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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

January 28, 2022

Date of Report (Date of earliest event reported)

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
001-41137	CONSTELLATION ENERGY CORPORATION (a Pennsylvania corporation) 1310 Point Street Baltimore, Maryland 21231 (800) 483-3220	87-1210716

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
CONSTELLATION ENERGY CORPORATION		
Common Stock, without par value	CEG	The Nasdaq Stock Market LLC

Indicate by check mark whether any of the registrants are emerging growth companies as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter). Emerging growth company ☐

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

Item 8.01. Other Events.

Constellation Energy Corporation ("Constellation") previously filed with the Securities and Exchange Commission (the "Commission") Amendment Number 2 to its General Form for Registration of Securities on Form 10, which was filed with the Commission on December 20, 2021, and declared effective by the Commission on December 29, 2021 (as amended, the "Registration Statement"), relating to the distribution by Exelon Corporation ("Exelon") of all of the outstanding shares of common stock, no par value, of Constellation to Exelon's shareholders (the "Distribution"). The Registration Statement includes an amended preliminary information statement that describes the Distribution and provides important information regarding Constellation's business and management.

The final information statement, dated January 24, 2022, is attached to this Current Report on Form 8-K as Exhibit 99.1 and is incorporated herein by reference.

Exelon has made the information statement publicly available on January 28, 2022, and expects to begin mailing to its shareholders an Important Notice Regarding the Availability of Materials as soon as reasonably practicable, the form of which is attached as Exhibit 99.2 to this Current Report on Form 8-K.

Item 9.01. Financial Statements and Exhibits.

(d) Exhibits.

Exhibit No.	Description
99.1	Information Statement of Constellation Energy Corporation, dated January 24, 2022
99.2	Form of Important Notice Regarding the Availability of Materials
104	The cover page from this Current Report on Form 8-K, formatted as Inline XBRL

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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 hereunto duly authorized.

CONSTELLATION ENERGY CORPORATION

/s/ Carter C. Culver

Carter C. Culver
Assistant Secretary
Constellation Energy Corporation

January 28, 2022

CONSTELLATION ENERGY CORPORATION

Information Statement

Distribution of Common Stock of Constellation Energy Corporation
by

EXELON CORPORATION

to

EXELON CORPORATION SHAREHOLDERS

This information statement is being sent to you in connection with the separation of Constellation Energy Corporation (collectively with its consolidated subsidiaries, the "*Company*") from Exelon Corporation ("*Exelon*"). As a result of the separation, Exelon's competitive power generation and customer-facing energy businesses conducted through Exelon Generation Company, LLC ("*Generation*") and its subsidiaries will be owned by the Company, which will be an independent, publicly-traded company. Exelon will complete the separation by distributing all of the outstanding shares of the Company's common stock ("*Company common stock*" or "*our common stock*"), on a pro rata basis to the holders ("*Exelon shareholders*") of Exelon's common stock. We refer to this pro rata distribution as the "*distribution*," and we refer to the separation as the "*separation*".

Each Exelon shareholder will receive one share of our common stock for every three shares of Exelon common stock held by such shareholder on January 20, 2022, the record date. Exelon will not distribute any fractional shares of Company common stock. Instead, the distribution agent will aggregate fractional shares into whole shares, sell the whole shares in the open market at prevailing market prices and distribute the aggregate net cash proceeds from the sales pro rata to each holder who would otherwise have been entitled to receive a fractional share in the separation. The distribution of shares will be made in book-entry form only. The distribution will be effective as of 12:01 a.m., Eastern time, on February 1, 2022. Immediately after the distribution becomes effective, the Company will be an independent, publicly-traded company.

We expect that the distribution will be tax-free to Exelon shareholders for U.S. federal income tax purposes, except to the extent of cash received in lieu of fractional shares. You should consult your own tax advisor as to the particular consequences of the distribution to you, including the applicability and effect of any U.S. federal, state and local and non-U.S. tax laws.

No vote or other action of Exelon shareholders is required in connection with the separation. We are not asking you for a proxy, and Exelon requests that you do not send Exelon a proxy. Exelon shareholders will not be required to pay any consideration for the shares of Company common stock they receive in the distribution, and they will not be required to surrender or exchange their shares of Exelon common stock or to take any other action in connection with the separation.

All outstanding shares of the Company common stock are currently owned by Exelon. Accordingly, there is no current trading market for the Company common stock. We anticipate that a limited market, commonly known as a "when-issued" trading market, will develop shortly before the record date, and that "regular-way" trading in shares of the Company common stock will begin on the first trading day following the distribution date. If trading begins on a "when-issued" basis, you may purchase or sell the Company common stock up to and including the distribution date, in which case your transaction will settle within two trading days after regular-way trading commences following the distribution. We intend to list the Company common stock on the NASDAQ Stock Market, Inc. ("*NASDAQ*") under the ticker symbol "CEG." As discussed below under "Trading Market," if you sell your Exelon common stock in the "regular-way" market before the distribution date, you also will be selling your right to receive shares of the Company common stock in connection with the distribution. However, if you sell your Exelon common stock in the "ex-distribution" market before the distribution date, you will still receive shares of the Company common stock in the distribution.

In reviewing this information statement, you should carefully consider the matters described in "Risk Factors" beginning on page 26 of this information statement.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved these securities or determined if this information statement is truthful or complete. Any representation to the contrary is a criminal offense.

This information statement is not an offer to sell, or a solicitation of an offer to buy, any securities.

The date of this information statement is January 24, 2022.

A Notice of Internet Availability of Information Statement Materials containing instructions describing how to access this information statement was first mailed to Exelon shareholders on or about January 28, 2022.

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Unless otherwise indicated or the context otherwise requires, references in this information statement to the "*Company*," "*we*," "*us*," "*our*," and "*our company*" refer to Constellation Energy Corporation and its consolidated subsidiaries, and references herein to "*Exelon*" refer to Exelon Corporation and its consolidated subsidiaries prior to the completion of the separation.

Each of the Company's and Exelon's affiliated operations is owned and operated by a separate subsidiary that has its own management, employees and assets. References herein to the consolidated "Company," "Exelon," "Parent" or "its" or "our" assets and activities are not meant to imply, nor should they be construed as meaning, that the Company or Exelon has any direct operating assets, employees or revenue, or that any of the subsidiaries are operated by the Company or Exelon.

Unless otherwise indicated or the context otherwise requires, all information in this information statement gives effect to the effectiveness of our amended and restated certificate of incorporation and amended and restated bylaws, the forms of which are filed as exhibits to the registration statement of which this information statement forms a part.

FINANCIAL STATEMENT PRESENTATION

This information statement includes certain historical consolidated financial and other data for Generation and its subsidiaries. Constellation Energy Corporation will become the parent of Generation immediately prior to the separation. Constellation Energy Corporation is the registrant under the registration statement of which this information statement forms a part and will be the financial reporting entity following the consummation of the separation. Generation is presently, and will continue to be, a financial reporting entity following the separation.

This information statement also includes an unaudited pro forma condensed consolidated balance sheet as of September 30, 2021 and unaudited pro forma condensed consolidated statement of operations for the nine months ended September 30, 2021 and the year ended December 31, 2020, which present our consolidated financial position and results of operations after giving effect to the separation and distribution, and the other transactions described under “Unaudited Pro Forma Condensed Consolidated Financial Statements.” The unaudited pro forma condensed consolidated financial statements are presented for illustrative purposes only and are not necessarily indicative of the operating results or financial position that would have occurred if the relevant transactions had been consummated on the date indicated, nor is it indicative of future operating results.

You should read the section titled “Unaudited Pro Forma Condensed Consolidated Financial Statements,” which is qualified in its entirety by reference to the audited consolidated financial statements and related notes thereto and the financial and other information, including in the sections titled “Risk Factors,” “Capitalization” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” in each case included elsewhere in this information statement.

Constellation Energy Corporation was formed on June 15, 2021 in connection with the separation transaction and has engaged in no activity other than incidental to the separation. As of June 15, 2021, it had no assets or liabilities. In connection with the separation transaction, Constellation Energy Corporation. will become the parent of Generation and its subsidiaries, which will constitute all of its assets and business operations.

INDUSTRY AND MARKET DATA

This information statement contains estimates and projections regarding market and industry data that were obtained from internal Company estimates as well as third-party sources, such as market research, consultant surveys, publicly available information and industry publications and surveys. We believe the information provided or made available by these third-party sources is generally reliable. However, market data is subject to change and cannot always be verified with complete certainty due to limits on the availability and reliability of raw data, the voluntary nature of the data-gathering process and other limitations and uncertainties inherent in any statistical survey, interpretation or presentation of market data and management’s estimates and projections. In addition, projections are often wrong. As a result, you should be aware that market data set forth herein, and estimates, projections and beliefs based on that data presented herein, may not be reliable. We have not independently verified any of the data from third-party sources nor have we ascertained the underlying economic assumptions relied upon therein, and we cannot guarantee its accuracy or completeness. Unless identified as a third-party source, market data is based on internal company estimates and data. Similarly, internal company estimates, which we believe to be reliable, are based upon management’s knowledge of the industry as of the date of those estimates and have not been verified by any independent sources. Accordingly, we cannot guarantee the accuracy or completeness of any such information and you should not place undue reliance on that information when making your investment decision.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This information statement and other materials Exelon and we have filed or will file with the SEC (and oral communications that Exelon and we may make) contain or incorporate by reference statements that relate to future events and expectations and, as such, constitute forward-looking statements under the securities laws. Forward-looking statements include those statements containing words such as “anticipates,” “believes,” “could,” “estimates,” “expects,” “forecasts,” “goal,” “guidance,” “intends,” “may,” “outlook,” “plans,” “projects,” “seeks,” “sees,” “should,” “targets,” “will,” “would,” or other words with similar meaning. All statements that reflect Exelon’s or our expectations, assumptions or projections about the future, other than statements of historical fact, are forward-looking statements, including, without limitation, statements and guidance regarding future financial results or operating performance; and statements about Exelon’s or our strategies, outlook, business and financial prospects. Forward-looking statements are not guarantees of future performance and are subject to risks, uncertainties, and changes in circumstances that are difficult to predict. Although each of Exelon and we believe that the expectations reflected in any forward-looking statements it makes are based on reasonable assumptions, no assurance can be given that these expectations will be attained, and it is possible that actual results may differ materially from those indicated by these forward-looking statements due to a variety of risks and uncertainties. Such risks and uncertainties include the following:

