the “restoration plan” refers to the TECO Energy Group Restoration Benefit Plan, each as described below. Mr. Blunden is not a participant in these plans and is a participant of the Emera corporate pension plan. Approximately 6% of the compensation expense allocated to TEC for Mr. Blunden’s services related to retirement benefits.

Name	*Plan Name*	*Number of Years Credited Service [1] (#)*	*Present Value of Accumulated Benefit ($)*	*Payments During Last Fiscal Year ($)*
Gordon L. Gillette	qualified plan	36	845,409	—
	supplemental plan		5,386,583	
Thomas J. Szelistowski	qualified plan	38	803,358	—
	restoration plan		105,462	
John B. Ramil	qualified plan	40	1,373,157	28,621
	supplemental plan		10,371,843	0
Sandra W. Callahan	qualified plan	28	1,483,656	32,910
	supplemental plan		5,183,992	0

(1) The number of years of credited service is the same for the plans and is rounded to the nearest whole year.

Qualified Plan

Our employees are eligible to participate in TECO Energy’s tax-qualified defined benefit plan, and become 100% vested in the benefit they have accrued upon completion of three years of service or reaching the age of 65. All of our named executive officers (except for Mr. Blunden, who is an Emera employee) are vested in this plan. Normal retirement age for the qualified plan is the same as the eligibility age for unreduced Social Security benefits. Under the terms of the qualified plan applicable to the named executive officers, the earliest age at which retirement benefits are available without reduction for age is three years before the normal retirement age.

The qualified plan’s normal retirement payment and benefit formula is based on the employee’s age, years of service and final average earnings. Benefits can be paid as an annuity or in a lump sum, at the election of the participant.

The present value of the accumulated benefit under the qualified plan in the table above was calculated assuming that participants retire at the earliest age at which retirement benefits are available without reduction for age, using the same assumptions TEC used for pension plan measurement for 2016 financial statement reporting purposes with respect to the present value discount rate (4.16%), lump sum conversion rate (4.0%), and form of payment and mortality assumptions.

Supplemental Plan

The normal retirement payment and benefit formula for the named executive officers who are participants in the supplemental plan is 3% times final average earnings times years of credited service, up to a maximum of 20 years (therefore, the maximum amount payable is 60% of final average earnings). Final average earnings are based on the greater of (a) the officer’s final 36 months of earnings or (b) the officer’s highest three consecutive calendar years of earnings out of the five calendar years preceding retirement.

The earnings covered by the qualified plan and supplemental plan are the same as those reported as salary and non-equity incentive plan awards in the summary compensation table above. The pension benefits are computed as a straight-life annuity commencing at the officer's normal retirement age and are reduced by the officer's Social Security benefits. Benefits payable under the supplemental plan are also reduced by benefits payable under the qualified pension plan. Normal retirement age is 64 for Mr. Gillette. A reduced amount of benefits may be received upon retirement any time after age 55, as long as the officer has five years of service. If early retirement is elected, payment is based on actual years of service at early retirement using the formula described above, however, benefits are reduced by 5% for each year that payment begins before the normal retirement date.

The benefit payable under the supplemental plan is paid in the form of a lump sum only (not an annuity). The present value of the accumulated benefit for the supplemental plan shown in the table above was calculated by discounting the lump sum that would be payable at the officer's normal retirement age using a discount rate of 3.37%.

If the officer dies during employment before reaching normal retirement age, the officer's benefits under the supplemental and qualified plan are payable to the surviving spouse in a reduced amount. This death benefit is equal to 50% of the benefit that would have been payable to the officer based on the officer's service as if employment had continued until retirement age. The supplemental plan death benefit is payable in the form of a lump sum to the spouse minus benefits payable to the spouse under the qualified plan.

Restoration Plan

Mr. Szelistowski is a participant in TECO Energy's pension restoration plan, which is a non-qualified plan for certain eligible employees who are not participants in the supplemental executive retirement plan that provides a retirement plan benefit for the portion of their income that exceeds IRS limits for tax-qualified plans. The restoration plan follows the same plan design as the qualified plan described above, except that there is no limit on pensionable earnings applied to the benefit formula. The benefit payable under the restoration plan is paid in the form of a lump sum based on the incremental benefit above what the qualified plan provides. The present value of the accumulated benefit for the supplemental plan shown in the table above was calculated by discounting the lump sum that would be payable at the officer's normal retirement age using a discount rate of 3.64%.

