TAIWAN SEMICONDUCTOR MANUFACTURING CO LTD
Form 6-K
April 13, 2015

1934 Act Registration No. 1-14700

SECURITIES AND EXCHANGE COMMISSION

Washington, DC 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER

PURSUANT TO RULE 13a-16 OR 15d-16 OF

THE SECURITIES EXCHANGE ACT OF 1934

For the month of April 2015

Taiwan Semiconductor Manufacturing Company Ltd.

(Translation of Registrant s Name Into English)

No. 8, Li-Hsin Rd. 6,

Hsinchu Science Park,

Taiwan

(Address of Principal Executive Offices)

(Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.)

Form 20-F x Form 40-F ¨

(Indicate by check mark whether the registrant by furnishing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.)

Yes ¨ No x

(If Yes is marked, indicated below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82: .)

SIGNATURES

Pursuant to the requirements 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.

Taiwan Semiconductor Manufacturing Company Ltd.

Date: April 13, 2015

By /s/ Lora Ho
Lora Ho
Senior Vice President & Chief Financial Officer

To announce the differences between TSMC s 2014 consolidated financial statements on the basis of Taiwan-IFRSs and IFRSs as issued by the IASB.

1. Under International Financial Reporting Standards endorsed by the Financial Supervisory Commission of the Republic of China (Taiwan-IFRSs), Taiwan Semiconductor Manufacturing Company Ltd. (The Company; TSMC) (NYSE:TSM) reported consolidated net income attributable to shareholders of the parent of New Taiwan Dollars (NT$)263,899 million, basic and diluted earnings per share of NT$10.18 in 2014, total assets of NT$1,495,134 million, total liabilities of NT$449,458 million, noncontrolling interests of NT$127 million, and equity attributable to shareholders of the parent of NT$1,045,549 million as of December 31, 2014.

2. For the purpose of filing the annual report on Form 20-F with the U.S. Securities and Exchange Committee, TSMC prepared the consolidated financial statements in accordance with International Financial Reporting Standards (IFRSs) as issued by the International Accounting Standards Board (IASB) and reported consolidated net income attributable to shareholders of the parent of NT$254,301 million, basic and diluted earnings per share of NT$9.81 in 2014, total assets of NT$1,494,853 million, total liabilities of NT$472,492 million, noncontrolling interest of NT$127million, and equity attributable to shareholders of the parent of NT$1,022,234 million as of December 31, 2014.

3. The major differences between TSMC s 2014 consolidated financial statements on the basis of Taiwan-IFRSs and IFRSs as issued by the IASB were the timing of the recognition of 10% income tax on unappropriated earnings and the accounting for retirement benefit plan.

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	Nine Months Ended September 30, 2017				
	Revenues from external customers[a]			Intersegment revenues	Total Revenues
	Contracts with customers	Other[b]	Total		
Mid-Atlantic	$4,260	$(53)	$4,207	$ 15	$ 4,222
Midwest	2,948	210	3,158	(17)	3,141

New England	1,555	(86)	1,469	(8)	1,461
New York	1,161	(37)	1,124	(14)	1,110
ERCOT	520	229	749	4	753
Other Power Regions	439	368	807	(28)	779
Total Competitive Businesses Electric Revenues	10,883	631	11,514	(48)	11,466
Competitive Businesses Natural Gas Revenues	1,237	570	1,807	52	1,859
Competitive Businesses Other Revenues[c]	588	(66)	522	(4)	518
Total Generation Consolidated Operating Revenues	$12,708	$1,135	$13,843	$ —	$ 13,843

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.

(b) Includes revenues from derivatives and leases.

(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $30 million decrease to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the nine months ended September 30, 2017, unrealized mark-to-market losses of $96 million and $47 million for the nine months ended September 30, 2018 and 2017, respectively, and elimination of intersegment revenues.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Revenues net of purchased power and fuel expense (Generation):

	Nine Months Ended September 30, 2018			Nine Months Ended September 30, 2017		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$2,303	$ 45	$2,348	$2,330	$ 81	$2,411
Midwest	2,381	19	2,400	2,129	11	2,140
New England	310	(12)	298	423	(20)	403
New York	832	9	841	708	(1)	707
ERCOT	396	(180)	216	446	(188)	258
Other Power Regions	430	(121)	309	359	(139)	220
Total Revenues net of purchased power and fuel expense for Reportable Segments	6,652	(240)	6,412	6,395	(256)	6,139
Other[b]	164	240	404	162	256	418
Total Generation Revenues net of purchased power and fuel expense	$6,816	$ —	$6,816	$6,557	$ —	$6,557

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $41 million decrease to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the nine months ended September 30, 2017, unrealized mark-to-market losses of $104 million and $161 million for the nine months ended September 30, 2018 and 2017, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 - Early Plant Retirements of $53 million and $8 million decrease to revenue net of purchased power and fuel expense for the nine months ended September 30, 2018 and 2017, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Electric and Gas Revenue by Customer Class (the Utility Registrants):

	Nine Months Ended September 30, 2018						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$2,277	$1,199	$1,054	$1,839	$792	$513	$534
Small commercial & industrial	1,132	306	196	370	104	138	128
Large commercial & industrial	411	174	325	845	632	74	139
Public authorities & electric railroads	36	21	21	44	24	10	10
Other[(a)]	656	181	246	446	145	129	174
Total rate-regulated electric revenues[(b)]	4,512	1,881	1,842	3,544	1,697	864	985
Rate-regulated natural gas revenues							
Residential	—	259	345	68	—	68	—
Small commercial & industrial	—	102	55	31	—	31	—
Large commercial & industrial	—	1	88	7	—	7	—
Transportation	—	16	—	12	—	12	—
Other[(c)]	—	4	49	11	—	11	—
Total rate-regulated natural gas revenues[(d)]	—	382	537	129	—	129	—
Total rate-regulated revenues from contracts with customers	4,512	2,263	2,379	3,673	1,697	993	985
Other revenues							
Revenues from alternative revenue programs	(27)	2	(23)	7	6	5	(4)
Other rate-regulated electric revenues[(e)]	23	10	10	8	5	3	—
Other rate-regulated natural gas revenues[(e)]	—	—	3	—	—	—	—
Total other revenues	(4)	12	(10)	15	11	8	(4)
Total rate-regulated revenues for reportable segments	$4,508	$2,275	$2,369	$3,688	$1,708	$1,001	$981

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Nine Months Ended September 30, 2017						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$2,071	$1,147	$1,038	$1,740	$751	$505	$484
Small commercial & industrial	1,035	303	193	373	105	139	129
Large commercial & industrial	346	168	329	814	593	78	143
Public authorities & electric railroads	33	23	23	45	24	11	10
Other[(a)]	671	151	222	398	148	121	140
Total rate-regulated electric revenues[(b)]	4,156	1,792	1,805	3,370	1,621	854	906
Rate-regulated natural gas revenues							
Residential	—	225	289	57	—	57	—
Small commercial & industrial	—	90	51	25	—	25	—
Large commercial & industrial	—	—	82	5	—	5	—
Transportation	—	16	—	11	—	11	—
Other[(c)]	—	8	20	7	—	7	—
Total rate-regulated natural gas revenues[(d)]	—	339	442	105	—	105	—
Total rate-regulated revenues from contracts with customers	4,156	2,131	2,247	3,475	1,621	959	906
Other revenues							
Revenues from alternative revenue programs	48	—	102	41	23	9	9
Other rate-regulated electric revenues[(e)]	23	10	11	8	5	3	—
Other rate-regulated natural gas revenues[(e)]	—	—	3	—	—	—	—
Other revenues[(f)]	—	—	—	33	—	—	—
Total other revenues	71	10	116	82	28	12	9
Total rate-regulated revenues for reportable segments	$4,227	$2,141	$2,363	$3,557	$1,649	$971	$915

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates of $23 million, $5 million, $5 million, $11 million, $5 million, $6 million and $2 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the nine months ended September 30, 2018 and $12 million, $4 million, $5 million, $2 million, $4 million, $6 million and $2 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the nine months ended September 30, 2017.
(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates of less than $1 million and $13 million at PECO and BGE, respectively, for the nine months ended September 30, 2018 and less than $1 million and $7 million at PECO and BGE, respectively, for the nine months ended September 30, 2017.
(e) Includes late payment charge revenues.
(f) Includes operating revenues from affiliates of $33 million at PHI for the nine months ended September 30, 2017.

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Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations
(Dollars in millions except per share data, unless otherwise noted)
Exelon
Executive Overview
Exelon, a utility services holding company, operates through the following principal subsidiaries:

- Generation, whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services.
- ComEd, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in northern Illinois, including the City of Chicago.
- PECO, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- BGE, whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and gas distribution services in central Maryland, including the City of Baltimore.
- Pepco, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.
- DPL, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.
- ACE, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in southern New Jersey.

Pepco, DPL and ACE are operating companies of PHI, which is a utility services holding company and a wholly owned subsidiary of Exelon.
Exelon has twelve reportable segments consisting of Generation’s six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI's three utility reportable segments (Pepco, DPL and ACE). See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.
Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of corporate governance support services including corporate strategy and development, legal, human resources, information technology, finance, real estate, security, corporate communications and

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supply at cost. The costs of these services are directly charged or allocated to the applicable operating segments. The services are provided pursuant to service agreements. Additionally, the results of Exelon's corporate operations include interest costs income from various investment and financing activities.

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHISCO and the participating operating subsidiaries.

Exelon's consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

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Financial Results of Operations
GAAP Results of Operations
The following tables set forth Exelon's GAAP consolidated results of operations for the three and nine months ended September 30, 2018 compared to the same period in 2017. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended September 30, 2018							2017	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon	Variance
Operating revenues	$5,278	$1,598	$757	$731	$1,361	$(322)	$9,403	$8,768	$ 635
Purchased power and fuel expense	2,980	619	263	272	509	(311)	4,332	3,542	(790)
Revenue net of purchased power and fuel expense[(a)]	2,298	979	494	459	852	(11)	5,071	5,226	(155)
Other operating expenses									
Operating and maintenance	1,370	337	219	182	292	(54)	2,346	2,275	(71)
Depreciation and amortization	468	237	75	110	192	23	1,105	1,002	(103)
Taxes other than income	143	82	46	64	123	11	469	456	(13)
Total other operating expenses	1,981	656	340	356	607	(20)	3,920	3,733	(187)
(Loss) gain on sales of assets and businesses	(6)	—	—	—	—	1	(5)	(1)	(4)
Bargain purchase gain	—	—	—	—	—	—	—	7	(7)
Operating income	311	323	154	103	245	10	1,146	1,499	(353)
Other income and (deductions)									
Interest expense, net	(101)	(85)	(32)	(27)	(65)	(83)	(393)	(386)	(7)
Other, net	179	7	2	5	11	(10)	194	210	(16)
Total other income and (deductions)	78	(78)	(30)	(22)	(54)	(93)	(199)	(176)	(23)
Income (loss) before income taxes	389	245	124	81	191	(83)	947	1,323	(376)
Income taxes	78	52	(2)	18	4	(13)	137	451	314
Equity in (losses) earnings of unconsolidated affiliates	(11)	—	—	—	—	1	(10)	(7)	(3)
Net income (loss)	300	193	126	63	187	(69)	800	865	(65)
Net income attributable to noncontrolling interests	66	—	—	—	—	1	67	42	(25)
Net income (loss) attributable to common shareholders	$234	$193	$126	$63	$187	$(70)	$733	$823	$ (90)

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	Nine Months Ended September 30, 2018								Favorable
								2017	(Unfavorable)
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon	Variance
Operating revenues	$15,368	$4,508	$2,275	$2,369	$3,688	$(1,038)	$27,170	$25,180	$ 1,990
Purchased power and fuel expense	8,552	1,702	818	881	1,410	(989)	12,374	10,527	(1,847)
Revenue net of purchased power and fuel expense[(a)]	6,816	2,806	1,457	1,488	2,278	(49)	14,796	14,653	143
Other operating expenses									
Operating and maintenance	4,126	974	686	578	857	(185)	7,036	7,658	622
Depreciation and amortization	1,383	696	224	358	555	68	3,284	2,814	(470)
Taxes other than income	414	238	125	188	343	34	1,342	1,313	(29)
Total other operating expenses	5,923	1,908	1,035	1,124	1,755	(83)	11,662	11,785	123
Gain on sales of assets and businesses	48	5	1	1	—	—	55	4	51
Bargain purchase gain	—	—	—	—	—	—	—	233	(233)
Operating income	941	903	423	365	523	34	3,189	3,105	84
Other income and (deductions)									
Interest expense, net	(305)	(261)	(96)	(78)	(193)	(205)	(1,138)	(1,194)	56
Other, net	164	21	4	14	33	(24)	212	643	(431)
Total other income and (deductions)	(141)	(240)	(92)	(64)	(160)	(229)	(926)	(551)	(375)
Income (loss) before income taxes	800	663	331	301	363	(195)	2,263	2,554	(291)
Income taxes	110	140	(5)	59	28	(70)	262	601	339
Equity in (losses) earnings of unconsolidated affiliates	(23)	—	—	—	1	—	(22)	(25)	3
Net income (loss)	667	523	336	242	336	(125)	1,979	1,928	51
Net income attributable to noncontrolling interests	120	—	—	—	—	1	121	21	(100)
Net income (loss) attributable to common shareholders	$547	$523	$336	$242	$336	$(126)	$1,858	$1,907	$ (49)

(a) The Registrants evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrants believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate their operational performance. Revenues net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. Exelon's Net income attributable to common shareholders was $733 million for the three months ended September 30, 2018 as compared to $823 million for the three months ended September 30, 2017, and diluted earnings per average common share were $0.76 for the three months ended September 30, 2018 as compared to $0.85 for the three months ended September 30, 2017.