- deterioration in global economic and financial market conditions generally;
- unfavorable changes in the markets served by Exelon and us;
- competition from disruptive technologies, industry consolidation or other developments;
- the loss of key customers or significant changes in the business or financial condition of customers;
- political, economic, and regulatory risks relating to Exelon’s and our operations;
- acts of war, terrorism or civil unrest;
- pandemics or other public health crises, and adverse changes in economic and market conditions related to such pandemics or other health crises;
- a material disruption of our operations, particularly at one or more of our nuclear generating facilities;
- the inability to achieve the level of revenue growth, cash generation, cost savings, improvement in profitability and margins, fiscal discipline, or strengthening of competitiveness and operations anticipated or targeted;
- the impact of potential cyber-attacks and information technology or data security breaches;
- the inability to develop innovative new products or implement technology initiatives successfully;
- adverse changes in discount rates or investment returns on pension assets;
- Exelon’s and our inability to realize expected benefits, in each case as planned and by targeted completion dates, from acquisitions, divestitures, facility closures, curtailments, expansions or joint ventures;
- a significant downturn in the business or financial condition of a significant supplier;
- the outcome of contingencies, including legal proceedings, government or regulatory investigations, and environmental compliance and remediation, which can expose Exelon and us to substantial costs and liabilities;
- the expected benefits and timing of the separation, and uncertainties regarding the planned separation, including the risk that conditions to the separation will not be satisfied and that it will not be completed pursuant to the targeted timing, asset perimeters, and other anticipated terms, if at all;
- the impact of the separation on Exelon’s businesses;
- a determination by the IRS that the distribution or certain related transactions should be treated as taxable transactions;

- the possibility that any consents or approvals required in connection with the separation will not be received or obtained within the expected time frame, on the expected terms or at all;
- the risk that dis-synergy costs, costs of restructuring transactions and other costs incurred in connection with the separation will exceed our estimates; and
- the impact of the separation on our businesses and the risk that the businesses will not be separated successfully or such separation may be more difficult, time-consuming or costly than expected, which could result in additional demands on Exelon's resources, systems, procedures and controls, and disruption of our ongoing business, and impact our relationships with customers, suppliers, employees and other business counterparties.

There can be no assurance that the distribution and separation will in fact be consummated in the manner described or at all. The above list of factors is not exhaustive or necessarily in order of importance. For additional information on identifying factors that may cause actual results to vary materially from those stated in forward-looking statements, see the discussions under "Risk Factors" in this information statement. Any forward-looking statement speaks only as of the date on which it is made, and each of Exelon and we assume no obligation to update or revise such statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

SUMMARY

This summary highlights information contained in this information statement and provides an overview of the Company, our separation from Exelon and the distribution of our common stock by Exelon to its shareholders. For a more complete understanding of our business and the separation, you should read this entire information statement carefully, particularly the sections titled "Risk Factors" and "Unaudited Pro Forma Condensed Consolidated Financial Statements" and the audited consolidated financial statements and the notes thereto included in this information statement.

Our Business

Our Company is America's leading clean energy company, based on the production of carbon-free electricity. We are the largest supplier of clean energy and sustainable solutions to homes, businesses, public sector, community aggregations and a range of wholesale customers (such as municipalities, cooperatives and other strategics) across the continental U.S., backed by approximately 33,000 megawatts of generating capacity consisting of nuclear, wind, solar, natural gas and hydro assets. In 2020, the Company produced nearly 12% of the nation's carbon-free energy (based solely on generation output of electricity) according to published reports on energy delivery by the U.S. Energy Information Administration, making it an important partner to businesses and state and local governments that are setting ambitious carbon-reduction goals and seeking long-term solutions to the climate crisis.

The Company is comprised of two primary business units: Constellation NewEnergy, Inc. and Exelon Generation Company, LLC. The combined Company operates in 48 states, Canada and the U.K. and employs approximately 12,500 people.

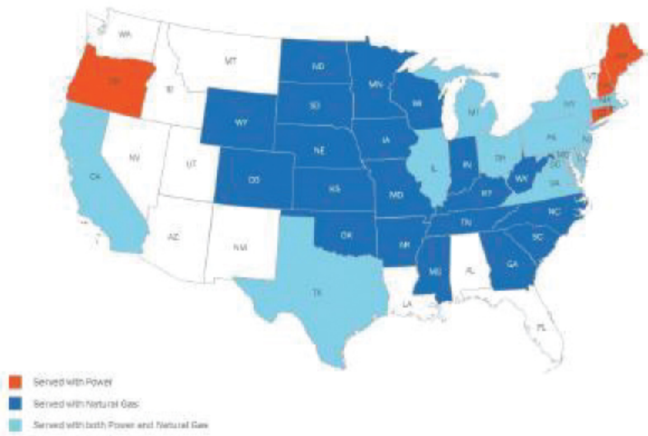
We believe shareholder value is built on a foundation of operational excellence and the pairing of our customer facing platform with our clean energy fleet. We are focused on optimizing cash returns through a disciplined approach to cost management and efficient operations, underpinned by stable and durable margins from our customer-facing business coupled with generation payments associated with our clean energy attributes. We are committed to maintaining investment grade credit ratings, to returning value to our shareholders (subject to approval by our Board of Directors) and to investing in clean energy solutions.

Our Operations

Customer-Facing Business: Constellation NewEnergy, Inc.

Constellation is one of the nation's largest and most innovative energy suppliers, serving diverse customers of all sizes across the U.S. through operations focused around power supply, gas supply and energy solutions. Constellation is active in all domestic wholesale power and gas markets spanning most of the lower 48 states and has complementary retail activity across many of those states.

Constellation Retail Has a Diverse Geographic Footprint



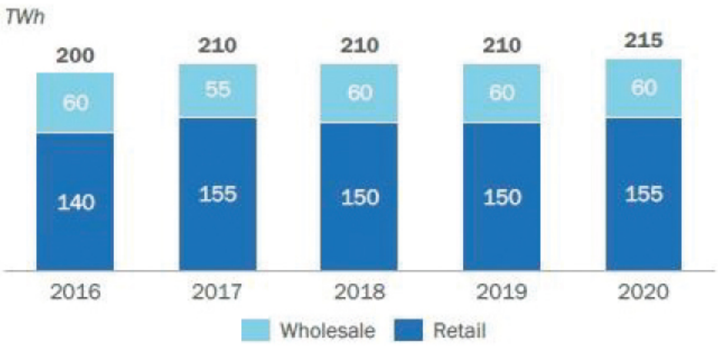
Power Supply. Constellation is a leader in power supply, supplying 215 TWhs annually to a customer base including utilities, municipalities, cooperatives, commercial and industrial entities, residences, and public sector entities. Its customer base includes three-fourths of Fortune 100 companies. It is the largest retail commercial and industrial power provider and the third largest residential power provider in the U.S., supplying approximately 145 TWh to business and public sector customers and approximately 10 TWh to residential customers.

Constellation's wholesale channel-to-market serves approximately 60 TWh of power load across competitive utility load procurements and bilateral sales to municipalities, coops, banks, and other wholesale entities. Complementary to its national portfolio, Constellation has several decades of relationships with wholesale counterparties across all domestic power markets as a means of both monetizing its own generation, as well as sourcing contracted generation to meet customer and portfolio needs. With the increased trend toward customer demand for sustainability, this ability to source contracted generation has provided a capital-light way for the Company to provide customers with the renewable products they are demanding to support a cleaner energy ecosystem.

Gas Supply. Constellation is also leader in gas supply, serving 1,600 Bcf of gas annually to a wide range of customers across many sectors, including manufacturing, services, public sector, transportation, and utilities. We have strong capabilities across the entire natural gas value chain, which allows us to optimize our portfolio to provide both low cost and customized solutions to our customers. Similarly, the scope of our natural gas business provides us wide geographic coverage across all domestic natural gas markets.

Customer Acquisition and Retention. Constellation primarily serves commercial and industrial ("C&I") customers across the U.S. These strong, proven customer relationships are a key part of our customer-facing business strategy. High customer satisfaction levels, market expertise, stability and scale drive growth and result in historically-proven business consistency and margins. Customer retention rates have been strong over the last five years across C&I power customer groups, with power C&I renewal rates of 74-79% and an average contract term of 25 months and customer duration of more than six years and with gas C&I retention rates of 90-92%. Constellation is also successful at acquiring new customers by offering a variety of innovative services and products, meeting customers where they are in the buying cycle. While providing customers with the best possible price is a key focus, Constellation leverages its broad suite of electric and gas product structures, oftentimes customized, to provide its customers with the commodity solution that best fits their needs. Future growth will be primarily driven from new and growing digital channels with a focus on innovative products aimed at clean energy solutions.

Constellation is Defined by Consistent Load, Enabling Strong Cash Flows[(a)]



(a) Reflects retail load and wholesale load auction volumes as of December 31, 2020.

Energy Solutions. Constellation benefits from significant economies of scale that allow it to structure highly tailored solutions targeted to a customer's unique power needs and clean energy goals. Constellation is a leader in enabling a clean energy future for its customers through a suite of products and services, beyond power and natural gas, that can be integrated into existing commodity purchasing strategies. Our customer solutions include specialty power and gas products matching customers’ risk tolerance and risk management needs, energy efficiency, carbon free products, energy usage and management solutions, among others. Constellation partners with its customers to provide options along the sustainability continuum, with a focus on renewable, efficiency and technology applications to meet their carbon free energy goals.

Generation

Generation operates the largest zero-carbon fleet in the nation and one of the largest generating fleets in the country.

Generation’s nuclear fleet has current generating capacity of approximately 19 gigawatts and produced 150 TWh (net ownership) of zero-emissions electricity last year — enough to power 13.6 million homes and avoid more than 78 million metric tons of carbon emissions. Generation consistently operates at best in class levels. In 2020, Generation recorded a capacity factor of 95.4%, second only to 2019 performance in fleet history, and an average refueling outage duration of 22 days, 11 days better than the industry average. Generation has ownership interests in thirteen nuclear generating stations currently in service, consisting of 23 units. Generation will continue to be a leading advocate for clean energy policies aimed at preserving and growing clean energy to combat the climate crisis.