Post-Termination Benefits

Change-in-Control Agreements with Messrs. Gillette and Szelistowski

TECO Energy has change-in-control severance agreements with Messrs. Gillette and Szelistowski under which payments would be made under certain circumstances in connection with a change in control of TECO Energy. A change in control means in general an acquisition by any person of 30% or more of our common stock, a change in a majority of our directors, a merger or consolidation in which our shareholders have less than 50% of the voting power in the surviving entity, or a liquidation or sale of substantially all of our assets. A change in control occurred upon the closing of the Merger and the agreements described below continue for a period of three years following such closing for Mr. Gillette and two years for Mr. Szelistowski.

The change-in-control agreements are "double-trigger" arrangements that only provide for payment of the benefits described below if there is a change in control or one is contemplated and

- employment is terminated without cause (as defined below) or
- employment is terminated by the officer for good reason (as defined below).

If employment is terminated under those circumstances, after expiration of a six-month deferral period as may be required under Section 409A of the Internal Revenue Code, we will make or provide:

- a lump sum severance payment to Mr. Gillette of three times his annual salary and highest target annual incentive award in effect at any time during the thirty-six months prior to the date of termination, and a lump sum severance payment to Mr. Szelistowski of two times his annual salary and highest target annual incentive award in effect at any time during the twenty-four months prior to the date of termination,
- a cash payment equal to the actuarial equivalent of the additional retirement benefit that would have been earned under our retirement plans if employment had continued for three years following the date of termination for Mr. Gillette and two years for Mr. Szelistowski,
- company-paid life, disability, accident and health insurance plans for a three-year period for Mr. Gillette and a two-year period for Mr. Szelistowski, except to the extent these benefits are provided by a subsequent employer, and
- for Mr. Gillette (whose change-in-control severance agreement was put in place before 2010), a payment in compensation for any additional taxes that may be payable as a result the 20% excise tax imposed under Section 4999 of the Internal Revenue Code on the benefits received under the change-in-control severance agreements and any other benefits contingent on a change in control; however, such payment will only be made if the total payment due in connection with a change-in-control exceeds the amount at which an excise tax is first imposed by at least 10%. If the total payment due does not exceed by at least 10% the amount at which an excise tax is first imposed, the total payment will be reduced to the point that an excise tax would not be imposed. In 2010, the Compensation Committee determined not to provide excise tax gross-ups in change-in-control agreements going forward. Mr. Szelistowski's change-in-control agreement does not provide for an excise tax-gross

up, but rather provides that benefits will be capped at the level at which an excise tax under Section 4999 of the Internal Revenue Code would not be imposed.

For the purposes of the change-in-control agreements, termination with "cause" is defined as termination resulting from the willful and continued failure to substantially perform job duties or willful engagement in conduct which is demonstrably and materially injurious to the company, monetarily or otherwise. Termination of employment for "good reason" is defined as termination by the officer following the assignment to the officer of any duties inconsistent (except in the nature of a promotion) with the position held immediately prior to the change in control or a substantial adverse alteration in the nature or status, responsibilities or the conditions of employment, a reduction in annual base salary, the company's requiring the officer to be based more than 50 miles from current job location, the failure by the company to pay compensation within seven days of the due date, the discontinuation without substitution of any material compensation or benefit plan or other benefits the officer participated in immediately prior to the change in control or reduction of those benefits, or the company's attempt to terminate the officer's employment in a manner not consistent with the terms of the agreement.

Under the terms of the change-in-control agreements, in the event employment is terminated as described above, the officer would be entitled to receive his base salary through the termination date.

Other benefits may also be paid under the supplemental executive retirement plan (as described above under **Pension Benefits**).

Emera Employment Contract with Mr. Blunden

Mr. Blunden has an employment contract with Emera that provides for certain payments if his employment with Emera is terminated without cause or in connection with a change in control of Emera. There are no separate agreements related to his position with TEC. If his employment with Emera is terminated without cause, he is entitled to a lump sum payment equal to 12 months' compensation based upon annual salary and short-term incentive at target. Health, dental and other such benefits will be continued for up to 12 months. Unvested Emera performance share units are prorated to the date of termination and paid out assuming a performance factor of 1.0 and using the average closing share price for Emera common shares for the 50 trading days immediately preceding the termination date. Unvested Emera stock options are forfeited. If there is a change of control of the ownership of Emera, such that any one party acquires 50% or more of voting securities and there is a substantial reduction in responsibilities or scope of authority, Mr. Blunden may elect, within three months following such substantial reduction in responsibilities or scope of authority, to terminate employment and receive 12 months' compensation based upon annual salary and short-term incentive at target. Health, dental and other such benefits will be continued for up to 12 months. Unvested Emera performance share units are prorated to the date of termination and paid out assuming a performance factor of 1.0 and using the average closing share price for Emera common shares for the 50 trading days immediately preceding the termination date. Unvested Emera stock options are forfeited.