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Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by $155 million for the three months ended September 30, 2018 compared to the same period in 2017 primarily due to the following factors:

- Decrease of $121 million at Generation primarily due to the absence of EGTP revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017, lower realized energy prices, lower energy efficiency revenues and decreased revenues related to the sale of Generation's electrical contracting business in 2018 and increased nuclear outage days, partially offset by the impact of Illinois ZES and increased capacity prices;
- Decrease of $113 million across all Utility Registrants, primarily reflecting lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates, partially offset by regulatory rate increases at ComEd, Pepco, DPL and ACE; and
- Increase of $58 million at PECO, DPL and ACE primarily due to favorable weather conditions and volumes within their respective service territories.

Operating and maintenance expense increased by $71 million for the three months ended September 30, 2018 as compared to the same period in 2017 primarily due to the following factors:

- Increase of $84 million at Generation due to a charge associated with a remeasurement of the Oyster Creek ARO;
- Increase of $40 million at Generation due to higher nuclear refueling outage costs;
- Increase of $22 million at Pepco due to a charge associated with a remeasurement of the Buzzard Point ARO; and
- Decrease of $50 million at Generation in labor, contracting and materials expense due to decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business in 2018.

Depreciation and amortization expense increased by $103 million for the three months ended September 30, 2018 as compared to the same period in 2017 primarily due to ongoing capital expenditures across all operating companies, accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities, increased amortization of Pepco's DC PLUG regulatory asset (an equal and offsetting amount has been reflected in Operating revenues), partially offset by certain regulatory assets that became fully amortized as of December 31, 2017 for BGE.

Other, net decreased by $16 million primarily due to lower net unrealized and realized gains on NDT funds at Generation for the three months ended September 30, 2018 compared to the same period in 2017.

Exelon’s effective income tax rates for the three months ended September 30, 2018 and 2017 were 14.5% and 34.1%, respectively. The decrease in the effective income tax rate for the three months ended September 30, 2018 compared to the same period in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA at all Registrants, which is predominantly offset in Operating revenues at the Utility Registrants for the anticipated pass back of the tax savings through customer rates. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on TCJA's impact on regulatory proceedings.

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Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. Exelon's Net income attributable to common shareholders was $1,858 million for the nine months ended September 30, 2018 compared to $1,907 million for the nine months ended September 30, 2017, and diluted earnings per average common share were $1.92 for the nine months ended September 30, 2018 compared to $2.02 for the nine months ended September 30, 2017.

Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $143 million for the nine months ended September 30, 2018 as compared to the same period in 2017. The year-over-year increase in Revenue net of purchased power and fuel expense was primarily due to the following factors:

- Increase of $202 million at Generation primarily due to impact of the New York CES and Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), increased capacity prices, the acquisition of the FitzPatrick nuclear facility and decreased nuclear outage days, the addition of two combined-cycle gas turbines in Texas and the impacts of Generation's natural gas portfolio, partially offset by lower realized energy prices, the absence of EGTP revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017, lower energy efficiency revenues and decreased revenues related to the sale of Generation's electrical contracting business in 2018;
- Increase of $57 million at Generation due to lower mark-to-market losses;
- Increase of $132 million at PECO, DPL and ACE primarily due to favorable weather conditions and volumes within their respective service territories;
- Increase of $33 million due to higher mutual assistance revenues across all Utility Registrants, primarily at ComEd;
- Decrease of $95 million at ComEd primarily due to lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to FEJA; and
- Decrease of $274 million in electric and gas revenues across all Utility Registrants, primarily reflecting lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates, partially offset by higher utility revenues due to regulatory rate increases at ComEd, BGE, Pepco, DPL and ACE.

Operating and maintenance expense decreased by $622 million for the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to the following factors:

- Decrease of $411 million at Generation due to long-lived asset impairments primarily related to the EGTP assets held for sale in 2017;
- Decrease of $163 million at Generation in labor, contracting and materials expense due to decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business in 2018.
- Decrease of $95 million at ComEd primarily due to the change to defer and recover over time energy efficiency costs pursuant to FEJA;
- Decrease of $66 million at Generation due to lower merger-related costs;
- Decrease of $56 million at Generation due to lower nuclear refueling outage costs;
- Decrease of $32 million due to a supplemental NEIL insurance distribution at Generation;

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- Increase of $47 million due to higher one-time charges related to Generation's decision to early retire the Oyster Creek nuclear facility in 2018, including a remeasurement to the ARO, compared to one-time charges related to Generation’s decision to early retire the TMI nuclear facility in 2017;
- Increase of $33 million due to higher mutual assistance expenses across all Utility Registrants, primarily at ComEd;
- Increase of $97 million at PECO and BGE due to increased storm costs; and
- Increase of $22 million at Pepco due to a charge associated with a remeasurement of the Buzzard Point ARO.

Depreciation and amortization expense increased by $470 million for the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to increased depreciation expense as a result of ongoing capital expenditures across all operating companies, accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities, increased amortization of Pepco's DC PLUG regulatory asset (an equal and offsetting amount has been reflected in Operating revenues), partially offset by certain regulatory assets that became fully amortized as of December 31, 2017 for BGE.

Taxes other than income increased due to increased gross receipts tax accruals at PECO and Pepco for the nine months ended September 30, 2018 compared to the same period in 2017.

Gain on sales of assets and businesses increased by $51 million for the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to Generation's sale of its electrical contracting business.

Bargain purchase gain decreased by $233 million due to the gain associated with the FitzPatrick acquisition in the first quarter of 2017.

Interest expense, net decreased by $56 million due to retirement of long-term debt.

Other, net decreased by $431 million primarily due to lower net unrealized and realized gains on NDT funds at Generation for the nine months ended September 30, 2018 compared to the same period in 2017.

Exelon’s effective income tax rates for the nine months ended September 30, 2018 and 2017 were 11.6% and 23.5%, respectively. The decrease in the effective income tax rate for the nine months ended September 30, 2018 compared to the same period in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA at all Registrants, which is offset in Operating revenues at the Utility Registrants for the anticipated pass back of the tax savings through customer rates. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on TCJA's impact on regulatory proceedings.

For additional information regarding the financial results for the three and nine months ended September 30, 2018, including explanation of the non-GAAP measure Revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Registrant below.

Adjusted (non-GAAP) Operating Earnings

Exelon’s adjusted (non-GAAP) operating earnings for the three months ended September 30, 2018 were $856 million, or $0.88 per diluted share, compared with adjusted (non-GAAP) operating earnings

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of $820 million, or $0.85 per diluted share for the same period in 2017. Exelon's adjusted (non-GAAP) operating earnings for the nine months ended September 30, 2018 were $2,467 million, or $2.55 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,943 million, or $2.06 per diluted share for the same period in 2017. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of period-over-period operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

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The following tables provide a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and nine months ended September 30, 2018 compared to the same period in 2017.

	Three Months Ended September 30,			
	2018		2017	
(All amounts in millions after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$733	$ 0.76	$823	$ 0.85
Mark-to-Market Impact of Economic Hedging Activities[(a)] (net of taxes of $20 and $29, respectively)	(55)	(0.06)	(45)	(0.05)
Unrealized Gains Related to NDT Fund Investments[(b)] (net of taxes of $4 and $51, respectively)	(53)	(0.06)	(67)	(0.07)
Amortization of Commodity Contract Intangibles[(c)] (net of taxes of $0 and $8, respectively)	—	—	12	0.01
Merger and Integration Costs[(d)] (net of taxes of $0 and $1, respectively)	—	—	(1)	—
Long-Lived Asset Impairments[(f)] (net of taxes of $2 and $16, respectively)	6	0.01	24	0.03
Plant Retirements and Divestitures[(g)] (net of taxes of $70 and $47, respectively)	202	0.21	71	0.08
Cost Management Program[(h)] (net of taxes of $4 and $8, respectively)	13	0.01	13	0.01
Bargain Purchase Gain[(i)] (net of taxes of $0 and $0, respectively)	—	—	(7)	(0.01)
Asset Retirement Obligation[(n)] (net of taxes of $6 and $1, respectively)	16	0.02	(2)	—
Change in Environmental Liabilities (net of taxes of $3 and $0, respectively)	(9)	(0.01)	—	—
Reassessment of Deferred Income Taxes[(k)] (entire amount represents tax expense)	(18)	(0.02)	(21)	(0.02)
Noncontrolling Interests[(m)] (net of taxes of $4 and $4, respectively)	21	0.02	20	0.02
Adjusted (non-GAAP) Operating Earnings	$856	$ 0.88	$820	$ 0.85

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(All amounts in millions after tax)	Nine Months Ended September 30, 2018		2017	
		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$1,858	$ 1.92	$1,907	$ 2.02
Mark-to-Market Impact of Economic Hedging Activities(a) (net of taxes of $26 and $62, respectively)	74	0.08	97	0.10
Unrealized Losses (Gains) Related to NDT Fund Investments(b) (net of taxes of $118 and $181, respectively)	94	0.10	(211)	(0.22)
Amortization of Commodity Contract Intangibles(c) (net of taxes of $0 and $17, respectively)	—	—	27	0.03
Merger and Integration Costs(d) (net of taxes of $1 and $24, respectively)	5	—	39	0.04
Merger Commitments(e) (net of taxes of $0 and $137, respectively)	—	—	(137)	(0.15)
Long-Lived Asset Impairments(f) (net of taxes of $13 and $188, respectively)	36	0.04	293	0.31
Plant Retirements and Divestitures(g) (net of taxes of $148 and $89, respectively)	422	0.43	137	0.15
Cost Management Program(h) (net of taxes of $10 and $15, respectively)	29	0.03	24	0.03
Bargain Purchase Gain(i) (net of taxes of $0 and $0, respectively)	—	—	(233)	(0.25)
Asset Retirement Obligation(n) (net of taxes of $6 and $1, respectively)	16	0.02	(2)	—
Change in Environmental Liabilities (net of taxes of $1 and $0, respectively)	(4)	—	—	—
Like-Kind Exchange Tax Position(j) (net of taxes of $0 and $66, respectively)	—	—	(26)	(0.03)
Reassessment of Deferred Income Taxes(k) (entire amount represents tax expense)	(27)	(0.03)	(42)	(0.04)
Tax Settlements(l) (net of taxes of $0 and $1, respectively)	—	—	(5)	(0.01)
Noncontrolling Interests(m) (net of taxes of $9 and $16, respectively)	(36)	(0.04)	75	0.08
Adjusted (non-GAAP) Operating Earnings	$2,467	$ 2.55	$1,943	$ 2.06

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates for 2018 and 2017 ranged from 26.0 percent to 29.0 percent and 39.0 percent to 41.0 percent, respectively. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 7.7 percent and 43.2 percent for the three months ended September 30, 2018 and 2017, respectively. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 55.5 percent and 46.2 percent for the nine months ended September 30, 2018 and 2017, respectively.