Generation also operates more than 12 gigawatts of natural gas, oil, hydroelectric, wind, and solar generation assets, which provide a mix of baseload, intermediate, and peak power generation. Our fossil and renewable fleet has similarly demonstrated a track record of strong performance with a 98.4% power dispatch match[1] and 93.4% renewables energy capture.[2]

Collectively, the combined fleet is nearly 90% carbon-free (based on generation output of electricity) and represents the fourth largest generation portfolio in the U.S. in terms of total generation with meaningful geographic diversity.

The charts below illustrate our supply source as of December 31, 2020:

Supply Source[(a)(b)]

	Generation Output	
	GWh	%
Nuclear	175,085	62.2%
Fossil (primarily natural gas and oil)	19,501	6.9%
Renewable	7,052	2.5%
Purchased Power	79,972	28.4%
Total	**281,610**	**100%**

1 Dispatch match is used to measure the responsiveness of a unit to the market and is expressed as the actual energy revenue net fuel relative to the revenue net fuel when the unit is dispatched by the RTO or Constellation. Unit dispatch match is calculated as follows: (Actual Generation * (Locational Marginal Price — Generation Cost) / (Desired Generation * (Locational Marginal Price — Generation Cost). Locational marginal price represents the hourly market price per MW of energy at the bus closest to the unit. Desired generation equals the MWs the units is asked to run by either Constellation or the RTO. Generation costs represent the full load operating costs, including fuel and variable O&M.

2 Energy capture is an indicator of how efficiently the installed assets capture the natural energy available from the wind and the sun. Energy capture represents an energy-based fraction, the numerator of which is the energy produced by the sum of the wind turbines/ solar panels in the year, and the denominator of which is the total expected energy to be produced during the year. Energy capture for the combined wind and solar fleet is weighted by the relative site projected pre-tax variable revenue, with deductions made for certain events that are non-controllable, such as force majeure events and transmission curtailments.

(a) Nuclear 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.

(b) Renewable includes wind, hydroelectric, solar, and biomass generating assets.

Constellation employs an integrated, ratable hedging strategy to manage commodity price volatility in energy gross margins over time. The generation portfolio has operated under a risk-mitigated ratable hedging strategy for more than a decade in which the prompt three years are hedged on an approximate rolling 90% / 60% / 30% basis — enabling cash flow stability while allowing commercial opportunities to generate value for the enterprise.

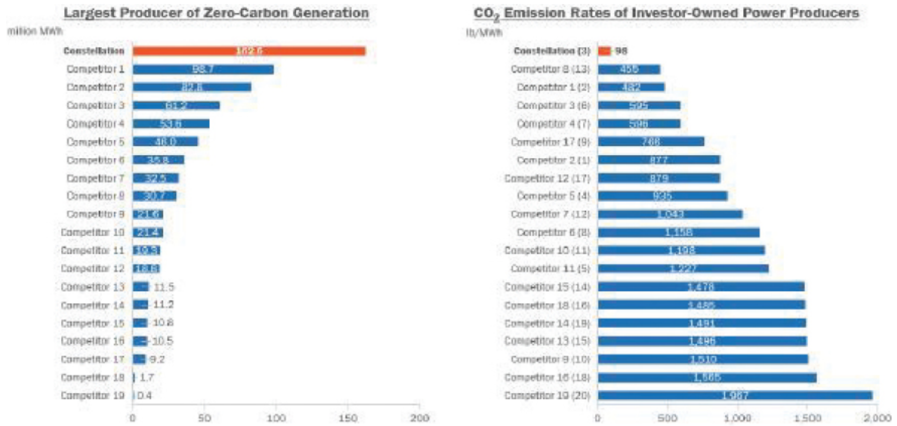
Our Competitive Strengths

We believe that we are well-positioned to execute our business strategy and create superior value for stakeholders based on the following competitive strengths:

- ***We are positioned to help address the climate crisis and lead to a clean energy future***

As a Company, we are committed to a clean energy future, and we believe our generation fleet is essential to helping meet clean energy policy and targets, at the state and national level. Approximately 90% of our generation fleet is emissions free (based on generation output). We do not own coal-fired generation. According to the July 2021 Benchmarking Air Emission report, our Company produces approximately 65% more clean energy than the next leading provider. Our fleet has the lowest emissions intensity — nearly five times less intensive than the next lowest generator.

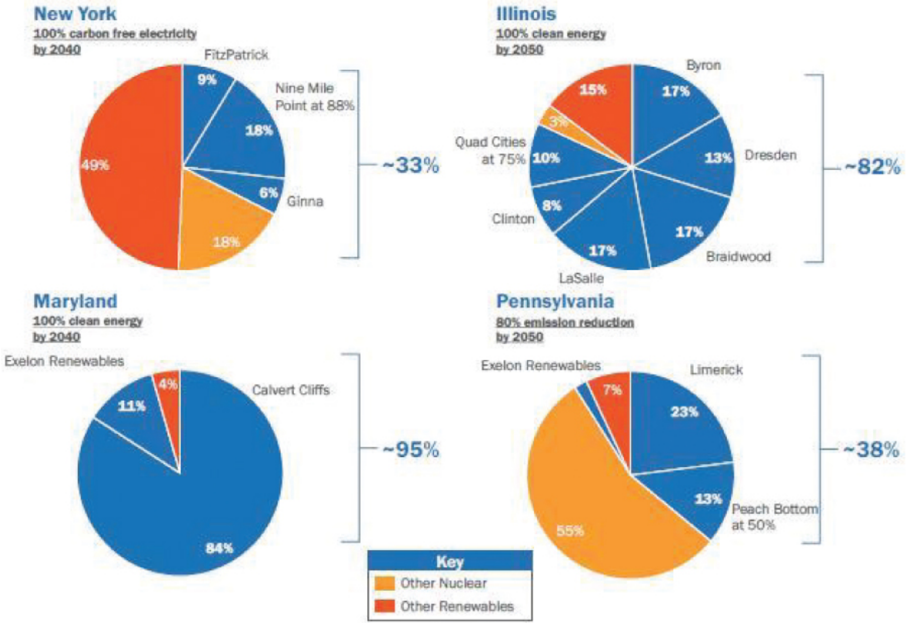
Our Company is the Largest Producer of Clean Electricity in the U.S.[(a)]



(a) Source: Benchmarking Air Emissions, July 2021, published by M.J. Bradley & Associates LLC. Reflects 2019 regulated and non-regulated generation. Number in parentheses is the company's generation ranking in that year.

Our generation fleet is essential to meeting federal and state clean energy goals. Generation produced 12% of the zero-carbon energy nationwide and even more in several states in which we operate — 95% in Maryland, 82% in Illinois, 38% in Pennsylvania and 33% in New York. Each of these states has set decarbonization and clean energy targets. Losing any of our clean assets in these states would be a significant step backward for achieving clean energy or climate goals while also creating higher costs for customers and significant economic hardship for our plant communities.

Generation Plays a Central Role in Enabling States' Respective Clean Energy Goals[a][b]



(a) Source: 2020 U.S. Energy Information Administration data. Assumes whole unit output of CENG generation in 2020. Does not adjust for announced retirement by another operator of the Indian Point 3 nuclear unit in New York. Renewables include hydroelectric, solar, and wind generation and exclude biomass. Reflects clean energy goals as outlined in the state's existing law or goal established by the state Governor.

(b) Generation owns an 82% undivided ownership interest in Nine Mile Point Unit 2.

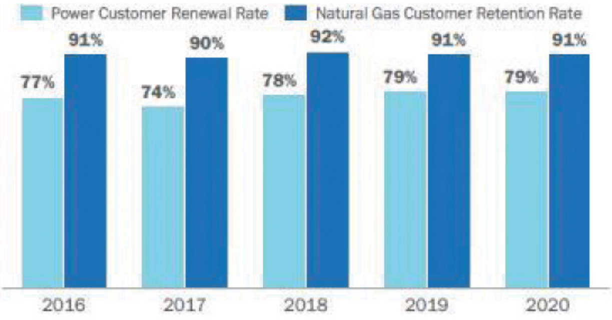
- ***Industry-leading customer-facing business providing sustainability solutions for our customers***

Geographic scale, diversity, customer-tailored product offerings and services, and high customer satisfaction underpin our robust customer-facing platform and enable us to partner with customers to solve their emerging needs on their clean energy goals in a differentiated way.

Constellation is the largest customer facing platform in the U.S., which we view as a source of considerable competitive advantage. Our industry-leading national platform not only allows us to capture operational efficiencies for more effective integration of new customers and acquisitions, but also allows for a scalable go-to-market approach. This enables rapid deployment of new energy services and products and innovative energy technology applications that are responsive to marketplace trends and demands, improving our position for growth.

Constellation's heavy customer concentration in the C&I retail space, coupled with high customer satisfaction, further differentiates the business within the competitive landscape in its ability to provide repeatable, derisked value to the shareholder. Customer concentration in C&I enables more predictable load and stable unit margins, lower customer acquisition costs, and insulation from weather driven volatility. Cash flows are further maximized by high customer satisfaction levels resulting in business consistency, stable unit economics, and high customer win and renewal rates.

Constellation Benefits from Strong Customer Relationships, with Leading C&I Renewal Rates



- ***Best-in-class nuclear operations***

Our world class operations result in industry-leading operating performance at our generation facilities. Our generation fleet has achieved an industry-leading nuclear capacity factor of approximately 94% or higher since 2013 — four percentage points better than the 2020 industry average of approximately 90%. Our 2020 average refueling outage duration was 22 days — 11 days better than the industry average.

- ***Disciplined financial management focused on strong balance sheet and optimizing cash returns***

Our commitment to investment grade credit ratings remains paramount as we prioritize capital allocation to support a strong balance sheet, invest in both clean energy solutions and our customer-facing businesses, enable customer growth and return value to shareholders.

We view a strong balance sheet as a competitive strength in managing through periods of commodity price volatility with heightened agility. We are focused on allocating available cash flow to manage leverage to meet investment grade targets with incremental cash flows allocated to investing in both clean energy solutions and our customer-facing business and returning capital to shareholders. We believe a strong balance sheet and robust cash flow generation, combined with our current presence and scale in diverse markets, will position us favorably in pursuit of value-enhancing growth opportunities.