Post-Termination Benefits Table

The table below shows the amounts that would be payable to Messrs. Gillette and Szelistowski in connection with a termination without cause or for good reason in contemplation of or following a change of control. There are no agreements or arrangements with these officers for any termination scenarios not involving a change in control. The amounts shown for Mr. Blunden are the total amounts (not the amount that would be allocated to TEC) that would be payable in connection with termination without cause or a change in control of Emera, as described above.

The amounts below are calculated as if such event had occurred on December 31, 2016. Other assumptions that were made in order to calculate these amounts are that no accrued base salary or prorated incentive payment was owed on that date.

The change-in-control agreements provide enhancements to the benefit formula of the retirement plans, as described above, and the retirement-related benefits shown below are the incremental amounts representing the enhanced benefit. The tax-qualified defined benefit plan, supplemental executive retirement plan and restoration plan are described in more detail under **Pension Benefits** above, and the present value of accumulated benefits under our pension arrangements are shown in that section. Any value of such arrangements that is not directly attributable to the change in control is not included in this section.

Health care benefits are based on the continuation of benefits for three years at the officer's current level of coverage.

Under the terms of our change-in-control agreements, as described in more detail above, under certain circumstances Mr. Gillette would be eligible to receive an excise tax gross-up payment if additional taxes are due by him as a result of the application of the excise tax associated with Section 280G of the Internal Revenue Code. The amounts shown below are pre-tax; the officer would be responsible for paying income, excise, and any other applicable taxes on the amounts received.

Name	*Cash Severance ($)*	*Accelerated LTI Vesting ($)*	*Health Care Benefits ($)*	*Retirement-Related Benefits ($)*	*Excise Tax Gross-Up ($)*	*Total ($)*
Gordon L. Gillette	2,892,130	1,089,801	54,467	152,881	2,942,725	7,132,004
Gregory W. Blunden[(1)]	477,612	130,934	3,964	--	--	612,510
Thomas J. Szelistowski	--[(2)]	6,579 [(2)]	11,713	466,993	--	485,285

(1) Amounts for Mr. Blunden have been converted from Canadian to U.S. dollars using the conversion rate on December 31, 2016 of $1.34.

(2) These amounts were reduced to the level at which an excise tax under Section 4999 of the Internal Revenue Code would not be imposed, pursuant to the terms of Mr. Szelistowski's change in control agreement.

Agreements with Former Executive Officers

Our former CEO and CFO, Mr. Ramil and Ms. Callahan, respectively, had change-in-control severance agreements with TECO Energy consistent with the terms of the agreement with Mr. Gillette described above. Because Ms. Callahan's agreement was entered into after 2010, her agreement did not contain an excise tax gross-up, but rather provided for benefits to be capped in those instances in which applying such cap would provide greater after-tax benefits after the application of Section 4999 of the Internal Revenue Code. The change-in-control agreements provide enhancements to the benefit formula of the retirement plans, as described above, and the retirement-related benefits shown below are the incremental amounts representing the enhanced benefit, if any. The amounts shown below are actual amounts paid or accrued in connection with the termination of their employment following the change in control of TECO Energy.

Name	*Cash Severance ($)*	*Accelerated Equity Vesting ($)*	*Health Care Benefits ($)*	*Retirement-Related Benefits ($)*	*Excise Tax Gross-Up ($)*	*Total ($)*
John B. Ramil	5,328,100	17,521,893	15,755	25,010	9,624,175	32,514,933
Sandra W. Callahan	2,578,947	4,443,511	9,383	--	--	7,031,841

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

All of the outstanding shares of common stock, no par value, of TEC are held by TECO Energy, which is an indirect, wholly-owned subsidiary of Emera.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Certain Relationships and Related Person Transactions