(a) Primarily reflects the impact of net gains and losses on Generation's economic hedging activities.

(b) Reflects the impact of net unrealized gains and losses on Generation's NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.

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(c) Reflects the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the ConEdison Solutions and FitzPatrick acquisitions.

(d) Primarily reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2017, reflects costs related to the PHI and FitzPatrick acquisitions, offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs. In 2018, reflects costs related to the PHI acquisition.

(e) Primarily reflects a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.

(f) Primarily reflects charges to earnings related to the impairment of the EGTP assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.

(g) Primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's previous decision to early retire the Three Mile Island nuclear facility in 2017. In 2018, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility, a charge associated with a remeasurement of the Oyster Creek ARO and accelerated depreciation and amortization expenses associated with the 2017 decision to early retire the Three Mile Island nuclear facility, partially offset by a gain associated with Generation's sale of its electrical contracting business.

(h) Primarily represents severance and reorganization costs related to a cost management program.

(i) Represents the excess fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.

(j) Reflects adjustments to income tax, penalties and interest expenses in the second quarter of 2017 as a result of the finalization of the IRS tax computation related to Exelon’s like-kind exchange tax position.

(k) Reflects the changes in the Illinois and District of Columbia statutory tax rate and changes in forecasted apportionment in 2017. In 2018, reflects an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA) and changes in forecasted apportionment.

(l) Reflects benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI’s unregulated business interests.

(m) Reflects elimination from Generation’s results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.

(n) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2017. In 2018, reflects an increase at Pepco related primarily to asbestos identified at its Buzzard Point property.

Significant 2018 Transactions and Developments

Regulatory Implications of the Tax Cuts and Jobs Act (TCJA)

The Utility Registrants have made filings with their respective State regulators to begin passing back to customers the ongoing annual tax savings resulting from the TCJA. The amounts being proposed to be passed back to customers reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. The Utility Registrants have identified over $675 million in ongoing annual savings to be returned to customers related to TCJA from their distribution utility operations. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Early Plant Retirements

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in 2018. On September 17, 2018, Oyster Creek permanently ceased generation operations. Because of the decision to early retire Oyster Creek in 2018, Exelon and Generation recognized certain one-time charges in the first quarter of 2018 related to a materials and supplies inventory reserve adjustment, employee-related costs and construction work-in-progress impairments, among other items.

On July 31, 2018, Generation entered into an agreement with Holtec International and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC, for the sale and decommissioning of Oyster Creek. See

Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

On May 30, 2017, Generation announced it will permanently cease generation operations at Three Mile Island Generating Station (TMI) on or about September 30, 2019. The plant is currently committed to operate through May 2019.

As a result of the early nuclear plant retirement decisions at Oyster Creek and TMI, Exelon and Generation will also recognize annual incremental non-cash charges to earnings stemming from

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shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions were also recorded. The following table summarizes the actual incremental non-cash expense item incurred in 2018 and the estimated amount of incremental non-cash expense items expected to be incurred in 2018 and 2019 due to the early retirement decisions.

Income statement expense (pre-tax)	Actual Nine Months Ended September 30, 2018	Projected[(a)] 2018	2019
Depreciation and amortization[(b)]			
Accelerated depreciation[(c)]	$ 441	$550	$330
Accelerated nuclear fuel amortization	52	55	5
Operating and maintenance[(d)]	32	35	5
Total	$ 525	$640	$340

(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

(b) Reflects incremental accelerated depreciation and amortization for TMI and Oyster Creek for the nine months ended September 30, 2018. The Oyster Creek year-to-date amounts are from February 2, 2018 through September 17, 2018.

(c) Reflects incremental accelerated depreciation of plant assets, including any ARC.

(d) Primarily includes materials and supplies inventory reserve adjustments, employee-related costs and CWIP impairments.

In 2017, PSEG also made public financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. Although Salem is committed to operate through May 2021, the plant faces continued economic challenges and PSEG, as the operator of the plant, is exploring all options.

On May 23, 2018, the Governor of New Jersey signed new legislation, which became effective immediately, that will establish a ZEC program providing compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Under the new legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey, including ACE, will be required to purchase those ZECs. The NJBPU has 180 days from the effective date to establish procedures for implementation of the ZEC program and 330 days from the effective date to determine which nuclear power plants are selected to receive ZECs under the program. Assuming the successful implementation of the New Jersey ZEC program and the selection of Salem as one of the qualifying facilities, the New Jersey ZEC program has the potential to mitigate the heightened risk of earlier retirement for Salem. See Note 6 — Regulatory Matters and Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information on the new legislation and the New Jersey ZEC program.

On March 29, 2018, based on ISO-NE capacity auction results for the 2021 - 2022 planning year in which Mystic Unit 9 did not clear, Generation announced it had formally notified grid operator ISO-NE of its plans to early retire its Mystic Generating Station assets on June 1, 2022 absent any interim and long-term solutions for reliability and regional fuel security. The ISO-NE announced that it would take a three-step approach to fuel security. First, on May 1, 2018, ISO-NE made a filing with FERC requesting waiver of certain tariff provisions to allow it to retain Mystic Units 8 and 9 for fuel security for the 2022 - 2024 planning years. Second, ISO-NE planned to file tariff revisions to allow it to retain other resources for fuel security in the capacity market if necessary in the future. Third, ISO-NE stated its intention to work with stakeholders to develop long-term market rule changes to address system resiliency considering significant reliability risks identified in ISO-NE's January 2018 fuel security report. Changes to market rules are necessary because critical units to the region, such as Mystic Units 8 and 9, cannot

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recover future operating costs including the cost of procuring fuel. As a result of these developments, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group during the first quarter of 2018 and no impairment charge was required.

On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 and 9 for the period between June 1, 2022 - May 31, 2024.

On July 2, 2018, FERC issued an order denying ISO-NE's May 1, 2018, waiver request on procedural grounds but accepting ISO-NE's conclusions that retirement of Mystic Units 8 and 9 could cause a violation of mandatory reliability standards as soon as 2022. Accordingly, FERC ordered ISO-NE to (i) make a filing within 60 days providing for the filing of a short-term cost-of-service agreement to address demonstrated fuel security concerns and (ii) make a filing by July 1, 2019 proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns. FERC also extended the deadline by which Generation must make a retirement decision for Mystic Units 8 and 9 to January 4, 2019. On August 31, 2018, ISO-NE filed a compliance filing in response to FERC's July 2, 2018 order proposing short-term tariff changes to permit it to retain a resource for fuel security reliability reasons. A number of parties, including Generation, have submitted comments on the proposal, which is pending before FERC.

On July 13, 2018, FERC issued an order accepting the cost-of-service agreement for filing, making findings on certain issues and establishing hearing procedures on an expedited schedule. Further developments such as the failure of ISO-NE to adopt interim and long-term solutions for reliability and fuel security could potentially result in future impairments of the New England asset group, which could be material. See Note 7 — Impairment of Long-Lived Assets and Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

Illinois ZEC Procurement

Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation’s Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue. Winning bidders are entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. During the three months ended September 30, 2018, Generation recognized revenue of $61 million. During the nine months ended September 30, 2018, Generation recognized revenue of $315 million, of which $150 million related to ZECs generated from June 1, 2017 through December 31, 2017.

Westinghouse Electric Company LLC Bankruptcy

On March 29, 2017, Westinghouse Electric Company LLC (Westinghouse) and its affiliated debtors filed petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. On January 4, 2018, Westinghouse announced its agreement to be purchased by an affiliate of Brookfield Business Partners, LLC (Brookfield) for approximately $4.6 billion. On March 28, 2018, the Bankruptcy Court entered an Order confirming the Debtor's Second Amended Joint Plan of Reorganization which provides for the transaction with Brookfield. The transaction closed on August 1, 2018. Exelon had contracts with Westinghouse primarily related to Generation's purchase of nuclear fuel, as well as a variety of services and equipment purchases associated with the operation and maintenance of nuclear generating stations. In conjunction with the confirmation hearing, Exelon had filed a reservation of rights regarding reorganizing Westinghouse's assumption of all Exelon contracts. Exelon reached an agreement with Brookfield, and all Exelon contracts were assumed by Brookfield on the closing date.

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Utility Rates and Base Rate Proceedings

The Utility Registrants file base rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future results of operations, cash flows and financial position.

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2018. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant	Jurisdiction	Approved Revenue Requirement Increase (Decrease) (in millions)	Approved Return on Equity	Completion Date	Rate Effective Date
Pepco	District of Columbia (Electric)	$ (24)	9.525 %	August 9, 2018	August 13, 2018
Pepco	Maryland (Electric)	$ (15)	9.5 %	May 31, 2018	June 1, 2018
DPL	Delaware (Electric)	$ (7)	9.7 %	August 21, 2018	March 17, 2018
DPL	Maryland (Electric)	$ 13	9.5 %	February 9, 2018	September 5, 2018

Pending Distribution Base Rate Case Proceedings

Registrant	Jurisdiction	Requested or Settlement Revenue Requirement Increase (Decrease) (in millions)	Requested or Settlement Return on Equity	Filing or Settlement Date	Expected Completion Timing
ComEd	Illinois (Electric)	$ (23)	8.69 %	April 16, 2018	Fourth quarter 2018
PECO	Pennsylvania (Electric)	$ 25	N/A[(a)]	August 28, 2018	Fourth quarter 2018
BGE	Maryland (Natural Gas)	$ 61	10.50 %	June 8, 2018 (Updated on August 24, 2018 and October 12, 2018)	First quarter 2019
DPL	Delaware (Natural Gas)	$ (4)	9.70 %	September 7, 2018 (Updated on October 2, 2018)	Fourth quarter 2018
ACE	New Jersey (Electric)	$ 109	10.10 %	August 21, 2018	Third quarter 2019

(a) No overall ROE was specified in the partial settlement agreement.

See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these base rate case proceedings.

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Transmission Formula Rate

The following total (decreases)/increases were included in ComEd's, BGE's, Pepco's, DPL's and ACE's 2018 annual electric transmission formula rate updates.

	2018				
Annual Transmission Updates[a][b]	ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement (decrease) increase	$(44)	$10	$6	$14	$4
Annual reconciliation increase (decrease)	18	4	2	13	(4)
Dedicated facilities increase[c]	—	12	—	—	—
Total revenue requirement (decrease) increase	$(26)	$26	$8	$27	$—
Allowed return on rate base[d]	8.32%	7.61%	7.82%	7.29%	8.02%
Allowed ROE[e]	11.50%	10.50%	10.50%	10.50%	10.50%

(a) All rates are effective June 2018, subject to review by the FERC and other parties, which is due by fourth quarter 2018.

(b) The initial revenue requirement changes reflect the annual benefit of lower income tax rates effective January 1, 2018 resulting from the enactment of the TCJA of $69 million, $18 million, $13 million, $12 million and $11 million for ComEd, BGE, Pepco, DPL and ACE, respectively. They do not reflect the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. See further discussion above.

(c) BGE's transmission revenues include a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to a specifically designated load by BGE.

(d) Represents the weighted average debt and equity return on transmission rate bases.

(e) As part of the FERC-approved settlement of ComEd’s 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.

PECO Transmission Formula Rate

On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO’s transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO’s annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. PECO cannot predict the final outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue decrease of $6 million included an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

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Winter Storm-Related Costs

During March 2018 there were powerful nor'easter storms that brought a mix of heavy snow, ice and high sustained winds and gusts to the region that interrupted electric service delivery to customers in PECO's, BGE's, Pepco's, DPL's and ACE's service territories. Restoration efforts included significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies, which resulted in incremental operating and maintenance expense and incremental capital expenditures in the first quarter of 2018 for PECO, BGE, PHI, Pepco, DPL and ACE. In addition, PHI, Pepco, DPL and ACE recorded regulatory assets for amounts that are probable of recovery through customer rates. The impacts recorded by the Registrants for the nine months ended September 30, 2018 are presented below:

		(in millions)	
	Customer Outages	Incremental Operating & Maintenance	Incremental Capital Expenditures
Exelon	1,727,000	$ 88 (b)	$ 89
PECO	750,000	53	35
BGE	425,000	31	15
PHI(a)	552,000	4 (b)	39
Pepco	182,000	2 (b)	4
DPL	138,000	2 (b)	4
ACE	232,000	— (b)	31

(a) PHI reflects the consolidated customer outages, incremental operating & maintenance and incremental capital expenditures of Pepco, DPL and ACE.