With high customer satisfaction, strong customer renewal and retention and best-in-class operating expertise, we are well-positioned to deliver strong cash flows. To further support cash flow, we will continue to focus on operational efficiencies and cost management while ensuring the safety and reliability of our operations. In addition, our integrated and ratable hedging activities serve to manage commodity price volatility in energy gross margins over time.

- ***Committed to supporting all stakeholders through a strong commitment to environmental, social and governance practices***

We are committed to the highest standards of corporate governance to help us achieve our performance goals and to maintain the trust and confidence of our shareholders, employees, customers, regulators and other stakeholders. Environmental, Social and Governance principles have been at the core of our business since its original founding and will continue to be core to the Company.

We will continue to support our diverse employees, customers, communities and business partners, ensuring all are able to fully and equitably participate in social, environmental and economic progress. We will maintain the highest standards of corporate governance, operating responsibly and transparently with a continued focus on board refreshment and diversity.

Our Business Strategy

Our business strategy is to maximize value for all of our stakeholders through a particular emphasis on:

Focus on cash returns, business optimization, repeatable customer revenues, and capital allocation.

We run our business with a focus on producing strong, robust cash flows in order to sustain our operations, maintain our investment grade credit targets, and fund shareholder return and growth opportunities. We remain focused on operating efficiency and cost management, while ensuring safety and operational excellence, to support stability in free cash flow generation.

We aim to achieve growth in cash flows from our customer facing business by increasing volumes and driving margin improvement across all channels to market. Increasing volumes are expected to come from organic and acquisitive customer growth, both in commodity offerings as well as reaching previously inaccessible customers through non-commodity energy services and solutions. Increasing margins are expected to come from value-add products, services, and analytics coupled with existing offerings. We can leverage our existing platform to achieve economies of scale benefits on incremental volumes, leading to higher overall margins per customer and improved free cash flow conversion.

We also aim to achieve growth in cash flows from our generation business through a rigorous focus on operating performance and cost optimization. We will continue to evaluate the cost-benefit analysis of all operating and capital allocation decisions to optimize value for our stakeholders, without sacrificing our commitment to safety. Further, our ratable hedging strategies, coupled with stable revenues generated through capacity markets and contracts for zero emissions attributes, will enable the business to continue to mitigate cash flow volatility, while preserving long-term optionality to realize any potential upside from market price improvements and/or state and federal clean energy programs. In addition, we will continue advocating for clean energy policies and seek fair compensation for the zero-carbon attributes of our nuclear plants while maintaining the discipline to retire uneconomic assets.

We will employ a disciplined approach to acquisitions that grows future cash flow and supports strategic initiatives. We will continue to evaluate asset and business divestitures to rationalize the portfolio and optimize cash proceeds.

Capital allocation decisions are made on a cash return basis, as we believe this discipline is necessary to drive consistent long-term value creation for our shareholders. In the years ahead, we expect to deliver substantial free cash flow supported by our stable customer facing business, disciplined hedging strategy and effective cost management, with more than $1.1 billion of cost reductions realized since 2015.

Financial discipline and balance sheet commitment.

We are committed to maintaining sufficient financial liquidity and an appropriate capital structure to support safe, secure and reliable operations, even in volatile market conditions. We believe our investment grade credit rating is a source of competitive advantage, and we intend to continue to maintain our credit position and best-in-class balance sheet. In line with that commitment, available cash flow will first be used to manage leverage to comfortably meet investment grade credit targets, with incremental capital allocated towards shareholder return and disciplined growth.

Excellence in operations.

Value is built on a foundation of operational excellence. We recognize operational efficiency, a culture of continuous improvement and disciplined investment, and robust safety practices as critical drivers.

We have robust safety programs. We have a demonstrated commitment evidenced by our exceptional safety track record, underpinned by a strong compliance and risk management culture. At Constellation, we have strong, durable relationships with our customers resulting in stable financial margins, underpinned by strong operational performance in our customer-facing business.

Taking the lead on driving toward a clean energy future.

We are committed to enabling a clean energy future through our generation operations and our customer-facing business. Through our two businesses, we aim to serve as an indispensable partner to businesses and the state and local governments that are setting ambitious carbon-reduction goals and seeking long-term solutions to the climate crisis. We advocate for policies that address the climate crisis and preserve and grow clean energy.

We are differentiated by the cleanest generation fleet in the country. As environmental sustainability continues to build momentum and grows for businesses across the country, the demand for clean and sustainable energy solutions increases. Constellation offers clean products to help customers meet their sustainability goals. We expect our product offerings to evolve with our customers' needs.

For nearly two decades, we have been a strong advocate for policies that would address the climate crisis. We will continue to be a leading advocate at the federal level and in the states in which we operate for policies reducing greenhouse emissions, and preserving and growing clean energy.

Our Key Markets

We operate across various markets in the U.S., as well as Canada and the U.K. Our generation resources allow us to generate, procure, and sell electricity to retail and wholesale customers, highlighting the integrated nature of our business. We also have the ability to contract for generation in the markets in which we operate, further facilitating our ability to match generation output to customer demand (gen-to-load) and customer-to-supply as an integrated business. We have five reportable segments covering the following geographical areas:

- Mid-Atlantic: 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: Western half of PJM and the U.S. footprint of MISO, excluding MISO's Southern Region
- New York: NYISO
- Texas: ERCOT
- Other Power Regions: New England, South, West and Canada

Generation Markets

PJM. 65% of our generation fleet, as measured by net generating capacity, operates within the PJM market. By MW, our generation fleet in PJM consists of approximately 78% nuclear, 9% renewables, 8% gas and 5% oil. PJM is the largest power market in the U.S. It comprises all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM is one of the most advanced power markets in the U.S., with nodal day-ahead and real-time energy markets, ancillary service products, and a forward capacity market.

ERCOT. 12% of our generation fleet, as measured by net generating capacity, operates within the ERCOT market. By MW, our generation fleet in ERCOT consists of approximately 97% gas and 3% renewables. As an energy-only market, ERCOT's market design is different from other competitive electricity markets in the U.S., as its resource adequacy is predominately dependent on free market processes and energy market price signals.

NYISO. 6% of our generation fleet, as measured by net generating capacity, operates within the NYISO market. By MW, our generation fleet in NYISO consists of almost 100% nuclear. NYISO features liquid day-ahead and real-time energy markets, ancillary service markets, and a spot capacity market, called the ICAP market, which clears capacity up to 6 months in advance of the delivery period. As a result, our power assets within NYISO can earn revenues from liquid ancillary, energy, and capacity markets.

Other power markets. The remaining 17% of our generation fleet operates in other markets, including CAISO, ISO-NE, MISO and SPP in the U.S., and AESO in Canada. Our generation in these markets, by MW, consists of approximately 20% nuclear, 46% gas, 13% oil and 20% renewables.

The CAISO market serves customers primarily in California. CAISO features day-ahead and real-time energy markets and ancillary service markets. While CAISO does not operate a formal capacity market, it does have a mandatory resource adequacy requirement.

The ISO-NE market covers the six states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. It offers day-ahead and real time energy markets, ancillary service products and a forward capacity market.

MISO is an RTO that covers all or parts of 15 states: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, as well as the Canadian province of Manitoba. MISO operates day-ahead and real time energy markets and ancillary service markets. Capacity requirements are addressed through bilateral transactions or a voluntary annual auction that MISO administers.

SPP has members in 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. It also provides contract reliability coordination services in Arizona, Colorado and Utah. SPP operates day-ahead and real-time energy markets and transmission service markets.

AESO provides the function of Independent System Operator in Alberta, Canada, where we own one generation asset. It is currently an energy-only model and does not operate a capacity market. AESO also operates a separate ancillary services market where resources provide specific services that help maintain grid reliability.

Customer Markets

Our integrated business also consists of the physical delivery and marketing of power and natural gas across multiple geographical regions through Constellation, our customer-facing business. Constellation serves power and natural gas across all competitive markets, reaching approximately 2 million customers, including three-fourths of the Fortune 100, approximately 216,500 business and public sector customers, and about 1.6 million unique residential customers. Constellation also has a vibrant non-commodity element of its customer facing business, providing sustainability, efficiency and technology solutions to provide a comprehensive suite of energy solutions to meet customers' growing and evolving needs.

Summary of Risk Factors

An investment in the Company's common stock is subject to a number of risks, including market, financial, regulatory and operational risks related to our business, our separation from Exelon, and our common stock. Set forth below are some, but not all, of these risks.

- **Risks related to market and financial factors** primarily include:
  - the price of fuels, in particular the price of natural gas, which affects power prices,
  - the generation resources in the markets in which we operate,
  - our ability to operate our generating assets, our ability to access capital markets, and the impacts on our results of operations due to the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19),
  - the impacts of on-going competition, and
  - emerging technologies and business models, including those related to climate change mitigation and transition to a low carbon economy.
- **Risks related to regulatory, legislative and legal factors** primarily include changes to, and compliance with, the laws and regulations that govern:
  - the design of power markets,
  - the renewal of permits and operating licenses,
  - environmental and climate policy, including zero emission credit programs, and

  - tax policy.
- **Risks related to operational factors** primarily include:
  - changes in the global climate could produce extreme weather events, which could put our facilities at risk, and such changes could also affect the levels and patterns of demand for energy and related services,
  - the safe, secure and effective operation of our nuclear facilities and the ability to manage effectively the associated decommissioning obligations,
  - the ability of energy transmission and distribution companies to maintain the reliability, resiliency and safety of their energy delivery systems, which could affect our ability to deliver energy to our customers and affect our operating costs, and
  - physical and cyber security risks for us as an owner-operator of generation facilities and as a participant in commodities trading.
- **Risks related to our separation from Exelon** primarily include:
  - challenges to achieving the benefits of separation, including limited business diversification, loss of economies of scale in sourcing goods and services, and the need to replicate several services provided by Exelon (such as treasury, finance, human resources, investor relations and legal), which will require additional resources and expense,
  - little control over the terms and timing of the separation (including regulatory approvals), which are determined by Exelon (and with respect to regulatory approvals, the applicable regulator), and Exelon's ability to change the terms at any time or elect not to proceed,
  - performance by Exelon and us under the transaction agreements, including indemnification responsibilities tied to the allocation of businesses and liabilities, and
  - restrictions on future capital-raising or strategic transactions during the two-year period following the distribution arising from the need to protect the tax-free treatment of the distribution.
- **Risks related to our common stock** primarily include:
  - following the separation, there can be no assurance that the combined trading prices of Exelon common stock and our common stock will be equal to or greater than the trading price of Exelon shares prior to the separation,
  - the absence of a currently existing trading market for our stock and possible volatility in the market for our stock as holders of Exelon stock seek to reorganize their holdings based on stock index or industry strategies, investment policies or other factors, in addition to the general factors affecting the market price of common stock,
  - our status as a holding company dependent on cash flows from our subsidiaries to meet financial obligations, and
  - certain anti-takeover provisions in our charter and bylaws that could have the effect of delaying or discouraging an acquisition of our company or a change in its management.