Our Board has adopted a written policy regarding the review, approval or ratification of related person transactions. A related person transaction for the purposes of the policy is a transaction between the company and one of our directors, executive officers or 5% shareholders, or a member of one of these person's immediate family, in which such person has a direct or indirect material interest and involves more than $120,000. Under this policy, related person transactions are prohibited unless the Board has determined in advance that the transaction is fair and reasonable to the company. The policy contains procedures that require the Board receive the following information regarding the transaction and consider the following factors before deciding whether to approve a proposed transaction:

- information regarding the parties involved in the transaction and their relationship to the company,
- a complete description of the material terms of the transaction, including economic and non-economic features,
- the direct and indirect interests present in the proposed transaction,
- the relationships present in the proposed transaction, and
- the conflicts or potential conflicts present in the proposed transaction.

After receiving such information and considering the above factors, the policy calls for the Board to determine, in its judgment, whether the transaction is fair and reasonable to the company, and whether or not such transaction should be approved on such basis. In the event the company enters into such a transaction without Board approval, the Board must promptly review its terms and may ratify the transaction if it determines it is fair and reasonable to the company and any failure to comply with the pre-approval policy was not due to fraud or deceit. In 2016, there were no related person transactions as defined above.

Director Independence

TEC's directors are not independent since they are executive officers of Emera or its affiliates. There are no standing committees of the Board of Directors of TEC.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

Fees Paid by TEC to the Independent Auditor

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers LLP for the audit of TEC's annual financial statements for the years ended December 31, 2016 and 2015, and fees billed for other services rendered by PricewaterhouseCoopers LLP during these periods.

	2016	2015
Audit fees	$ 997,380	$ 1,120,027
Audit-related fees	156,890	395,682
Tax fees		
Tax compliance fees	0	0
Tax planning fees	23,750	0
All other fees	0	0
Total	$ 1,178,020	$ 1,515,709

Audit fees consist of fees for professional services performed for (i) the audit of our annual financial statements (ii) the related reviews of the financial statements included in our 10-Q filings, (iii) services that are normally provided in connection with statutory and regulatory filings or engagements and (iv) subsidiary stand-alone financial statements.

Audit-related fees consist of fees for professional services that are reasonably related to the performance of the audit or review of our financial statements, such as required activities related to debt offerings.

Tax fees consist of tax compliance fees for tax return review and income tax provision review, and tax planning fees, including tax audit advice.

All other fees, if any, consist of fees for other work performed by PricewaterhouseCoopers LLP, including fees for assessments and recommendations related to specific transactions, regulatory accounting advice and other miscellaneous services.

Audit Committee Pre-Approval Policy

Prior to July 1, 2016, all services performed by the independent auditor were approved by the TECO Energy Audit Committee pursuant to its policy for pre-approval of services to be provided by our independent auditor. Under the policy, the Audit Committee pre-approved the annual audit engagement terms and fees and the specific types of services to be performed by the independent auditor throughout the year, based on the Audit Committee's determination that the provision of the services would not be likely to impair the auditor's independence. The pre-approval was effective for the current fiscal year and until the Audit Committee met to re-approve services for the following year, or such other period as the Committee may have designated. The policy permitted the Audit Committee to delegate pre-approval authority to one or more of its members to ensure prompt handling of unexpected matters, with such delegated pre-approvals to be reported to the Audit Committee at its next meeting. The policy also contained a list of prohibited non-audit services and required that the independent auditor ensure that all audit and non-audit services provided to us have been pre-approved by the Audit Committee.

After July 1, 2016, all services performed by the independent auditor are approved by the Board in accordance with Emera's pre-approval policy for services provided by the independent auditor.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) **Certain Documents Filed as Part of this Form 10-K**

1. Financial Statements
   Tampa Electric Company Financial Statements
      Report of Independent Registered Public Accounting Firm dated February 10, 2017 of PricewaterhouseCoopers LLP
      Consolidated Balance Sheets at December 31, 2016 and 2015
      Consolidated Statements of Income and Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014
      Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014
      Consolidated Statements of Retained Earnings for the Years Ended December 31, 2016, 2015 and 2014
      Consolidated Statements of Capitalization for the Years Ended December 31, 2016, 2015 and 2014
      Notes to Consolidated Financial Statements
2. Financial Statement Schedules
   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.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TAMPA ELECTRIC COMPANY
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended December 31, 2016, 2015 and 2014
(millions)

	Balance at Beginning of Period	Additions		Payments & Deductions [1]	Balance at End of Period
		Charged to Income	Other Charges		
Allowance for Uncollectible Accounts:					
2016	$ 1.5	$ 2.7	$ 0.0	$ 3.0	$ 1.2
2015	$ 1.4	$ 2.7	$ 0.0	$ 2.6	$ 1.5
2014	$ 2.0	$ 2.7	$ 0.0	$ 3.3	$ 1.4

(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.