(b) Excludes amounts that were deferred and recognized as regulatory assets at Exelon, PHI, Pepco, DPL and ACE of $28 million, $28 million, $7 million, $1 million and $20 million, respectively.

Exelon’s Strategy and Outlook for 2018 and Beyond

Exelon’s value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon’s regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- The Utility Registrants provide a foundation for steadily growing earnings, which translates to a stable currency in our stock.
- Generation’s competitive businesses provide free cash flow to invest primarily in the utilities and in long-term, contracted assets and to reduce debt.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

Exelon’s utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Utility Registrants only invest in rate base where it provides a benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Utility Registrants make these investments at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results. Additionally, the Utility Registrants anticipate making significant future investments in smart meter

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technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation’s competitive businesses create value for customers by providing innovative energy solutions and reliable, clean and affordable energy. Generation’s electricity generation strategy is to pursue opportunities that provide stable revenues and generation to load matching to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation’s customer-facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon’s financial priorities are to maintain investment grade credit metrics at each of the Registrants, to maintain optimal capital structure and to return value to Exelon’s shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon's Board of Directors has approved a dividend policy providing a raise of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Various market, financial, regulatory, legislative and operational factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. One key issue is ensuring the ability to properly value nuclear generation assets in the market, solutions to which Exelon is actively pursuing in a variety of jurisdictions and venues. See ITEM 1A. RISK FACTORS of the Exelon 2017 Form 10-K for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon’s financial strategy. In August 2015, Exelon announced a cost management program focused on cost savings of approximately $400 million at BSC and Generation, which was fully realized in 2018. Approximately 75% of the savings were related to Generation, with the remaining amount related to the Utility Registrants. In November 2017, Exelon announced a commitment for an additional $250 million of cost savings, primarily at Generation, to be achieved by 2020. In November 2018, Exelon announced the elimination of an approximately additional $200 million of annual ongoing costs, through initiatives primarily at Generation and BSC, by 2021. Approximately $150 million is expected to be related to Generation, with the remaining amount related to the Utility Registrants. These actions are in response to the continuing economic challenges confronting all parts of Exelon’s business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity.

Growth Opportunities

Management continually evaluates growth opportunities aligned with Exelon’s businesses, assets and markets, leveraging Exelon’s expertise in those areas and offering sustainable returns.

Regulated Energy Businesses. The PHI merger provides an opportunity to accelerate Exelon’s regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $28 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $11 billion by the end of 2022. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made at the lowest reasonable cost to customers.

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See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements Exelon 2017 Form 10-K for additional information on the Smart Meter and Smart Grid Initiatives and infrastructure development and enhancement programs.

Competitive Energy Businesses. Generation continually assesses the optimal structure and composition of its generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to ensure appropriate valuation of its generation assets, in part through public policy efforts, identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, and identify emerging technologies where strategic investments provide the option for significant future growth or influence in market development.

Liquidity Considerations

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon Corporate, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.6 billion, $5.3 billion, $1 billion, $0.6 billion, $0.6 billion, $0.3 billion, $0.3 billion and $0.3 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion.

For additional information regarding the Registrants' liquidity for the nine months ended September 30, 2018, see Liquidity and Capital Resources discussion below.

Project Financing

Generation utilizes individual project financings as a means to finance the construction of various generating asset projects. Project financing is based upon a nonrecourse financial structure, in which project debt and equity used to finance the project are paid back from the cash generated by the newly constructed asset once operational. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, or restructured, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt.

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Other Key Business Drivers and Management Strategies
Power Markets
Price of Fuels
The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).
FERC Inquiry on Resiliency
On August 23, 2017, the DOE staff released its report on the reliability of the electric grid. One aspect of the wide-ranging report is the DOE's recognition that the electricity markets do not currently value the resiliency provided by baseload generation, such as nuclear plants. On September 28, 2017, the DOE issued a Notice of Proposed Rulemaking (NOPR) that would entitle certain eligible resilient generating units (i.e., those located in organized markets, with a 90-day supply of fuel on site, not already subject to state cost of service regulation and satisfying certain other requirements) to recover fully allocated costs and earn a fair return on equity on their investment. On January 8, 2018, FERC issued an order terminating the rulemaking docket that it initiated to address the proposed rule in the DOE NOPR, concluding the proposed rule did not sufficiently demonstrate there is a resiliency issue and that it proposed a remedy that did not appear to be just, reasonable and nondiscriminatory as required under the Federal Power Act. At the same time, FERC initiated a new proceeding to consider resiliency challenges to the bulk power system and evaluate whether additional FERC action to address resiliency would be appropriate. FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Thereafter, interested parties submitted reply comments on May 9, 2018, and a few parties submitted further replies. Exelon has been and will continue to be an active participant in these proceedings but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.
Complaints and PJM Filing at FERC Seeking to Mitigate ZEC Programs
PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new gas-fired resources.
On January 9, 2017, EPSA filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. A similar complaint also against PJM was filed at FERC on May 31, 2018. These complaints generally allege that the relevant MOPR should be expanded to also apply to existing resources including those receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS programs that have generally not been subject to a MOPR. However, if successful, for Generation's facilities in PJM and NYISO that are currently receiving ZEC compensation (Quad Cities, Ginna, Fitzpatrick and Nine Mile Point), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in future capacity auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any mitigation of these generating resources could have a material effect on Exelon's

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and Generation’s future cash flows and results of operations. The same risk would also exist for the Salem facility if Salem is selected as an eligible facility under the NJ ZEC program.

Separately, PJM submitted two proposed alternative capacity market reforms in April 2018 for FERC’s consideration. PJM argued that either alternative will resolve any conflict between state policy support for certain resources and the need to ensure reasonable prices for non-supported resources. The first alternative was to implement a twice-run capacity clearing mechanism (known as the repricing proposal) and, if not acceptable to FERC, a second alternative that would expand the existing MOPR to both new and existing generating resources, subject to certain exemptions (known as MOPREx).

In June 2018, FERC issued an order rejecting both of PJM’s proposed alternatives, finding both to be unjust and unreasonable. In the same order, FERC also addressed one of the MOPR complaints involving PJM and concluded based on that complaint and PJM’s filing that PJM’s existing tariff allows resources receiving out-of-market support to affect capacity prices in a manner that will cause unjust and unreasonable and unduly discriminatory rates in PJM regardless of the intent motivating the support. FERC suggested that modifying two elements of PJM’s existing tariff could produce a just and reasonable replacement and asked for initial comments on its proposal by August 28, 2018, later extended to October 2, 2018. First, FERC found that an expansion of the current MOPR mechanism to cover all existing generating resources, regardless of resource type, including those receiving either ZEC or REC compensation, could protect the capacity markets from unwanted price suppression. Second, FERC preliminarily found that a modified version of PJM’s existing Fixed Resource Requirement (FRR) option could enable state subsidized resources and a corresponding amount of load to be removed from the capacity market, thereby alleviating their price suppressive effects on capacity clearing prices. Under this alternative, state supported generating resources would potentially be compensated through mechanisms other than through PJM’s existing market mechanism. FERC established March 21, 2016 as the refund effective date and also allowed PJM to delay its next capacity auction from May 2019 to August 2019 to allow parties time to develop and file proposals in the FERC proceeding, FERC time to determine the appropriate solution and PJM time to implement FERC's solution. On October 2, 2018, Exelon, along with several ratepayer advocates, environmental organizations and other nuclear generators, submitted shared principles supporting a workable new FRR mechanism (as suggested by FERC) and detailing how such a mechanism should be implemented. Exelon also submitted individual comments covering matters not addressed in the shared principles. FERC has not yet issued a decision on the second MOPR complaint involving PJM or the MOPR complaint involving NYISO. It is too early to predict the final outcome of each of these proceedings or their potential financial impact, if any, on Exelon or Generation.

Section 232 Uranium Petition

On January 16, 2018, two Canadian-owned uranium mining companies with operations in the U.S. jointly submitted a petition to the U.S. Department of Commerce (DOC) seeking relief under Section 232 of the Trade Expansion Act of 1962 (as amended) from imports of uranium products, alleging that these imports threaten national security (the Petition). The Trade Expansion Act of 1962 (the Act) was promulgated by Congress to protect essential national security industries whose survival is threatened by imports. As such, the Act authorizes the Secretary of Commerce (the Secretary) to conduct investigations to evaluate the effects of imports of any item on the national security of the U.S. The Petition alleges that the loss of a viable U.S. uranium mining industry would have a significant detrimental impact on the national, energy, and economic security of the U.S. and the ability of the country to sustain an independent nuclear fuel cycle.

On July 18, 2018, the Secretary announced that the DOC has initiated an investigation in response to the petition. The Secretary has 270 days to prepare and submit a report to President Trump, who then has 90 days to act on the Secretary's recommendations. Exelon and Generation cannot currently predict the outcome of this investigation. The relief sought by the petitioners would require U.S. nuclear reactors

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to purchase at least 25% of their uranium needs from domestic mines over the next 10 years, although the DOC will make an independent determination regarding an appropriate remedy should it find that imports impair national security. It is reasonably possible that if this petition is successful the resulting increase in nuclear fuel costs in future periods could have a material, unfavorable impact on Exelon’s and Generation’s results of operations, cash flows and financial positions.

Potential DOE Order Pursuant to Defense Production Act and Federal Power Act

The DOE is considering an Order directing ISOs, for 24 months, to purchase electric energy or generation capacity from a designated list of coal and nuclear generation facilities. Based on a draft memorandum, the Order would be pursuant to DOE's authorities under the Defense Production Act and Federal Power Act, and would forestall any further actions towards retiring, decommissioning, or deactivating coal and nuclear facilities during the term of the Order. The Order would emphasize the importance of grid resiliency, in addition to grid reliability, noting that fuel security and diversity are critical components of resiliency. The DOE recognizes that the underlying economic and regulatory issues are complex and will take time resolve. The Order's 24-month duration would enable DOE to conduct additional analyses to gain a detailed understanding of location-specific vulnerabilities in U.S. energy delivery systems, while preserving certain generation facilities. Exelon has been and will continue to be an active participant in these proceedings but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in relatively flat load growth in electricity for the Utility Registrants. ComEd, PECO, BGE, Pepco, DPL and ACE are projecting load volumes to increase by 0.5%, 1.7%, 0.7%, 0.2%, 1.3% and 4.3% respectively, in 2018 compared to 2017.

Retail Competition

Generation’s retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

Strategic Policy Alignment

As part of its strategic business planning process, Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared first quarter 2018 dividends of $0.345 per share on Exelon's common stock. The first quarter 2018 dividend was paid on March 9, 2018. The dividend increased from the fourth quarter 2017 amount to reflect the Board's decision to raise Exelon's dividend 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Exelon's board of directors declared second quarter 2018 dividends of $0.345 per share on Exelon's common stock and was paid on June 8, 2018.

Exelon's board of directors declared third quarter 2018 dividends of $0.345 per share on Exelon's common stock and was paid on September 10, 2018.

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Exelon's board of directors declared fourth quarter 2018 dividends of $0.345 per share on Exelon's common stock and is payable on December 10, 2018.
All future quarterly dividends require approval by Exelon's Board of Directors.
Hedging Strategy
Exelon’s policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2018 and 2019. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of September 30, 2018, the percentage of expected generation hedged is 98%-101%, 82%-85% and 48%-51% for 2018, 2019, and 2020 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.
Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation’s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 59% of Generation’s uranium concentrate requirements from 2018 through 2022 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon’s and Generation’s results of operations, cash flows and financial positions.
The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.
Environmental Legislative and Regulatory Developments
Exelon was actively involved in the Obama Administration’s development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for fossil-fueled electric generating units, as set forth in the discussion below. These regulations have had a disproportionate adverse impact on coal-fired power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation has not been significantly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil fuel plants.