These and other risks relating to our business, our industry, the distribution and separation and our common stock are discussed in greater detail under the heading "Risk Factors" on page 26 of this information statement. You should read and consider all of these risks carefully.

Company Information

Constellation Energy Corporation was incorporated in Pennsylvania on June 15, 2021. Our principal executive offices are at 1310 Point Street, Baltimore, Maryland, 21231, and our telephone number is (610) 765-5959. Our website is constellationenergy.com. The information and other content contained in, or accessible through, our website are not part of, and are not incorporated into, this information statement, and investors should not rely on any such information in deciding whether to invest in our common stock.

The Separation

The following provides a summary of the terms of the separation. For a more detailed description of the matters described below, see “The Separation” beginning on page 45 of this information statement.

Overview

On February 21, 2021, Exelon’s board of directors unanimously authorized management to pursue a plan to separate its competitive generation and customer-facing businesses into a stand-alone publicly traded company, which we refer to as the separation in this information statement. The separation will occur through a distribution to Exelon’s shareholders of all of the shares of common stock of the Company, which will own Exelon Generation Company, LLC, including its competitive generation and customer-facing energy businesses. Following the distribution, Exelon shareholders will own 100% of the shares of our common stock.

Before our separation from Exelon, we will enter into a separation agreement and several other agreements with Exelon to effect the separation and provide a framework for our relationship with Exelon after the separation. These agreements will govern the relationships between us and Exelon subsequent to the completion of the separation and address responsibility for liabilities and obligations (including employee benefits and tax-related assets and liabilities) relating to the separated businesses attributable to periods prior to, at and after our separation from Exelon. For more information on the separation agreement and related agreements, see “Certain Relationships and Related Party Transactions” in this information statement.

As more fully described in “The Separation — Reasons for the Separation”, the Exelon board of directors believes that the separation will increase both the value of Exelon’s competitive generation, customer-facing and related businesses as well as the value of Exelon’s regulated utility businesses, in both the short and long terms.

The separation is subject to the satisfaction or waiver of certain conditions, including the receipt of regulatory approvals from the NRC, FERC and NYPSC. Requests for NRC, FERC and NYPSC approvals were submitted on February 25, 2021. In addition, until the distribution has occurred, Exelon’s board of directors has the right to not proceed with the distribution, even if all of the conditions are satisfied. See “The Separation — Conditions to the Distribution” in this information statement for the status of these approvals.

Reasons for the Separation

Exelon is comprised of six regulated utility operating companies that together serve more than 10 million customers, and Generation, an electricity producer and a competitive energy retailer. The utility operating companies provide electricity transmission and distribution and gas distribution services within relatively defined geographic areas under service terms, conditions and rates that are regulated by public utility commissions based on each utility’s investment in plant, property and equipment, referred to as rate base, and their operating costs. Generation generates electricity primarily from nuclear generating plants and sells electricity and natural gas to wholesale and retail customers within a broad geographic area under service terms, conditions and prices determined by competitive market forces.

The Exelon board of directors believes that the separation of the competitive generation and customer-facing energy businesses from the regulated utility businesses is in the best interest of Exelon and its shareholders for a number of reasons, including:

- *Direct investment identity* — Exelon’s board of directors believes that Exelon’s regulated utility businesses and our competitive businesses appeal to different types of investors with different industry focuses, investment goals and risk profiles.
- *More specialized strategic focus* — The separation will allow each company to more effectively pursue its own distinct operating priorities and strategies, without taking into account potentially conflicting or competing needs and objectives of two disparate businesses operating in a single company. As a standalone company, the Company may be able to pursue investments or acquisitions

in the competitive energy infrastructure space that Exelon's current shareholders would not find attractive as it would increase Exelon's exposure to non-regulated businesses.

- *More efficient allocation of capital* — The separation will permit each company to concentrate its financial resources solely on its own operations, providing greater flexibility to invest capital in its business in a time and manner appropriate for its distinct strategy and business needs.
- *Allows each business to maintain risk profiles more appropriate for its shareholders* — The competitive generation and customer-facing energy businesses of Exelon are exposed to certain market risks, including, in the near term, the volatility in the price of power, natural gas and other commodities. The Company will be committed to disciplined risk-mitigation policies, including a ratable hedging strategy, and Exelon's board of directors believes that separating the Company from the regulated utilities of Exelon will give our management further flexibility to manage our risk.
- *Aligns management incentives* — The separation will permit the creation of equity-based incentive compensation programs for each of the companies that is expected to reflect more closely the efforts and performance of each company's management and will allow each company to better recruit, retain and motivate employees pursuant to compensation policies that are appropriate for their respective lines of business.

For information about risks related to the separation, see "Risk Factors — Risks Relating to Our Separation from Exelon" below in this information statement. Neither Exelon nor we can assure you that, following the separation, any of the benefits described above or otherwise will be realized to the extent anticipated or at all.

Questions and Answers About the Separation

The following is a summary of the terms of the separation in a question and answer format. As a summary, it may not cover all of the information that may be important to you. You should read the section entitled "The Separation" beginning on page 45 of this information statement for a more detailed description of the matters described below.

Q: ***What is the separation?***

A: The separation is the spin-off distribution of our businesses from Exelon. Once the separation is complete, we will be an independent, publicly traded company focused on our competitive power generation and customer-facing energy businesses. Exelon will continue as an independent, publicly traded company focused on its regulated utility businesses.

Q: ***Why is Exelon separating the Company from Exelon?***

A: Exelon's board of directors and management believe that the separation will provide, for each of Exelon and the Company following the separation, a more direct investment identity, enhanced strategic and management focus, more efficient allocation of capital, and will align management incentives more effectively.

The separation will create the nation's largest pure transmission and distribution utility and the largest carbon-free power producer and retail energy solutions provider, each with the financial strength to drive long-term stability and innovation, with the expectation that both companies will have compelling growth prospects as stand-alone companies and that the financial markets will ascribe valuations that more appropriately recognize the inherent strengths of each company. These benefits are more fully described under the caption "The Separation — Reasons for the Separation" below in this information statement.

Q: ***Why is the separation of the two companies structured as a distribution?***

A: Exelon believes that a distribution of our shares is the most efficient way to separate the Company in a manner that is intended to enhance long-term value for Exelon shareholders.

Q: ***What is the distribution?***

A: The distribution is the method by which Exelon will effectuate the separation. In the distribution, Exelon will distribute to its shareholders all of the shares of our common stock that it owns. Exelon will not retain any ownership interest in us. The number of shares of Exelon common stock you own will not change as a result of the distribution.

Q: ***What will I receive in the distribution?***

A: As a holder of Exelon common stock, you will receive a dividend of one share of our common stock for every three shares of Exelon common stock you hold on the record date (see next question). Your proportionate interest in Exelon will not change as a result of the distribution. For a more detailed description, see “The Separation” below in this information statement.

Q: ***What is the record date for the distribution, and when will the distribution occur?***

A: The record date is 5:00 p.m., Eastern Time, on January 20, 2022. We expect that EQ Shareowner Services (the “*Distribution Agent*”) will act as distribution agent and will distribute to Exelon shareholders the shares of our common stock on February 1, 2022, which we refer to as the distribution date.

Q: ***What will be distributed in the distribution?***

A: Approximately 326.5 million shares of our common stock will be distributed in the distribution, based on the number of shares of Exelon common stock outstanding as of December 31, 2021. The actual number of shares of our common stock to be distributed will be calculated on the record date. The shares of our common stock to be distributed by Exelon will constitute all of the shares of our common stock issued and outstanding immediately prior to the distribution.

Q: ***What are the conditions to the distribution?***

A: The distribution is subject to a number of conditions, including, among others

- receipt of regulatory approvals from the NRC, the NYPSC and FERC
- the SEC declaring effective the registration statement of which this information statement forms a part
- the receipt by Exelon of a private letter ruling from the IRS (the “*IRS Ruling*”) and an opinion of its counsel, Sidley Austin LLP, together substantially to the effect that the distribution, together with certain related transactions, will qualify as a tax-free reorganization under Sections 355 and 368(a)(1)(D) of the IRC and
- final approval of the distribution by Exelon’s board of directors.

For a more detailed description, see “The Separation — Conditions to the Distribution” below in this information statement.

Q: ***Can Exelon decide to cancel the distribution even if all of the conditions have been satisfied?***

A: Yes. Exelon’s board of directors may, in its sole discretion and at any time prior to the distribution date, terminate the distribution, even if all of the conditions to the distribution have been satisfied.

Q: ***What do I have to do to participate in the distribution?***

A: No action is required on your part, but we urge you to read this document carefully. Shareholders who hold Exelon common stock as of the record date will not be required to pay any cash or deliver any other consideration, including any shares of Exelon common stock, to receive the shares of our common stock distributable to them in the distribution. In addition, no shareholder approval of the distribution is required or is being sought. We are not asking you for a vote and are not requesting that you send a proxy card.

Q: ***How will Exelon distribute shares of Company common stock?***

A: If you are a registered shareholder (meaning you own your stock directly through an account with Exelon’s transfer agent), EQ Shareowner Services will mail you a book-entry account statement that reflects the number of shares of our common stock you own. We will not issue physical certificates, even if requested. For a more detailed description, see “The Separation — Manner of Effecting the Separation — Distribution of Shares of Our Common Stock” below in this information statement.

Q: ***What if I hold my shares through a broker, bank or other nominee?***

A: If you own your Exelon shares beneficially through a bank, broker or other nominee, your bank, broker or other nominee will credit your account with the shares of our common stock you receive in the distribution.