TAMPA ELECTRIC COMPANY

Dated: February 10, 2017

By: /s/ Gordon L. Gillette
Gordon L. Gillette
President and Chief Executive Officer
(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 10, 2017:

	Title
/s/ Gordon L. Gillette Gordon L. Gillette	President and Chief Executive Officer (Principal Executive Officer)
/s/ Gregory W. Blunden Gregory W. Blunden	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer) (Principal Financial and Accounting Officer)

Signature	Title		
/s/ Robert R. Bennett Robert R. Bennett	Director	/s/ Christopher G. Huskilson Christopher G. Huskilson	Chairman of the Board and Director
/s/ Sarah R. MacDonald Sarah R. MacDonald	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	
3.1	Restated Articles of Incorporation of Tampa Electric Company, as amended on November 30, 1982 (Exhibit 3 to Registration Statement No. 2-70653 of Tampa Electric Company).	*
3.2	Bylaws of Tampa Electric Company, as amended effective February 2, 2011 (Exhibit 3.4, Form 10-K for 2010 of 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 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 March 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 March 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 November 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 January 5, 2006 (including the form of bond) (Exhibit 4.1, Form 8-K dated January 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).	*
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	Note Purchase Agreement among Tampa Electric Company and the Purchasers party thereto, dated as of April 11, 2003 (Exhibit 10.1, Form 8-K dated April 14, 2003 of Tampa Electric Company).	*
4.10	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).	*
4.11	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).	*
4.12	Eighth Supplemental Indenture dated as of November 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 December 9, 2010 of Tampa Electric Company).	*
4.13	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).	*
4.14	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).	*
4.15	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).	*
		*

Exhibit No.	Description	
4.16	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 August 1, 1946 (Exhibit 4.30, Form 10-K for 2013 of Tampa Electric Company).	
4.17	Twelfth Supplemental Indenture dated as of May 20, 2015, 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 4.20% Notes due 2045) (Exhibit 4.24, Form 8-K dated May 20, 2015 of Tampa Electric Company).	*
10.1	TECO Energy Group Supplemental Executive Retirement Plan, as amended and restated as of November 1, 2007 (Exhibit 10.1, Form 10-K for 2007 of Tampa Electric Company).	*
10.2	TECO Energy Group Supplemental Disability Income Plan, dated as of March 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 November 17, 2008 (Exhibit 10.3, Form 10-K for 2008 of Tampa Electric Company).	*
10.4	TECO Energy Group Benefit Restoration Plan dated as of November 13, 2015 (Exhibit 10.4, Form 10-K for 2015 of Tampa Electric Company).	*
10.5	Annual Incentive Compensation Plan for TECO Energy and subsidiaries, revised as of February 2, 2011 (Exhibit 10.4, Form 10-K for 2011 of Tampa Electric Company).	*
10.6	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 September 30, 2008 of Tampa Electric Company).	*
10.7	Form of Change-in-Control Severance Agreement between TECO Energy, Inc. and certain Executive Officers (Exhibit 10.1, Form 8-K dated February 5, 2010 of TECO Energy, Inc.).	*
10.8	Insurance Agreement dated as of January 5, 2006 between Tampa Electric Company and Ambac Assurance Corporation (Exhibit 10.1, Form 8-K dated January 19, 2006 of Tampa Electric Company).	*
10.9	Third Amended and Restated Credit Agreement dated as of October 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 October 25, 2011 of Tampa Electric Company).	*
10.10	Amended and Restated Purchase and Contribution Agreement dated as of March 24, 2015, between Tampa Electric Company, as the Originator, and TEC Receivables Corp., as the Purchaser (Exhibit 10.1, Form 8-K dated March 24, 2015 of TECO Energy, Inc.).	*
10.11	Loan and Servicing Agreement dated as of March 24, 2015, among TEC Receivables Corp., as Borrower, Tampa Electric Company, as Servicer, certain lenders named therein, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as Program Agent (Exhibit 10.2, Form 8-K dated March 24, 2015 of TECO Energy, Inc.).	*
10.12	Amendment No. 1 to Loan and Servicing Agreement dated as of August 10, 2016, among TEC Receivables Corp., as Borrower, Tampa Electric Company, as Servicer, certain lenders named therein, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as Program Agent (Exhibit 10.1, Form 10-Q for the quarter ended September 30, 2016 of Tampa Electric Company).	*
10.13	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 December 17, 2013 of Tampa Electric Company).	*
10.14	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 September 30, 2014 of Tampa Electric Company).	*
10.15	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 September 30, 2014 of Tampa Electric Company).	*
12	Ratio of Earnings to Fixed Charges.	