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Through the issuance of a series of Executive Orders (EO), President Trump has initiated review of a number of EPA and other regulations issued during the Obama Administration, with the expectation that the Administration will seek repeal or significant revision of these rules. Under these EOs, each executive agency is required to evaluate existing regulations and make recommendations regarding repeal, replacement, or modification. The Administration's actions are intended to result in less stringent compliance requirements under air, water, and waste regulations. The exact nature, extent, and timing of the regulatory changes are unknown, as well as the ultimate impact on Exelon's and its subsidiaries results of operations and cash flows.

In particular, the Administration has targeted certain existing EPA regulations for repeal, including notably the Clean Power Plan, as well as revoking many Executive Orders, reports, and guidance issued by the Obama Administration on the topic of climate change or the regulation of greenhouse gases. The Executive Order also disbanded the Interagency Working Group that developed the social cost of carbon used in rulemakings and withdrew all technical support documents supporting the calculation. Other regulations that are under review include the Clean Water Act rule relating to jurisdictional waters of the U.S., the Steam Electric Effluent Guidelines relating to waste water discharges from coal-fired power plants, and the Coal Combustion Residuals rule. The review of final rules could extend over several years as formal notice and comment rulemaking process proceeds.

Air Quality

Mercury and Air Toxics Standard Rule (MATS). On December 16, 2011, the EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two-year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court's opinion on this single issue. On April 27, 2017, the D.C. Circuit granted EPA's motion to hold the litigation in abeyance, pending EPA's review of the MATS rule pursuant to President Trump's EO discussed above. Following EPA's review and determination of its course of action for the MATS rule, the parties will have 30 days to file motions on future proceedings. Notwithstanding the Court's order to hold the litigation in abeyance, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule.

Clean Power Plan. On April 28, 2017, the D.C. Circuit Court issued orders in separate litigation related to the EPA's actions under the Clean Power Plan (CPP) to amend Clean Air Act Section 111(d) regulation of existing fossil-fired electric generating units and Section 111(b) regulation of new fossil-fired electric generating units. In both cases, the Court has determined to hold the litigation in abeyance pending a determination whether the rule should be remanded to the EPA. On October 10, 2017, EPA issued a proposed rule to repeal the CPP in its entirety, based on a proposed change in the Agency's legal interpretation of Clean Air Act Section 111(d) regarding actions that the Agency can consider when establishing the Best System of Emission Reduction ("BSER") for existing power plants. Under the proposed interpretation, the Agency exceeded its authority under the Clean Air Act by regulating beyond individual sources of GHG emissions. The EPA has also issued an advance notice of proposed rulemaking to solicit information on systems of emission reduction that are in accord with the Agency's proposed revised legal interpretation; namely, only by regulating emission reductions that can be implemented at and to individual sources.

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2015 Ozone National Ambient Air Quality Standards (NAAQS). On April 11, 2017, the D.C. Circuit ordered that the consolidated 2015 ozone NAAQS litigation be held in abeyance pending EPA's further review of the 2015 Rule. Concurrent with its review, the Agency issued several rounds of final ozone designations for the 2015 ozone NAAQS in December 2017 and April 2018. On August 1, 2018, EPA filed a status report to the Court that indicated Agency does not intend to revise or repeal the 2015 ozone standard at this time. Subsequently the Court ordered the case reactivated.

Primary SO2 National Ambient Air Quality Standards (NAAQS). On June 8, 2018, the EPA proposed to maintain the primary NAAQS for sulfur dioxide (SO2) at the same level and averaging time as was finalized by EPA in its 2010 SO2 NAAQS update. The schedule for completing this review is established by a consent decree, which sets January 28, 2019 as the deadline for signature on a final decision notice.

Climate Change. Exelon supports comprehensive climate change legislation or regulation which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In June 2018, Exelon joined the Climate Leadership Council, which advocates for a revenue neutral carbon tax and dividend program. In the absence of Federal legislation, the EPA has been reviewing the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ("UNFCCC" or "Convention"). See ITEM 1. BUSINESS, "Air Quality" of the Exelon 2017 Form 10-K for additional information.

Water Quality

Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Handley, Mystic Unit 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, and Salem. See ITEM 1. BUSINESS, "Water Quality" of the Exelon 2017 Form 10-K for additional information.

Solid and Hazardous Waste

In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classified CCR as non-hazardous waste under RCRA, and CCR continued to be regulated by most states subject to coordination with the federal regulations. In July 2018, the EPA issued a final rule amending the 2015 rule that provides more compliance flexibility to the states and owners and operators of coal ash disposal sites. Generation currently does not own or operate any such sites subject to the CCR rule. Generation previously recorded accruals consistent with state regulation for its owned coal ash sites, and as such, the CCR rule is not expected to impact Exelon's and Generation's financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the CCR rule for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

See Note 17 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information related to environmental matters, including the impact of environmental regulation.

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Other Legislative and Regulatory Developments
Delaware Distribution System Investment Charge
On June 14, 2018, the Governor of Delaware signed new Distribution System Investment Charge (DSIC) legislation, which establishes a system improvement charge that provides a mechanism to recover infrastructure investments, allowing for gradual rate increases and limiting frequency of distribution base rate cases. DPL expects to make its first filing in Delaware in the fourth quarter of 2018, with the new charge effective in the first quarter of 2019. While this legislation is expected to support needed infrastructure investment and allow for more timely recovery of those investments, Exelon, PHI and DPL cannot predict the potential financial impact on Exelon, PHI or DPL.
Pennsylvania Alternative Ratemaking
On June 28, 2018, the Governor of Pennsylvania signed new legislation, which authorized the PAPUC to review and approve utility-proposed alternative rate mechanisms, including options such as decoupling mechanisms, formula rates, multi-year rate plans, and performance based rates. Exelon and PECO cannot predict the outcome or the potential financial impact, if any, on Exelon or PECO.
Employees
In January 2017, an election was held at BGE which resulted in union representation for approximately 1,394 employees. BGE and IBEW Local 410 are negotiating an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. Negotiations have been productive and continue. No agreement has been finalized to date and management cannot predict the outcome of such negotiations. Negotiations that began in 2017 for a first collective bargaining agreement with a small unit of employees represented by Local 501 of Operating Engineers at Exelon’s Hyperion Solutions facility are complete and the new CBA will expire in 2021. During 2017, Generation finalized CBAs with the Security Officer unions at LaSalle, Limerick and Quad Cities, which all will expire in 2020 and Dresden expiring in 2021. Additionally, during 2017, Generation acquired and combined two CBAs at Fitzpatrick into one CBA covering both craft and security employees, which will expire in 2023. Generation also successfully finalized the CBA with the IBEW union at TMI, which will expire in 2022. During 2018, Generation finalized its CBA with the Security Officer’s union at Braidwood, which will expire in 2021. Additionally, negotiations are currently underway for the two ACE Local 210 contracts, which expire on October 15, 2018 and December 9, 2018. Both sides are bargaining in good faith and we anticipate a mutually acceptable outcome from these negotiations. As previously reported, there was an organizing effort over approximately 18 ACE control room System Operators. While an election was held with an outcome favorable to Local 210, collective bargaining over this small segment of employees will not commence until the issue of whether the System Operators are NLRA statutory supervisors is determined, and that matter is currently before the NLRB.
Critical Accounting Policies and Estimates
Revenue Recognition (All Registrants)
Sources of Revenue and Determination of Accounting Treatment
The Registrants earn revenues from various business activities including: the sale of power and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail); the sale and delivery of power and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.
The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. The Registrants primarily apply the Revenue from

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Contracts with Customers, Derivative and Alternative Revenue Program (ARP) guidance to recognize revenue as discussed in more detail below.

Revenue from Contracts with Customers

Under the Revenue from Contracts with Customers guidance, the Registrants recognize revenues in the period in which the performance obligations within contracts with customers are satisfied, which generally occurs when power, natural gas, and other energy-related commodities are physically delivered to the customer. Transactions of the Registrants within the scope of Revenue from Contracts with Customers generally include non-derivative agreements, contracts that are designated as normal purchases and normal sales (NPNS), sales to utility customers under regulated service tariffs, and spot-market energy commodity sales, including settlements with independent system operators.

The determination of Generation's and the Utility Registrants' retail power and natural gas sales to individual customers is based on systematic readings of customer meters, generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, revenues may fluctuate monthly as a result of customers electing to use an alternate supplier, since unbilled commodity revenues are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date also impact the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 5 — Accounts Receivable of the Exelon 2017 Form 10-K for additional information on unbilled revenue.

See Note 1 — Significant Accounting Policies and Note 5 — Revenue from Contracts with Customers of the Combined Notes to Consolidated Financial Statements for additional information on the impacts of the new revenue accounting standard effective for annual reporting periods beginning on or after December 15, 2017.

Derivative Revenues

The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that are accounted for as derivatives. These derivative transactions primarily relate to commodity price risk management activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable, unrealized gains and losses from changes in the fair value of open contracts, and realized gains and losses.

Alternative Revenue Program Revenues

Certain of the Utility Registrants' ratemaking mechanisms qualify as Alternative Revenue Programs (ARPs) if they (i) are established by a regulatory order and allow for automatic adjustment to future rates, (ii) provide for additional revenues (above those amounts currently reflected in the price of utility service) that are objectively determinable and probable of recovery, and (iii) allow for the collection of those additional revenues within 24 months following the end of the period in which they were recognized. For mechanisms that meet these criteria, which include the Utility Registrants' formula rate and revenue decoupling mechanisms, the Utility Registrants adjust revenue and record an offsetting regulatory asset or liability once the condition or event allowing additional billing or refund has occurred. The ARP revenues presented in the Utility Registrants' Consolidated Statements of Operations and Comprehensive Income

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include both: (i) the recognition of “originating” ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the “originating” ARP revenues as those amounts are reflected in the price of utility service and recognized as Revenue from Contracts with Customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco and DPL record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC and/or DCPSC in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. Estimates of the current year revenue requirement are based on actual and/or forecasted costs and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred, investments made, allowed ROE, and actions by regulators or courts.

See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — CRITICAL ACCOUNTING POLICIES AND ESTIMATES in Exelon’s, Generation’s, ComEd’s, PECO’s, BGE’s, PHI's, Pepco's, DPL's and ACE's combined 2017 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants’ accounting for AROs, goodwill, purchase accounting, unamortized energy contract assets and liabilities, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies, revenue recognition and allowance for uncollectible accounts. At September 30, 2018, the Registrants’ critical accounting policies and estimates had not changed significantly from December 31, 2017.