Q: ***If I sell my shares of Exelon common stock on or before the distribution date, will I still be entitled to receive shares of Company common stock in the distribution?***

A: If you sell your shares of Exelon common stock on or prior to the distribution date, you may also be selling your right to receive shares of our common stock. For a more detailed description, see “Trading Market — Trading Prior to the Distribution Date” below in this information statement. You are encouraged to consult with your financial advisor regarding the specific implications of selling your Exelon common stock prior to or on the distribution date.

Q: ***How will fractional shares be treated in the distribution?***

A: No fractional shares of our common stock will be distributed in connection with the distribution. Instead, the Distribution Agent will aggregate all fractional shares into whole shares and sell the whole shares in the open market at prevailing market prices. The Distribution Agent will then distribute the aggregate cash proceeds of the sales, net of brokerage fees and other costs, pro rata to each Exelon shareholder who would otherwise have been entitled to receive a fractional share in the distribution. The receipt of cash in lieu of fractional shares generally will be taxable to the recipient shareholders as described in “The Separation — Material U.S. Federal Income Tax Consequences of the Separation” beginning on page 48 of this information statement. For a more detailed description of the treatment of fractional shares, see “The Separation — Treatment of Fractional Shares” below in this information statement.

Q: ***Who will serve on the Company’s board of directors?***

A: The individuals which we expect to serve on our board of directors at the time of the separation are identified in “Management” beginning on page 149 of this information statement.

Q: ***Who will manage the Company following the separation?***

A: The members of our management team are identified and discussed in “Management” beginning on page 149 of this information statement.

Q: ***What are the U.S. federal income tax consequences of the distribution to U.S. shareholders?***

A: It is a condition to the completion of the distribution that Exelon receive the IRS Ruling and an opinion from its counsel, Sidley Austin LLP, together substantially to the effect that the distribution, together with certain related transactions, will qualify as a tax-free reorganization under Sections 355 and 368(a)(1)(D) of the IRC. Exelon has received the IRS Ruling. The IRS Ruling relies, and the opinion will rely, on certain facts and assumptions, and certain representations from us and Exelon regarding the past and future conduct of our respective businesses and other matters. Assuming such qualification, no gain or loss will be recognized by, or includible in the income of, Exelon shareholders upon the receipt of shares of our common stock pursuant to the distribution. However, Exelon shareholders will recognize gain or loss with respect to any cash received in lieu of any fractional shares. See “The Separation — Material U.S. Federal Income Tax Consequences of the Separation” beginning on page 48 of this information statement and “Risk Factors — Risks Relating to Our Separation from Exelon” beginning on page 37 of this information statement for more information regarding the potential tax consequences to you of the distribution.

Q: ***How will the Distribution affect my tax basis in Exelon common stock?***

A: Assuming that the distribution is tax-free to Exelon shareholders (except with respect to cash received in lieu of fractional shares), your tax basis in Exelon common stock held by you immediately prior to the distribution will be allocated between that Exelon common stock and our common stock received in the distribution in proportion to the relative fair market values of each immediately following the distribution. See “The Separation — Material U.S. Federal Income Tax Consequences of the Separation” beginning on page 48 of this information statement for a more detailed description of the effects of the distribution on your tax basis in Exelon common stock and our common stock.

Q: ***What if I want to sell my shares of Exelon common stock or my shares of Company common stock?***

A: Neither Exelon nor the Company can make any recommendations on the purchase, retention or sale of shares. You should consult with your financial advisors, such as your stockbroker, bank or tax advisor.

If you decide to sell any shares of Exelon common stock after the record date, but before the distribution date, you should make sure your broker, bank or other nominee understands whether you want to sell your Exelon common stock, our common stock you will be entitled to receive in the distribution, or both. If you sell your Exelon common stock prior to the record date or sell your entitlement to receive shares of our common stock in the distribution on or prior to the distribution date, you will not receive any shares of our common stock in the distribution. For a more detailed description, see “Trading Market — Trading Prior to the Distribution Date” below in this information statement.

Q: ***Are there risks associated with owning shares of Company common stock?***

A: Yes. Our business is subject to both general and specific business risks relating to its operations. Our business is also subject to risks relating to the separation, and, following the distribution, we will be subject to risks relating to being an independent, publicly traded company. Accordingly, you should read carefully the information set forth in the section entitled “Risk Factors” beginning on page 26 of this information statement.

Q: ***Will the number of Exelon shares I own change as a result of the distribution?***

A: No, the number of shares of Exelon common stock you own will not change as a result of the distribution.

Q: ***What will happen to the listing of Exelon common stock?***

A: After the distribution, it is anticipated that Exelon will continue to be traded on NASDAQ under the symbol “EXC.”

Q: ***What will the Company’s dividend policy be after the separation?***

A: We do not have a written policy regarding dividends; however, we expect that we will pay dividends on our common stock commencing following the first full fiscal quarter after the separation. The timing, declaration, amount of and payment of any dividends will be within the sole discretion of our board of directors and will depend on a number of factors. See “Dividend Policy” beginning on page 55 of this information statement.

Q: ***Will Company common stock trade on a stock market?***

A: Currently, there is no public market for our common stock. Subject to the consummation of the distribution, we have applied to list our common stock on NASDAQ under the symbol “CEG.” We cannot predict the trading prices for our common stock when that trading begins. We anticipate that trading in shares of our common stock will begin on a when-issued basis on or shortly before the record date and will continue up to and including the distribution date. The term “when-issued” means that shares can be traded prior to the time shares are actually available or issued. On the distribution date, any when-issued trading in respect of our common stock will end and regular way trading in shares of our common stock will begin on the first trading day following the distribution date. “Regular way” trading refers to trading after a security has been issued and typically involves a transaction that settles on the second full business day after the date of trade.

If trading begins on a when-issued basis, you may purchase or sell our common stock up to and including the distribution date, but your transaction will not settle until after the distribution date. For more information regarding regular way trading and when-issued trading, see “Trading Market — Trading Prior to the Distribution Date” below in this information statement.

Q: ***What will happen to Exelon restricted stock units and performance share awards in connection with the separation?***

A: Employees who currently hold restricted stock units and performance share awards, including options, will have such units and awards converted to rights in the Company, subject to the distribution ratio. See "Certain Relationships and Related Party Transactions — Agreements with Exelon Related to the Separation — Employee Matters Agreement — Treatment of Exelon Equity-Based Awards" for more information.

Q: ***Will Exelon transfer to the Company any material assets or liabilities prior to the separation?***

A: We do not expect any material asset or liability transfers to us from Exelon to occur other than the contribution of Exelon's equity interest in Generation (including its subsidiaries) that will occur prior to the separation, an expected cash contribution from Exelon to the Company of $1.75 billion, and pension contributions discussed below in this information statement.

Q: ***What will be the relationship between Exelon and the Company following the distribution?***

A: After the distribution, Exelon will not own any shares of our common stock, and each of the Company and Exelon will be independent, publicly traded companies with their own management and boards of directors. However, in connection with the separation, we will enter into a number of agreements with Exelon that will govern the distribution and allocate responsibilities for obligations arising before and after the separation, including, among others, obligations relating to employees and taxes. Exelon and the Company will enter into a transition services agreement, which will provide for the provision of certain transitional services by Exelon to the Company, and vice versa, generally for up to 24 months, subject to certain exceptions for services that are expected to be provided for up to 36 months. Additionally, there are operating and maintenance, power supply, and other agreements between Exelon's utilities and Generation that will not be terminated in connection with the separation. For a more detailed description, see "Certain Relationships and Related Party Transactions — Agreements with Exelon Related to the Separation" below in this information statement.

Q: ***Will the distribution of Company common stock affect the market price of Exelon common stock?***

A: As a result of the separation, we expect the trading price of shares of Exelon common stock immediately following the separation to be different from the trading price of Exelon common shares immediately prior to the separation because the trading price will no longer reflect the value of our businesses. Furthermore, until the market has fully analyzed the value of Exelon without our business, the price of shares of Exelon common stock may fluctuate. There can be no assurance that, following the distribution, the combined value of Exelon common stock and Company common stock will equal or exceed what the value of Exelon common stock would have been in the absence of the distribution.

Q: ***Will I have appraisal rights in connection with the distribution?***

A: No. Holders of Exelon common stock are not entitled to appraisal rights in connection with the distribution.

Q: ***Whom can I contact for more information regarding the Company and the distribution?***

A: If you have questions relating to the mechanics of the distribution, you should contact the Distribution Agent at:

EQ Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
Phone: (866) 388-8558

Before the distribution, if you have other questions relating to the distribution, you should contact Exelon at:

Investor Relations
Exelon Corporation
10 S. Dearborn St.
Chicago, IL 60680
Phone: 312-394-2345
Email: InvestorRelations@exeloncorp.com

After the distribution, if you have any questions relating to the Company, you should contact us at:

Investor Relations
Constellation Energy Corporation
1310 Point Street,
Baltimore, Maryland, 21231
Phone: (610) 765-5959
Email: investorrelations@constellation.com

After the distribution, the transfer agent and registrar for our common stock will be:

EQ Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
Phone: (866) 388-8558

Summary / Terms of the Separation

The following is a summary of the material terms of the separation and other related transactions. Please see “The Separation” beginning on page 45 for a more detailed description of the matters below.