Exhibit No.	Description
21	Subsidiaries of Tampa Electric Company.
23	Consent of Independent Certified Public Accountants.
31.1	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.
31.2	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	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)
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 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 10.7, above are management contracts or compensatory plans or arrangements in which executive officers or directors of Tampa Electric Company participate.

Exhibit 12

TAMPA ELECTRIC COMPANY
RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth Tampa Electric Company's ratio of earnings to fixed charges for the periods indicated.

	Year Ended Dec. 31,				
(millions)	2016	2015	2014	2013	2012
Income from continuing operations, before income taxes	$ 437.9	$ 441.8	$ 416.2	$ 364.4	$ 368.9
Interest expense	119.8	122.1	115.8	112.7	129.9
Earnings before taxes and fixed charges	$ 557.7	$ 563.9	$ 532.0	$ 477.1	$ 498.8
Interest expense	$ 119.8	$ 122.1	$ 115.8	$ 112.7	$ 129.9
Total fixed charges	$ 119.8	$ 122.1	$ 115.8	$ 112.7	$ 129.9
Ratio of earnings to fixed charges	4.66x	4.62x	4.59x	4.23x	3.84x

For the purposes of calculating these ratios, earnings consist of income from continuing operations before income taxes and fixed charges. Fixed charges consist of interest expense on indebtedness, amortization of debt premium and an estimate of the interest component of rentals. Interest expense includes total interest expense, excluding AFUDC, and an estimate of the interest component of rentals.

Exhibit 21

SUBSIDIARIES OF TAMPA ELECTRIC COMPANY

The following is a list of subsidiaries (greater than 50% owned) of Tampa Electric Company and their respective states or other jurisdictions of incorporation or organization.

Subsidiary Name	State or Other Jurisdiction of Incorporation or Organization
SLA 75, LLC	Florida
TECO Partners, Inc.	Florida
TEC Receivables Corp.	Delaware

Exhibit 23

CONSENT OF INDEPENDENT REGISTERED CERTIFIED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-202565-01) of Tampa Electric Company of our report dated February 10, 2017 relating to the financial statements and the financial statement schedule which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida
February 10, 2017

Exhibit 31.1

CERTIFICATIONS

I, Gordon L. Gillette, certify that:

1. I have reviewed this annual report on Form 10-K of Tampa Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2017

/s/ GORDON L. GILLETTE
GORDON L. GILLETTE
President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, Gregory W. Blunden, certify that:

1. I have reviewed this annual report on Form 10-K of Tampa Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 10, 2017

/s/ GREGORY W. BLUNDEN
GREGORY W. BLUNDEN
Senior Vice President-Finance and Accounting and
Chief Financial Officer
(Chief Accounting Officer)
(Principal Financial and Accounting Officer)

Exhibit 32

TAMPA ELECTRIC COMPANY

Certification of Periodic Financial Report
Pursuant to 18 U.S.C. Section 1350

Each of the undersigned officers of Tampa Electric Company (the "Company") certifies, under the standards set forth in and solely for the purposes of 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his or her knowledge, the Annual Report on Form 10-K of the Company for the year ended December 31, 2016 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and information contained in that Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: February 10, 2017

/s/ GORDON L. GILLETTE
GORDON L. GILLETTE
President and Chief Executive Officer
(Principal Executive Officer)

Dated: February 10, 2017

/s/ GREGORY W. BLUNDEN
GREGORY W. BLUNDEN
Senior Vice President-Finance and Accounting and
Chief Financial Officer
(Chief Accounting Officer)
(Principal Financial and Accounting Officer)

A signed original of this written statement required by Section 906, or other document authenticating, acknowledging, or otherwise adopting the signatures that appear in typed form within the electronic version of this written statement required by Section 906, has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Form 10-K and shall not be considered filed as part of the Form 10-K.