Results of Operations by Registrant

Net Income Attributable to Common Shareholders by Registrant

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Exelon	$733	$823	$ (90)	$1,858	$1,907	$ (49)
Generation	234	304	(70)	547	487	60
ComEd	193	189	4	523	447	76
PECO	126	112	14	336	327	9
BGE	63	62	1	242	231	11
PHI	187	153	34	336	359	(23)
Pepco	89	87	2	174	188	(14)
DPL	33	31	2	90	107	(17)
ACE	61	41	20	76	77	(1)

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Results of Operations — Generation

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017	Favorable (Unfavorable) Variance
Operating revenues	$5,278	$4,750	$ 528	$15,368	$13,843	$ 1,525
Purchased power and fuel expense	2,980	2,331	(649)	8,552	7,286	(1,266)
Revenues net of purchased power and fuel expense[(a)]	2,298	2,419	(121)	6,816	6,557	259
Other operating expenses						
Operating and maintenance	1,370	1,376	6	4,126	4,879	753
Depreciation and amortization	468	410	(58)	1,383	1,046	(337)
Taxes other than income	143	141	(2)	414	425	11
Total other operating expenses	1,981	1,927	(54)	5,923	6,350	427
(Loss) gain on sales of assets and businesses	(6)	(2)	(4)	48	3	45
Bargain purchase gain	—	7	(7)	—	233	(233)
Operating income	311	497	(186)	941	443	498
Other income and (deductions)						
Interest expense, net	(101)	(113)	12	(305)	(342)	37
Other, net	179	209	(30)	164	648	(484)
Total other income and (deductions)	78	96	(18)	(141)	306	(447)
Income before income taxes	389	593	(204)	800	749	51
Income taxes	78	239	161	110	215	105
Equity in losses of unconsolidated affiliates	(11)	(8)	(3)	(23)	(26)	3
Net income	300	346	(46)	667	508	159
Net income attributable to noncontrolling interests	66	42	(24)	120	21	(99)
Net income attributable to membership interest	$234	$304	$ (70)	$547	$487	$ 60

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. Generation's Net income attributable to membership interest for the three months ended September 30, 2018 decreased compared to the same period in 2017, primarily due to lower Revenue net of purchased power and fuel expense, higher Depreciation and amortization expenses, lower Other income, partially offset by lower Operating and maintenance expenses and lower Income taxes. The decrease in Revenue net of purchased power and fuel expense primarily relates to the absence of EGTP

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revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017, lower realized energy prices, lower energy efficiency revenues, decreased revenues related to the sale of Generation's electrical contracting business in 2018 and increased nuclear outage days, partially offset by the impact of the Illinois ZES and increased capacity prices. The decrease in Operating and maintenance expenses is primarily due to charges to earnings related to the impairment of the EGTP assets held for sale in 2017, decreased costs related to the sale of Generation's electrical contracting business in 2018 and decreased spending related to energy efficiency projects, partially offset by a charge associated with a remeasurement of the Oyster Creek ARO. The increase in Depreciation and amortization is primarily due to accelerated depreciation and amortization expenses associated with Generation's decision to early retire the Oyster Creek and TMI nuclear facilities. The decrease in Other income is primarily due to the change in realized and unrealized gains and losses on NDT funds. The decrease in Income taxes is primarily due to tax savings related to the TCJA.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. Generation's Net income attributable to membership interest for the nine months ended September 30, 2018 increased compared to the same period in 2017, primarily due to higher Revenue net of purchased power and fuel expense, lower Operating and maintenance expenses and lower Income taxes, partially offset by higher Depreciation and amortization expenses, a Bargain purchase gain in 2017 and lower Other income. The increase in Revenue net of purchased power and fuel expense primarily relates to the impacts of the New York CES and Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), increased capacity prices, the acquisition of the FitzPatrick nuclear facility, decreased nuclear outage days, the addition of two combined-cycle gas turbines in Texas and the impacts of Generation's natural gas portfolio, partially offset by lower realized energy prices, the absence of EGTP revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017, lower energy efficiency revenues and decreased revenues related to the sale of Generation's electrical contracting business in 2018. The decrease in Operating and maintenance is primarily due to the impairment of EGTP assets held for sale in 2017, decreased nuclear outage days in 2018, the impact of a supplemental NEIL distribution, certain costs associated with mergers and acquisitions related to the PHI and FitzPatrick acquisitions, decreased costs related to the sale of Generation's electrical contracting business in 2018 and decreased spending related to energy efficiency projects, partially offset by one-time charges associated with Generation's decision to early retire the TMI and Oyster Creek nuclear facilities. The increase in Depreciation and amortization is primarily due to accelerated depreciation and amortization expenses associated with Generation's decision to early retire the Oyster Creek and TMI nuclear facilities. The Bargain purchase gain in 2017 is due to the acquisition of the FitzPatrick nuclear facility. The decrease in Other income is primarily due to the change in unrealized gains and losses on NDT funds.

Revenues Net of Purchased Power and Fuel Expense

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota,

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South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.

- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions:
- South represents operations in the FRCC, MISO’s Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation’s South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.
Generation evaluates the operating performance of its electric business activities using the measure of Revenue net of purchased power and fuel expense, which is a non-GAAP measurement. Generation’s operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

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For the three and nine months ended September 30, 2018 and 2017, Generation's Revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended September 30,		Variance	% Change	Nine Months Ended September 30,		Variance	% Change
	2018	2017			2018	2017		
Mid-Atlantic[a]	$763	$855	$ (92)	(10.8)%	$2,348	$2,411	$ (63)	(2.6)%
Midwest[b]	768	697	71	10.2 %	2,400	2,140	260	12.1 %
New England	81	145	(64)	(44.1)%	298	403	(105)	(26.1)%
New York[d]	292	295	(3)	(1.0)%	841	707	134	19.0 %
ERCOT	98	118	(20)	(16.9)%	216	258	(42)	(16.3)%
Other Power Regions	99	68	31	45.6 %	309	220	89	40.5 %
Total electric revenue net of purchased power and fuel expense	2,101	2,178	(77)	(3.5)%	6,412	6,139	273	4.4 %
Proprietary Trading	5	4	1	25.0 %	39	11	28	254.5 %
Mark-to-market gains (losses)	71	73	(2)	(2.7)%	(104)	(161)	57	(35.4)%
Other[c]	121	164	(43)	(26.2)%	469	568	(99)	(17.4)%
Total revenue net of purchased power and fuel expense	$2,298	$2,419	$ (121)	(5.0)%	$6,816	$6,557	$ 259	3.9 %

(a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with Pepco, DPL and ACE are included in the Mid-Atlantic region.

(b) Results of transactions with ComEd are included in the Midwest region.

(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes amortization of intangible assets related to commodity contracts recorded at fair value of a $19 million decrease to revenue net of purchased power and fuel expense for the three months ended September 30, 2017, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements of a $18 million decrease and $6 million decrease to revenue net of purchased power and fuel expense for the three months ended September 30, 2018 and 2017, respectively. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of a $41 million decrease to revenue net of purchased power and fuel expense for the nine months ended September 30, 2017, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements of a $53 million decrease and $8 million decrease to revenue net of purchased power and fuel expense for the nine months ended September 30, 2018 and 2017, respectively.

(d) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Generation's supply sources by region are summarized below:

Supply source (GWhs)	Three Months Ended September 30, 2018	2017	Variance	% Change	Nine Months Ended September 30, 2018	2017	Variance	% Change
Nuclear Generation								
Mid-Atlantic[a]	16,197	16,480	(283)	(1.7)%	48,924	48,271	653	1.4%
Midwest	23,834	24,362	(528)	(2.2)%	70,532	69,422	1,110	1.6%
New York[a][c]	6,518	6,905	(387)	(5.6)%	19,758	17,623	2,135	12.1%
Total Nuclear Generation	46,549	47,747	(1,198)	(2.5)%	139,214	135,316	3,898	2.9%
Fossil and Renewables								
Mid-Atlantic	853	596	257	43.1%	2,660	2,330	330	14.2%
Midwest	244	218	26	11.9%	1,020	1,053	(33)	(3.1)%
New England	1,339	1,919	(580)	(30.2)%	4,189	5,921	(1,732)	(29.3)%
New York	1	1	—	—%	3	3	—	—%
ERCOT	3,137	5,703	(2,566)	(45.0)%	8,389	9,388	(999)	(10.6)%
Other Power Regions	2,289	2,149	140	6.5%	6,503	5,656	847	15.0%
Total Fossil and Renewables	7,863	10,586	(2,723)	(25.7)%	22,764	24,351	(1,587)	(6.5)%
Purchased Power								
Mid-Atlantic	3,504	2,541	963	37.9%	4,828	8,840	(4,012)	(45.4)%
Midwest	174	217	(43)	(19.8)%	733	1,018	(285)	(28.0)%
New England	7,217	4,513	2,704	59.9%	18,607	13,920	4,687	33.7%
New York	—	—	—	—%	—	28	(28)	(100.0)%
ERCOT	1,811	1,199	612	51.0%	5,504	5,724	(220)	(3.8)%
Other Power Regions	5,488	3,982	1,506	37.8%	14,124	10,357	3,767	36.4%
Total Purchased Power	18,194	12,452	5,742	46.1%	43,796	39,887	3,909	9.8%
Total Supply/Sales by Region								
Mid-Atlantic[b]	20,554	19,617	937	4.8%	56,412	59,441	(3,029)	(5.1)%
Midwest[b]	24,252	24,797	(545)	(2.2)%	72,285	71,493	792	1.1%
New England	8,556	6,432	2,124	33.0%	22,796	19,841	2,955	14.9%
New York	6,519	6,906	(387)	(5.6)%	19,761	17,654	2,107	11.9%
ERCOT	4,948	6,902	(1,954)	(28.3)%	13,893	15,112	(1,219)	(8.1)%
Other Power Regions	7,777	6,131	1,646	26.8%	20,627	16,013	4,614	28.8%
Total Supply/Sales by Region	72,606	70,785	1,821	2.6%	205,774	199,554	6,220	3.1%

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).
(b) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region, affiliate sales to ComEd in the Midwest region and affiliate sales to Pepco, DPL and ACE in the Mid-Atlantic region.
(c) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Mid-Atlantic

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $92 million decrease in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices, partially offset by increased capacity prices.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $63 million decrease in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices, partially offset by increased capacity prices and decreased nuclear outage days.

Midwest

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $71 million increase in Revenue net of purchased power and fuel expense in the Midwest was primarily due to the impact of the Illinois ZES and increased capacity prices, partially offset by increased nuclear outage days.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $260 million increase in Revenue net of purchased power and fuel expense in the Midwest was primarily due to the impact of the Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), increased capacity prices, and decreased nuclear outage days, partially offset by lower realized energy prices.

New England

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $64 million decrease in Revenue net of purchased power and fuel expense in New England primarily reflects lower realized energy prices and decreased capacity prices.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $105 million decrease in Revenue net of purchased power and fuel expense in New England primarily reflects lower realized energy prices, partially offset by increased capacity prices.

New York

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $3 million decrease in Revenue net of purchased power and fuel expense in New York was primarily due to increased nuclear outage days and the resulting decreased ZEC revenues related to New York CES, partially offset by higher realized energy prices and increased capacity prices.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $134 million increase in Revenue net of purchased power and fuel expense in New York was primarily due to the impact of the New York CES and the acquisition of FitzPatrick, partially offset by the conclusion of the Ginna Reliability Support Service Agreement in Q1 2017.

ERCOT

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $20 million decrease in Revenue net of purchased power and fuel expense in ERCOT was primarily due to the deconsolidation of EGTP in 2017, partially offset by higher realized energy prices and the addition of two combined-cycle gas turbines in Texas.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $42 million decrease in Revenue net of purchased power and fuel expense in ERCOT was

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primarily due to the deconsolidation of EGTP in 2017, partially offset by the addition of two combined-cycle gas turbines in Texas and higher realized energy prices.

Other Power Regions

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $31 million increase in Revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $89 million increase in Revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Proprietary Trading

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $1 million increase in Revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $28 million increase in Revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Mark-to-market

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. Mark-to-market gains on economic hedging activities were $71 million for the three months ended September 30, 2018 compared to gains of $73 million for the three months ended September 30, 2017. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on gains and losses associated with mark-to-market derivatives.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. Mark-to-market losses on economic hedging activities were $104 million for the nine months ended September 30, 2018 compared to losses of $161 million for the nine months ended September 30, 2017. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $43 million decrease in Revenue net of purchased power and fuel expense in Other was due to the decline in revenues related to the energy efficiency business, the sale of Generation's electrical contracting business in 2018, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements, partially offset by the absence of amortization of energy contracts recorded at fair value associated with prior acquisitions.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $99 million decrease in Revenue net of purchased power and fuel expense in Other was due to the decline in revenues related to the energy efficiency business, the sale of Generation's electrical contracting business in 2018, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements, partially offset by Generation's higher natural gas portfolio

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optimization and the absence of amortization of energy contracts recorded at fair value associated with prior acquisitions.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for the three and nine months ended September 30, 2018 compared to the same period in 2017 for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Nuclear fleet capacity factor[(a)]	93.6%	96.1%	94.4%	93.7%
Refueling outage days[(a)]	36	13	198	233
Non-refueling outage days[(a)]	12	15	20	35

(a) Reflects ownership percentage of stations operated by Exelon. Excludes Salem, which is operated by PSEG Nuclear, LLC. Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Operating and Maintenance Expense

The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018 as compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)[a]	Nine Months Ended September 30, 2018 Increase (Decrease)[a]
Labor, other benefits, contracting, materials[b]	$ (50)	$ (163)
Nuclear refueling outage costs, including the co-owned Salem plants[c]	40	(56)
Insurance[d]	(2)	(38)
Merger and integration costs[e]	(11)	(66)
Plant retirements and divestitures[f]	90	47
Change in environmental liabilities	(12)	(5)
Long-lived asset impairments[g]	(33)	(411)
Pension and non-pension postretirement benefits expense	(7)	(18)
Allowance for uncollectible accounts	(3)	(13)
Other	(18)	(30)
Decrease in Operating and maintenance expense	$ (6)	$ (753)

(a) The financial results include Generation's acquisition of the FitzPatrick nuclear generating station from March 31, 2017.