Distributing Company	Exelon Corporation, a Pennsylvania corporation. After the distribution, Exelon will not own any shares of our common stock.
Distributed Company	Constellation Energy Corporation, a Pennsylvania corporation, is a wholly owned subsidiary of Exelon that immediately before the distribution will own Generation, including its subsidiaries. After the distribution, the Company will be a separate, publicly traded company.
Distributed Securities	Exelon will distribute all shares held by it of our common stock, which will be 100% of our common stock issued and outstanding immediately prior to the distribution. Based on the approximately 979.5 million shares of Exelon common stock outstanding on December 31, 2021, and applying the distribution ratio of one share of our common stock for every three shares of Exelon common stock, approximately 326.5 million shares of our common stock will be distributed to Exelon shareholders who hold Exelon common stock as of the record date.
Record Date	January 20, 2022
Distribution Date	February 1, 2022
Distribution Ratio	Each holder of Exelon common stock will receive one share of our common stock for every three shares of Exelon common stock held on the record date. Please note that if you sell your shares of Exelon common stock on or before the distribution date, the buyer of those shares may, in certain circumstances, be entitled to receive the shares of our common stock distributed on the distribution date. See “Trading Market — Trading Prior to the Distribution Date” below in this information statement for more information.
Fractional Shares	The Distribution Agent will not distribute any fractional shares of our common stock to Exelon shareholders. Instead, the Distribution Agent will aggregate fractional shares into whole shares, sell the whole shares in the open market at prevailing market prices and distribute the aggregate cash proceeds, net of brokerage fees and other costs, from the sales pro rata to each holder who would otherwise have been entitled to receive a fractional share in the distribution. Recipients of cash in lieu of fractional shares will not be entitled to any interest on the amounts of payments made in lieu of fractional shares. The receipt of cash in lieu of fractional shares generally will be taxable to the recipient shareholders as described in “The Separation — Material U.S. Federal Income Tax Consequences of the Separation” beginning on page 48 of this information statement.
Distribution Procedures	On the distribution date, the Distribution Agent will distribute the shares of our common stock by crediting those shares to book-entry accounts established by the transfer agent for persons who were shareholders of Exelon as of the record date. Shares of our common stock will be issued only in book-entry form. No paper stock certificates will be issued. You will not be required to make any payment or surrender or exchange your shares of Exelon common stock or take any other action to receive your shares of our common

	stock. However, as discussed below, if you sell shares of Exelon common stock in the regular way market between the record date and the distribution date, you will be selling your right to receive the associated shares of our common stock in the distribution. Registered shareholders will receive additional information from the transfer agent shortly after the distribution date. Beneficial shareholders will receive additional information from their brokers, banks or other nominees.
Distribution Agent	EQ Shareowner Services
Trading Prior to or on the Distribution Date	It is anticipated that, beginning shortly before the record date, and continuing until the distribution date, shares of Exelon common stock will trade in two markets on NASDAQ — a regular way market and an ex-distribution market. Investors will be able to purchase shares of Exelon common stock without the right to receive shares of our common stock in the ex-distribution market for Exelon common stock. Any holder of Exelon common stock who sells Exelon common stock in the regular way market on or before the distribution date will also be selling the right to receive shares of our common stock in the distribution. You are encouraged to consult with your financial advisor regarding the specific implications of selling shares of Exelon common stock prior to or on the distribution date. For a more detailed description, see “Trading Market — Trading Prior to the Distribution Date” below in this information statement.
Trading Market and Symbol	Subject to consummation of the distribution, we intend to list our common stock on NASDAQ under the symbol “CEG.” We cannot predict the trading prices for our common stock when such trading begins. We anticipate that trading in shares of our common stock will begin on a when-issued basis on or shortly before the record date and will continue up to and including the distribution date. On the first trading day following the distribution date, any when-issued trading in respect of our common stock will end and regular way trading in shares of our common stock will begin. If trading begins on a when-issued basis, you may purchase or sell our common stock up to and including the distribution date, but your transaction will not settle until after the distribution date. For more information regarding regular way trading and when-issued trading, see the section entitled “Trading Market — Trading Prior to the Distribution Date” below in this information statement.
Relationship with Exelon after the Distribution	After the distribution, Exelon will not own any shares of our common stock, and each of the Company and Exelon will be separate, publicly traded companies with their own management and boards of directors. However, in connection with the separation, we will enter into a number of agreements with Exelon that will govern the distribution and allocate responsibilities for obligations arising before and after the separation, including, among others, obligations relating to employees and taxes. In addition, we will enter into a transition services agreement pursuant to which Exelon and we will provide certain transition services to each other on an interim basis. Additionally, there are operating and maintenance, power supply, and other agreements between Generation and Exelon’s

	utilities that will not be terminated in connection with the separation. For a more detailed description, see “Certain Relationships and Related Party Transactions — Agreements with Exelon Related to the Separation” below in this information statement.
Conditions to the Distribution	We expect that the distribution will be effective on February 1, 2022, provided that the conditions set forth under the caption “The Separation — Conditions to the Distribution” have been satisfied or waived in Exelon’s sole and absolute discretion. However, even if all of the conditions have been satisfied, Exelon may terminate and abandon the distribution and the related transactions at any time prior to the distribution date.
Risk Factors	Our business is subject to both general and specific business risks related to financial and market factors; regulatory, legislative and legal factors; and operating factors. Our business is also subject to risks relating to the separation, and, following the separation, we will be subject to risks relating to being a publicly traded company. Accordingly, you should read carefully the section entitled “Risk Factors” beginning on page 26 of this information statement.
U.S. Federal Income Tax Consequences	It is a condition to the completion of the separation that Exelon receive the IRS Ruling and an opinion from its counsel, Sidley Austin LLP, together substantially to the effect that the distribution, together with certain related transactions, will qualify as a tax-free reorganization under Sections 355 and 368(a)(1)(D) of the IRC. Assuming such qualification, no gain or loss will be recognized by, or includible in the income of, Exelon shareholders upon the receipt of shares of our common stock pursuant to the distribution. However, Exelon shareholders that are subject to U.S. federal income tax generally will recognize gain or loss with respect to any cash received in lieu of any fractional shares. Exelon has received the IRS Ruling, which is generally binding, unless the relevant facts or circumstances change prior to the closing of the separation. See “The Separation — Material U.S. Federal Income Tax Consequences of the Separation” beginning on page 48 of this information statement and “Risk Factors — Risks Relating to Our Separation from Exelon” on page 37 of this information statement for more information regarding the potential tax consequences to you of the distribution. **Each shareholder is urged to consult his, her or its tax advisor as to the specific tax consequences of the separation transaction to such shareholder, including the effect of any state, local or non-U.S. tax laws and of changes in applicable tax laws.**

Summary Historical and Unaudited Pro Forma Condensed Consolidated Financial Data

On February 21, 2021, Exelon's board of directors authorized management to pursue a plan to separate its competitive generation and customer-facing energy businesses into a stand-alone publicly traded company. The separation will occur through a distribution to Exelon's shareholders of all of the shares of common stock of the Company, which will own Generation, including its competitive generation, customer-facing power and gas supply, and related businesses. Following the distribution, Exelon shareholders will own 100% of the shares of our common stock.

The following table presents the summary historical consolidated financial information and unaudited pro forma condensed consolidated financial information of the Company for the periods and as of the dates indicated.

The summary historical consolidated financial information presented as of and for the nine months ended September 30, 2021 has been derived from the historical unaudited consolidated financial statements of Generation, included elsewhere in this information statement. The summary historical consolidated financial information presented for the year ended December 31, 2020 has been derived from the historical audited consolidated financial statements of Generation, included elsewhere in this information statement.

The summary unaudited pro forma condensed consolidated financial information as of September 30, 2021 and for the nine months ended September 30, 2021 and the year ended December 31, 2020 is derived from our unaudited pro forma condensed consolidated financial statements. The unaudited pro forma condensed consolidated statement of operations for the nine months ended September 30, 2021 and the year ended December 31, 2020 gives effect to the separation and related transactions, including the purchase of the noncontrolling interest in CENG, as if they had occurred on January 1, 2020, the beginning of the most recent fiscal year for which audited financial statements are available. The unaudited pro forma condensed consolidated balance sheet as of September 30, 2021 gives effect to the separation and related transactions, as if they had occurred on September 30, 2021.

The unaudited pro forma condensed consolidated financial statements were prepared in accordance with Article 11 of Regulation S-X. The unaudited pro forma condensed consolidated financial statements were prepared for illustrative and informational purposes only and are not intended to represent what our results of operations or financial position would have been had the separation and the purchase of the noncontrolling interest in CENG occurred on the dates indicated. The unaudited pro forma condensed consolidated financial statements also should not be considered indicative of our future results of operations or financial position as an independent, publicly traded company. The actual financial position and results of operations may differ significantly from the pro forma amounts reflected herein due to a variety of factors. See "Cautionary Note Regarding Forward-Looking Statements" included in this information statement. The unaudited pro forma condensed consolidated financial information does not reflect the realization of any expected cost savings or other synergies as a result of the separation and related transactions, including the purchase of the noncontrolling interest in CENG.

On November 20, 2019, Generation received notice that, pursuant to an April 1, 2014 Put Option Agreement, EDF intended to exercise its put option to sell to Generation its 49.99% equity interest in CENG. Following the required sixty-day notice period, the put option was automatically exercised on January 19, 2020. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation, through a wholly owned subsidiary, purchased EDF's equity interest in CENG for a net purchase price of $885 million, which includes, among other things, a credit for EDF's share of the balance of a preferred distribution payable by CENG to Generation. The difference between the net purchase price and EDF's noncontrolling interest as of the closing date was recorded to Membership interest on our Consolidated Balance Sheet.

On December 16, 2021, the NYPSC issued an order approving a joint proposal agreement with the Staff of the New York State Department of Public Service, the New York State Office of the Attorney General and the Alliance for a Green Economy regarding approval for Exelon's plan to separate its utilities business and Generation, including Generation's three nuclear power plants in New York. The New York joint proposal agreement will impact the Company's existing asset retirement obligations. As a result, on a pro forma basis, the Company revised its asset retirement obligation upward. The New York joint proposal agreement will become effective upon the closing of the separation.

The summary unaudited pro forma condensed consolidated financial information gives pro forma effect to the following:

Separation transaction accounting adjustments

- the issuance of shares of the Company's common stock based on the distribution ratio of one share of our common stock for every three shares of Exelon common stock outstanding on the record date.
- the impact of the separation agreement, employee matters agreement, tax matters agreement, New York joint proposal agreement, and the provisions therein.

CENG put transaction adjustments

- reflects the elimination of CENG's non-controlling interest and interest expense related to the issuance of approximately $880 million under a 364-day term loan credit agreement to fund the purchase of 49.99% noncontrolling interest in CENG from EDF in accordance with the Put Option Agreement.
- the adjustment of the provision (benefit) for income taxes related to the taxation of income previously attributable to noncontrolling interest holders.

The following summary historical consolidated financial information and unaudited pro forma condensed consolidated financial information should be read in conjunction with:

- Management's Discussion and Analysis of Financial Condition and Results of Operations, which is included elsewhere within this information statement.
- the historical unaudited consolidated financial statements and accompanying notes of Generation as of and for the nine months ended September 30, 2021, which are included elsewhere within this information statement.
- the historical audited consolidated financial statements and accompanying notes of Generation as of and for the year ended December 31, 2020, which are included elsewhere within this information statement.
- the accompanying notes to the pro forma financial information.