(b) Primarily reflects decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business in 2018.

(c) Primarily reflects an increase in the number of nuclear outage days for the three months ended September 30, 2018 compared to the same period in 2017 and a decrease in the number of nuclear outage days for the nine months ended September 30, 2018 compared to the same period in 2017.

(d) Primarily reflects the impact of a supplemental NEIL insurance distribution.

(e) Primarily reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI and FitzPatrick acquisitions in 2017, and the PHI acquisition in 2018.

(f) Primarily reflects one-time charges associated with Generation’s decision to early retire the Oyster Creek nuclear facility including ARO in 2018 and the TMI nuclear facility in 2017.

(g) Primarily reflects charges to earnings related to the impairment of the EGTP assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.

Depreciation and Amortization Expense

Depreciation and amortization expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 increased primarily due to accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include non-income municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

(Loss) gain on Sales of Assets and Businesses

Loss on sales of assets and businesses for the three months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent. Gain on sales of assets and businesses for the nine months ended September 30, 2018 compared to the same period in 2017 increased primarily due to Generation's 2018 sale of its electrical contracting business.

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Bargain Purchase Gain

Bargain purchase gain for the three and nine months ended September 30, 2018 compared to the same period in 2017 decreased as a result of the gain associated with the FitzPatrick acquisition in 2017. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2018 compared to the same period in 2017 primarily reflects decreased interest expense due to the retirement of long-term debt.

Other, Net

Other, net for the three and nine months ended September 30, 2018 compared to the same period in 2017 decreased primarily due to the change in the realized and unrealized gains and losses related to NDT funds of Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $29 million and $37 million for the three months ended September 30, 2018 and 2017, respectively, and $24 million and $129 million for the nine months ended September 30, 2018 and 2017, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units. See Note 13 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

The following table provides unrealized and realized gains and losses on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net unrealized gains (losses) on decommissioning trust funds	$72	$111	$(143)	$347
Net realized gains on sale of decommissioning trust funds	29	33	164	82

Equity in Losses of Unconsolidated Affiliates

Equity in losses of unconsolidated affiliates for the three and nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Effective Income Tax Rate

Generation's effective income tax rate was 20.1% and 40.3% for the three months ended September 30, 2018 and 2017, respectively. Generation's effective income tax rate was 13.8% and 28.7% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2018 compared to the same periods in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information of the change in the effective income tax rate.

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Results of Operations — ComEd

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017	Favorable (Unfavorable) Variance
Operating revenues	$1,598	$1,571	$ 27	$4,508	$4,227	$ 281
Purchased power expense	619	529	(90)	1,702	1,241	(461)
Revenues net of purchased power expense[(a)(b)]	979	1,042	(63)	2,806	2,986	(180)
Other operating expenses						
Operating and maintenance	337	346	9	974	1,096	122
Depreciation and amortization	237	212	(25)	696	631	(65)
Taxes other than income	82	80	(2)	238	223	(15)
Total other operating expenses	656	638	(18)	1,908	1,950	42
Gain on sales of assets	—	—	—	5	—	5
Operating income	323	404	(81)	903	1,036	(133)
Other income and (deductions)						
Interest expense, net	(85)	(89)	4	(261)	(275)	14
Other, net	7	5	2	21	14	7
Total other income and (deductions)	(78)	(84)	6	(240)	(261)	21
Income before income taxes	245	320	(75)	663	775	(112)
Income taxes	52	131	79	140	328	188
Net income	$193	$189	$ 4	$523	$447	$ 76

(a) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. ComEd's Net income for the three months ended September 30, 2018 was higher than the same period in 2017 primarily due to higher electric distribution and energy efficiency formula rate earnings. The TCJA did not significantly impact ComEd's net income for the three months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. ComEd's Net income for the nine months ended September 30, 2018 was higher than the same period in 2017 primarily due to higher electric distribution and energy efficiency formula rate earnings as well as additional tax and interest recorded in the second quarter of 2017 relating to Exelon's like-kind exchange tax position. The TCJA did not significantly impact ComEd's net income for the nine

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months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Revenues Net of Purchased Power Expense

There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity, REC, and ZEC procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity, REC, and ZEC procurement costs from retail customers without mark-up. Therefore, fluctuations in these costs have no impact on Revenue net of purchased power expense. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries but do affect ComEd's Operating revenues related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and nine months ended September 30, 2018 and 2017, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	67 %	68 %	68 %	70 %

Retail customers purchasing electric generation from competitive electric generation suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	1,367,700	34 %	1,360,800	34 %

The changes in ComEd's Revenue net of purchased power expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Electric distribution revenue	$ (59)	$ (126)
Transmission revenue	(16)	(32)
Energy efficiency revenue[(a)]	14	31
Regulatory required programs[(a)]	(1)	(95)
Uncollectible accounts recovery, net	2	5
Other	(3)	37
Total decrease	$ (63)	$ (180)

(a) Beginning on June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

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Revenue Decoupling. The demand for electricity is affected by weather conditions. Under FEJA, ComEd revised its electric distribution rate formula effective January 1, 2017 to eliminate the favorable and unfavorable impacts on Operating revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in ComEd's service territory with cooling degree-days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree-days in ComEd's service territory for the three and nine months ended September 30, 2018 and 2017, consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	56	42	97	33.3%	(42.3)%
Cooling Degree-Days	895	699	641	28.0%	39.6 %
Nine Months Ended September 30,					
Heating Degree-Days	3,993	3,269	3,972	22.1%	0.5 %
Cooling Degree-Days	1,259	962	882	30.9%	42.7 %

Electric Distribution Revenue. EIMA and FEJA provide for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. In addition, ComEd's allowed ROE is subject to reduction if ComEd does not deliver the reliability and customer service benefits to which it has committed over the ten-year life of the investment program. Electric distribution revenue decreased during the three and nine months ended September 30, 2018, primarily due to the impact of the lower federal income tax rate, partially offset by increased revenues due to higher rate base and increased depreciation expense as compared to the same period in 2017. See Depreciation and amortization expense discussions below and Note 6 — Regulatory Matters and Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. For the three months ended September 30, 2018, ComEd recorded decreased transmission revenue primarily due to the impact of the lower federal income tax rate, partially offset by increased revenues due to higher rate base and increased depreciation expense as compared to the same period in 2017. For the nine months ended September 30, 2018, ComEd recorded decreased transmission revenue primarily due to the decreased peak load and the impact of the lower federal income tax rate, partially offset by increased revenues due to higher rate base and increased depreciation expense as compared to the same period in 2017. See Operating and maintenance expense below and Note 6 — Regulatory Matters and Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Revenue. Beginning June 1, 2017, FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual

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costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. Beginning January 1, 2018, ComEd's allowed ROE is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. See Depreciation and amortization expense discussions below and Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved rate riders to recover costs incurred for regulatory programs such as ComEd's purchased power administrative costs and energy efficiency and demand response through June 1, 2017 pursuant to FEJA. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Uncollectible accounts recovery, net represents recoveries under ComEd's uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs. The increase in Other revenue for the nine months ended September 30, 2018 compared to the same period in 2017 primarily reflects mutual assistance revenues associated with hurricane and winter storm restoration efforts. An equal and offsetting amount has been included in Operating and maintenance expense and Taxes other than income.

Operating and Maintenance Expense

	Three Months Ended September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense — baseline	$336	$344	$ (8)	$973	$1,000	$ (27)
Operating and maintenance expense — regulatory required programs[(a)]	1	2	$ (1)	1	96	(95)
Total Operating and maintenance expense	$337	$346	$ (9)	$974	$1,096	$ (122)

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The decrease in Operating and maintenance expense for the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials[a]	$ (1)	$ (3)
Pension and non-pension postretirement benefits expense[a]	(1)	(1)
Storm-related costs	(5)	(21)
Uncollectible accounts expense — provision[b]	7	11
Uncollectible accounts expense — recovery, net[b]	(5)	(6)
BSC costs[a]	(9)	(8)
Other[a]	6	1
	(8)	(27)
Regulatory required programs		
Energy efficiency and demand response programs[c]	(1)	(95)
Decrease in operating and maintenance expense	$ (9)	$ (122)

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(b) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. During the three and nine months ended September 30, 2018, ComEd recorded a net increase in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(c) Beginning June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

Depreciation and Amortization Expense

The increase in Depreciation and amortization expense during the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase	Nine Months Ended September 30, 2018 Increase
Depreciation expense[a]	$ 9	$ 30
Regulatory asset amortization[b]	16	35
Total increase	$ 25	$ 65

(a) Primarily reflects ongoing capital expenditures for the three and nine months ended September 30, 2018.

(b) Beginning in June 2017, includes amortization of ComEd's energy efficiency formula rate regulatory asset.

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes and payroll taxes.

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Gain on Sales of Assets
The increase in Gain on sales of assets during the nine months ended September 30, 2018 compared to the same period in 2017, is primarily due to the sale of land in March 2018.
Interest Expense, Net
The changes in Interest expense, net, for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Interest expense related to uncertain tax positions[(a)]	$ —	$ (13)
Interest expense on debt (including financing trusts)	(2)	2
Other	(2)	(3)
Total decrease	$ (4)	$ (14)

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(a) Primarily reflects additional interest recorded in the second quarter of 2017 related to Exelon's like-kind exchange tax position.
Other, Net
Other, net, remained relatively consistent for the three and nine months ended September 30, 2018 compared to the same period in 2017.
Effective Income Tax Rate
ComEd's effective income tax rate was 21.2% and 40.9% for the three months ended September 30, 2018 and 2017, respectively. ComEd's effective income tax rate was 21.1% and 42.3% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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ComEd Electric Operating Statistics Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2018	2017	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather-Normal % Change
Retail Deliveries[(a)]								
Residential	8,845	8,004	10.5 %	(1.5)%	22,019	20,164	9.2 %	0.1 %
Small commercial & industrial	8,626	8,488	1.6 %	(1.0)%	24,204	23,634	2.4 %	— %
Large commercial & industrial	7,450	7,232	3.0 %	1.1 %	21,398	20,712	3.3 %	1.6 %
Public authorities & electric railroads	301	302	(0.3)%	(0.5)%	947	928	2.0 %	1.2 %
Total retail deliveries	25,222	24,026	5.0 %	(0.5)%	68,568	65,438	4.8 %	0.6 %

Number of Electric Customers	As of September 30, 2018	2017
Residential	3,635,678	3,610,091
Small commercial & industrial	380,529	376,309
Large commercial & industrial	1,994	1,954
Public authorities & electric railroads	4,767	4,763
Total	4,022,968	3,993,117

(a) Reflects delivery volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

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Results of Operations — PECO

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Operating revenues	$757	$715	$ 42	$2,275	$2,141	$ 134
Purchased power and fuel expense	263	235	(28)	818	719	(99)
Revenues net of purchased power and fuel expense[(a)]	494	480	14	1,457	1,422	35
Other operating expenses						
Operating and maintenance	219	197	(22)	686	595	(91)
Depreciation and amortization	75	72	(3)	224	213	(11)
Taxes other than income	46	42	(4)	125	116	(9)
Total other operating expenses	340	311	(29)	1,035	924	(111)
Gain on sales of assets	—	—	—	1	—	1
Operating income	154	169	(15)	423	498	(75)
Other income and (deductions)						
Interest expense, net	(32)	(31)	(1)	(96)	(93)	(3)
Other, net	2	2	—	4	6	(2)
Total other income and (deductions)	(30)	(29)	(1)	(92)	(87)	(5)
Income before income taxes	124	140	(16)	331	411	(80)
Income taxes	(2)	28	30	(5)	84	89
Net income	$126	$112	$ 14	$336	$327	$ 9

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not presentations defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. PECO's Net income increased from the same period in 2017, primarily due to higher Operating revenues net of purchase power and fuel expense attributable to favorable weather and volume. The TCJA did not significantly impact PECO's Net income for the three and nine months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the requirement to pass back the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. PECO's Net income increased from the same period in 2017, primarily due to higher Operating revenues net of purchase power and fuel expense attributable to favorable weather and volume, partially offset by higher Operating and maintenance expense attributable to increased storm restoration costs as a result of winter storms in March 2018. The TCJA did not significantly impact PECO's Net income for the three and nine months ended September 30, 2018 as the favorable income tax impacts were

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predominantly offset by lower revenues resulting from the requirement to pass back the tax savings through customer rates.

Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with PECO's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenue net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customer's Choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and natural gas revenues net of purchased power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2018 and 2017, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	68 %	70 %	69 %	71 %
Natural Gas	31 %	29 %	26 %	26 %

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	536,000	33 %	570,500	35 %
Natural Gas	88,900	17 %	82,600	16 %

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The changes in PECO’s Operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)			Nine Months Ended September 30, 2018 Increase (Decrease)		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Weather	$20	$ 1	$21	$39	$ 19	$58
Volume	17	(1)	16	26	2	28
Pricing	(36)	3	(33)	(66)	(5)	(71)
Regulatory required programs	7	—	7	5	—	5
Other	3	—	3	18	(3)	15
Total increase	$11	$ 3	$14	$22	$ 13	$35

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three and nine months ended September 30, 2018 compared to the same period in 2017, Operating revenue net of purchased power and fuel increased due to favorable weather conditions.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in PECO's service territory. The changes in heating and cooling degree-days in PECO’s service territory for the three and nine months ended September 30, 2018 compared to the same period in 2017 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2018	2017	Normal	From 2017	2018 vs. Normal
Heating Degree-Days	13	14	27	(7.1)%	(51.9)%
Cooling Degree-Days	1,124	989	999	13.7 %	12.5 %
Nine Months Ended September 30,					
Heating Degree-Days	2,892	2,437	2,912	18.7 %	(0.7)%
Cooling Degree-Days	1,506	1,404	1,383	7.3 %	8.9 %

Volume. Operating revenue net of purchased power related to delivery volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2018 compared to the same period in 2017, increased due to the impact of moderate economic and customer growth partially offset by the impact of energy efficiency initiatives on customer usages primarily in the residential class. Additionally, the increase represents a shift in the volume profile across classes from the commercial and industrial classes to the residential class.

Pricing. Operating revenues net of purchased power as a result of pricing for the three and nine months ended September 30, 2018 and operating revenues net of fuel as the result of pricing for the nine months ended September 30, 2018 compared to the same periods in 2017 decreased primarily due to the pass back through customers rates the tax savings associated with the lower federal income

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tax rate. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. See Operating and maintenance expense discussion below for additional information on included programs.

Other. Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.

Operating and Maintenance Expense

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Increase (Decrease)	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017	Increase (Decrease)
Operating and maintenance expense — baseline	$198	$183	$ 15	$632	$552	$ 80
Operating and maintenance expense — regulatory required programs[(a)]	21	14	7	54	43	11
Total Operating and maintenance expense	$219	$197	$ 22	$686	$595	$ 91

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ (1)	$ 10
Storm-related costs[(a)]	2	61
Pension and non-pension postretirement benefits expense	(2)	(5)
Uncollectible accounts expense	6	8
Other	10	6
	15	80
Regulatory Required Programs		
Energy efficiency	7	11
Total increase	$ 22	$ 91

(a) Reflects increased costs incurred from the Q1 2018 winter storms.

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Depreciation and Amortization Expense

Depreciation and amortization expense increased primarily due to ongoing capital spend for the three and nine months ended September 30, 2018 compared to the same period in 2017.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income increased for the three and nine months ended September 30, 2018 compared to the same period in 2017 due to an increase in gross receipts tax driven by an increase in electric revenue.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2018 remained relatively consistent compared to the same period in 2017.

Other, Net

Other, net for the three and nine months ended September 30, 2018 remained consistent compared to the same period in 2017.

Effective Income Tax Rate

PECO's effective income tax rate was (1.6)% and 20.0% for the three months ended September 30, 2018 and 2017, respectively. PECO's effective income tax rate was (1.5)% and 20.4% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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PECO Electric Operating Statistics

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	4,166	3,752	11.0 %	4.7 %	10,741	9,939	8.1 %	2.8 %
Small commercial & industrial	2,315	2,158	7.3 %	2.0 %	6,273	6,048	3.7 %	0.4 %
Large commercial & industrial	4,378	4,137	5.8 %	4.9 %	11,892	11,593	2.6 %	2.5 %
Public authorities & electric railroads	189	198	(4.5)%	(4.8)%	568	618	(8.1)%	(7.7)%
Total retail deliveries	11,048	10,245	7.8 %	4.0 %	29,474	28,198	4.5 %	1.9 %

Number of Electric Customers	As of September 30, 2018	2017
Residential	1,476,914	1,463,906
Small commercial & industrial	152,253	150,964
Large commercial & industrial	3,124	3,112
Public authorities & electric railroads	9,561	9,665
Total	1,641,852	1,627,647

(a) Reflects delivery volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

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PECO Natural Gas Operating Statistics

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	2,099	2,177	(3.6)%	0.9%	28,562	24,866	14.9%	0.2%
Small commercial & industrial	1,776	1,814	(2.1)%	0.2%	15,792	13,944	13.3%	1.0%
Large commercial & industrial	6	2	200.0%	12.8%	58	15	286.7%	278.3%
Transportation	5,693	5,674	0.3%	3.2%	19,242	19,122	0.6%	(3.8)%
Total natural gas deliveries	9,574	9,667	(1.0)%	1.6%	63,654	57,947	9.8%	(0.8)%

Number of Natural Gas Customers	As of September 30, 2018	2017
Residential	479,732	474,766
Small commercial & industrial	43,638	43,352
Large commercial & industrial	1	6
Transportation	761	771
Total	524,132	518,895

(a) Reflects delivery volumes from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

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Results of Operations — BGE

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Operating revenues	$731	$738	$ (7)	$2,369	$2,363	$ 6
Purchased power and fuel expense	272	269	(3)	881	853	(28)
Revenues net of purchased power and fuel expense[(a)]	459	469	(10)	1,488	1,510	(22)
Other operating expenses						
Operating and maintenance	182	175	(7)	578	532	(46)
Depreciation and amortization	110	109	(1)	358	348	(10)
Taxes other than income	64	61	(3)	188	180	(8)
Total other operating expenses	356	345	(11)	1,124	1,060	(64)
Gain on sales of assets	—	—	—	1	—	1
Operating income	103	124	(21)	365	450	(85)
Other income and (deductions)						
Interest expense, net	(27)	(26)	(1)	(78)	(80)	2
Other, net	5	4	1	14	12	2
Total other income and (deductions)	(22)	(22)	—	(64)	(68)	4
Income before income taxes	81	102	(21)	301	382	(81)
Income taxes	18	40	22	59	151	92
Net income	$63	$62	$ 1	$242	$231	$ 11

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies’ presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. BGE’s Net income for the three months ended September 30, 2018 was relatively consistent with the same period in 2017. The TCJA did not significantly impact BGE's net income for the three months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. BGE’s Net income for the nine months ended September 30, 2018 was higher than the same period in 2017, due primarily to higher transmission revenues, partially offset by an increase in Operating and maintenance expense attributable to increased storm restoration costs as a result of storms in March 2018 and September 2018. The TCJA did not significantly impact BGE's net income for the nine months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

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Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenues that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Operating revenues and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE’s electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC’s market-based SOS and gas commodity programs, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on Revenues net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive supplier for electricity and/or natural gas. All BGE customers have the choice to purchase electricity and natural gas from competitive suppliers. The customers' choice of suppliers does not impact the volume of deliveries but does affect revenue collected from customers related to supplied electricity and natural gas.

Retail deliveries purchased from competitive electricity and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2018 and 2017 consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	59%	60%	59%	60%
Natural Gas	76%	74%	56%	57%

The number of retail customers purchasing electricity and natural gas from competitive suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	335,200	26 %	339,300	27 %
Natural Gas	147,400	22 %	148,600	22 %

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The changes in BGE’s Operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018			Nine Months Ended September 30, 2018		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution revenue	$(17)	$(2)	$(19)	$(48)	$(19)	$(67)
Regulatory required programs	1	(1)	—	3	2	5
Transmission revenue	6	—	6	23	—	23
Other, net	—	3	3	6	11	17
Total decrease	$(10)	$—	$(10)	$(16)	$(6)	$(22)

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of fluctuations in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved distribution charges per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth (i.e., increase in the number of customers), it will not be affected by volatility in actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in BGE's service territory. The changes in heating and cooling degree-days in BGE's service territory for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	31	64	76	(51.6)%	(59.2)%
Cooling Degree-Days	733	595	601	23.2 %	22.0 %
Nine Months Ended September 30,					
Heating Degree-Days	2,969	2,524	2,974	17.6 %	(0.2)%
Cooling Degree-Days	1,032	877	857	17.7 %	20.4 %

Distribution Revenue. The decrease in distribution revenues for the three and nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to the impact of reduced distribution rates to reflect the lower federal income tax rate. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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Regulatory Required Programs. Revenue from regulatory required programs are billings for the costs of various legislative and/or regulatory programs that are recoverable from customers on a full and current basis. These programs are designed to provide full cost recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE's Consolidated Statements of Operations and Comprehensive Income.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon rate adjustments to reflect fluctuations in the underlying costs, capital investments being recovered and other billing determinants. The increase in transmission revenue for the three and nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net. Other, net revenue, which can vary from period to period, primarily includes assistance provided to other utilities through BGE's mutual assistance program, service application fees, and other miscellaneous revenue such as off-system sales and administrative charges.

Operating and Maintenance Expense

	Three Months Ended September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense — baseline	$180	$172	$ 8	$572	$520	$ 52
Operating and maintenance expense — regulatory required programs (a)	2	3	(1)	6	12	(6)
Total Operating and maintenance expense	$182	$175	$ 7	$578	$532	$ 46

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
Storm-related costs[(a)]	$ 5	$ 36
Labor, other benefits, contracting and materials	1	2
Uncollectible accounts expense	1	3
BSC costs	(1)	4
Other	2	7
	8	52
Regulatory Required Programs		
Other	(1)	(6)
Total increase	$ 7	$ 46

(a) Reflects increased storm restoration costs incurred from storms in Q1 2018 and Q3 2018.

Depreciation and Amortization

The changes in Depreciation and amortization expense for the three and nine months ended September 30, 2018, compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 8	$ 17
Regulatory asset amortization[(b)]	(8)	(18)
Regulatory required programs[(c)]	1	11
Total increase	$ 1	$ 10

(a) Depreciation expense increased due to ongoing capital expenditures.

(b) Regulatory asset amortization decreased for the three and nine months ended September 30, 2018 compared to the same period in 2017 primarily due to certain regulatory assets that became fully amortized as of December 31, 2017. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(c) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and nine months ended September 30, 2018, compared to the same period in 2017, increased primarily due to an increase in property taxes.

Gain on Sales of Assets

Gain on sales of assets, for the three months ended September 30, 2018 compared to the same period in 2017, remained relatively consistent. The increase in Gain on sales of assets during the nine

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months ended September 30, 2018, compared to the same period in 2017, is due to the sale of land in June 2018.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2018, compared to the same period in 2017, remained relatively consistent.

Other, Net

Other, net for the three and nine months ended September 30, 2018, compared to the same period in 2017, remained relatively consistent.

Effective Income Tax Rate

BGE’s effective income tax rate was 22.2% and 39.2% for the three months ended September 30, 2018 and 2017, respectively. BGE's effective income tax rate was 19.6% and 39.5% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2018, compared to the same periods in 2017, is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30,	% Change