Generation has been an individual registrant since the registration of their public debt securities under the Securities Act in 2002. As an individual registrant, Generation has historically filed consolidated financial statements to reflect their financial position and operating results as a stand-alone, wholly owned subsidiary of Exelon. To operate as an independent, publicly traded company, we expect our recurring costs to replace certain services to approximate those costs historically allocated to Generation from Exelon. The significant assumptions involved in determining our estimates of the recurring costs of being an independent, publicly traded company include, but are not limited to, costs to perform financial reporting, tax, corporate governance, treasury, legal, internal audit and investor relations activities; compensation expense, including equity-based awards, and benefits; incremental third-party costs with respect to insurance, audit services, tax services, employee benefits and legal services. The operating and maintenance expenses reported in our historical consolidated statements of operations reflect all expenses incurred as a stand-alone company and include allocations of certain Exelon costs. These costs include allocation of Exelon corporate costs that benefit us, including corporate governance, executive management, finance, legal, information technology, human resources, and other general and administrative costs. We estimate the costs to operate as an independent, publicly traded company approximate the amount of allocated costs that have been presented in our historical consolidated statements of operations and as such an autonomous entity pro forma adjustment has not been made to the accompanying Unaudited Pro Forma Condensed Consolidated Statement of Operations. Certain factors could impact these stand-alone public company costs, including the finalization of our staffing and infrastructure needs.

	Historical		Pro Forma
	Nine Months Ended September 30,		Nine Months Ended September 30,
(In millions, except per share data)	2021	2020	2021
Statement of Operations Information:			
Total operating revenues	$14,117	$13,272	$14,117
Operating expenses			
Purchased power and fuel	8,103	6,967	8,103
Purchased power and fuel from affiliates	—	(6)	—
Operating and maintenance	2,955	3,779	3,386
Operating and maintenance from affiliates	458	409	—
Depreciation and amortization	2,735	1,161	2,776
Taxes other than income taxes	354	364	354
Total operating expenses	14,605	12,674	14,619
Gain on sales of assets and businesses	144	12	144
Operating (loss) income	(344)	610	(358)
Total other income and (deductions)	336	(78)	309
(Loss) Income before income taxes	(8)	532	(49)
Income taxes	108	41	70
Equity in losses of unconsolidated affiliates	(6)	(6)	(6)
Net (loss) income	(122)	485	(115)
Net income (loss) attributable to noncontrolling interests	125	(85)	278
Net (loss) income attributable to membership interest or common shareholders	$ (247)	$ 570	$ (393)
Average shares of common stock outstanding[(a)]			
Basic			326
Diluted			326
Earnings per average common share[(a)]			
Basic			$ (1.20)
Diluted			$ (1.20)
Statement of Cash Flow Information:			
Net cash provided by operating activities	$ 974	$ 1,363	
Net cash provided by investing activities	2,639	1,289	
Net cash used in financing activities	(1,921)	(2,378)	
Balance Sheet Data (at period end):			
Total current assets	$ 8,587		$10,099
Property, plant, and equipment, net	19,574		20,181
Total deferred debits and other assets	19,849		18,657
Total assets	48,010		48,937
Total current liabilities	7,796		7,796
Long-term debt	4,593		4,593
Long-term debt to affiliate	321		—
Total deferred credits and other liabilities	23,265		24,654
Total liabilities	35,975		37,043
Total member’s or shareholder’s equity	11,634		11,493
Total equity	12,035		11,894

(In millions, except per share data)	Historical 2020	Historical 2019	Historical 2018	Pro Forma 2020
	Year Ended December 31,			Year Ended December 31,
Statement of Operations Information:				
Total operating revenues	$17,603	$18,924	$20,437	$17,603
Operating expenses				
Purchased power and fuel	9,592	10,849	11,679	9,585
Purchased power and fuel from affiliates	(7)	7	14	—
Operating and maintenance	4,613	4,131	4,803	5,128
Operating and maintenance from affiliates	555	587	661	—
Depreciation and amortization	2,123	1,535	1,797	2,177
Taxes other than income taxes	482	519	556	482
Total operating expenses	17,358	17,628	19,510	17,372
Gain on sales of assets and businesses	11	27	48	11
Operating income	256	1,323	975	242
Total other income and (deductions)	580	594	(610)	542
Income before income taxes	836	1,917	365	784
Income taxes	249	516	(108)	236
Equity in losses of unconsolidated affiliates	(8)	(184)	(30)	(8)
Net income	579	1,217	443	540
Net (loss) income attributable to noncontrolling interests	(10)	92	73	(7)
Net income attributable to membership interest or common shareholders	$ 589	$ 1,125	$ 370	$ 547
Average shares of common stock outstanding[a]				
Basic				326
Diluted				326
Earnings per average common share[a]				
Basic				$ 1.68
Diluted				$ 1.68
Statement of Cash Flow Information:				
Net cash provided by operating activities	$ 584	$ 2,873	$ 3,861	
Net cash provided by (used in) investing activities	1,958	(1,867)	(2,531)	
Net cash used in financing activities	(2,664)	(1,460)	(981)	
Balance Sheet Data (at period end):				
Total current assets	$ 6,947	$ 7,076		
Property, plant, and equipment, net	22,214	24,193		
Total deferred debits and other assets	18,933	17,726		
Total assets	48,094	48,995		
Total current liabilities	5,219	7,289		
Long-term debt	5,566	4,464		
Long-term debt to affiliate	324	328		
Total deferred credits and other liabilities	22,309	21,084		
Total liabilities	33,418	33,165		
Total member’s or shareholder’s equity	12,399	13,484		
Total equity	14,676	15,830		

(a) The pro forma weighted-average basic and diluted shares outstanding and pro forma basic and diluted earnings per share for the nine months ended September 30, 2021 and year ended December 30, 2020 reflect the estimated number of outstanding shares of our common stock upon the consummation of the separation. We have estimated the number of outstanding shares of our common stock based on the number of shares of Exelon common stock outstanding on September 30, 2021 and applying the distribution ratio of one share of our common stock for every three shares of Exelon common stock.

RISK FACTORS

You should carefully consider each of the following risk factors and all of the other information set forth in this information statement. Based upon information currently known to us, the following information identifies the material risk factors affecting our company. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business, financial condition or results of operations. In addition, past financial performance may not be a reliable indicator of future performance and historical trends should not be used to anticipate results or trends in future periods.

The risks we face can be categorized as risks related to: market and financial factors; regulatory, legislative and legal factors; operational factors; our separation from Exelon; and our common stock:

- **Risks related to market and financial factors** primarily include:
  - the price of fuels, in particular the price of natural gas, which affects power prices,
  - the generation resources in the markets in which we operate,
  - our ability to operate our generating assets, our ability to access capital markets, and the impacts on our results of operations due to the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19),
  - the impacts of on-going competition, and
  - emerging technologies and business models, including those related to climate change mitigation and transition to a low carbon economy.
- **Risks related to regulatory, legislative and legal factors** primarily include changes to, and compliance with, the laws and regulations that govern:
  - the design of power markets,
  - the renewal of permits and operating licenses,
  - environmental and climate policy, including zero emission credit programs, and
  - tax policy.
- **Risks related to operational factors** primarily include:
  - changes in the global climate could produce extreme weather events, which could put our facilities at risk, and such changes could also affect the levels and patterns of demand for energy and related services,
  - the safe, secure and effective operation of our nuclear facilities and the ability to effectively manage the associated decommissioning obligations,
  - the ability of energy transmission and distribution companies to maintain the reliability, resiliency and safety of their energy delivery systems, which could affect our ability to deliver energy to our customers and affect our operating costs, and
  - physical and cyber security risks for us as an owner-operator of generation facilities and as a participant in commodities trading.
- **Risks related to our separation from Exelon** primarily include:
  - challenges to achieving the benefits of separation, including limited business diversification, loss of economies of scale in sourcing goods and services, and the need to replicate certain services provided by Exelon (such as treasury, finance, human resources, investor relations and legal), which will require additional resources and expense,
  - little control over the terms and timing of the separation (including regulatory approvals), which are determined by Exelon (and with respect to regulatory approvals, the applicable regulator), and Exelon may change those terms at any time or elect not to proceed,
  - performance by Exelon and us under the transaction agreements, including indemnification responsibilities tied to the allocation of businesses and liabilities, and

  - restrictions on future capital-raising or strategic transactions during the two-year period following the distribution arising from the need to protect the tax-free treatment of the distribution.

- **Risks related to our common stock** primarily include:
  - following the separation, there can be no assurance that the combined trading prices of Exelon common stock and our common stock will be equal to or greater than the trading price of Exelon shares prior to the separation,
  - the absence of a currently existing trading market for our stock and possible volatility in the market for our stock as holders of Exelon stock seek to reorganize their holdings based on stock index or industry strategies, investment policies or other factors, in addition to the general factors affecting the market price of common stock,
  - our status as a holding company is dependent on cash flows from our subsidiaries to meet financial obligations, and
  - certain anti-takeover provisions in our charter and bylaws that could have the effect of delaying or discouraging an acquisition of our company or a change in its management.

Risks Related to Market and Financial Factors

We are exposed to price volatility associated with both the wholesale and retail power markets and the procurement of nuclear and fossil fuel.

We are exposed to commodity price risk for natural gas and the unhedged portion of our electricity generation supply portfolio. Our earnings and cash flows are therefore exposed to variability of spot and forward market prices in the markets in which we operate.

Price of Fuels. The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit.

Cost of Fuel. We depend on nuclear fuel and fossil fuels to operate most of our generating facilities. The supply markets for nuclear fuel, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default.

Demand and Supply. The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can depress demand. In addition, in some markets, the supply of electricity can exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants such as our nuclear plants. Conversely, new demand sources such as electrification of transportation could increase demand and change demand patterns.

Retail Competition. Our retail operations compete for customers in a competitive environment, which affects the margins we can earn and the volumes we are able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including us) use their retail operations to hedge generation output.

The impact of sustained low market prices or depressed demand and over-supply could be emphasized given our concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect our ability to reduce debt and provide attractive shareholder returns. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect our financial statements primarily through accelerated depreciation and amortization expenses and one-time charges.

Market Designs. The wholesale markets vary from region to region with distinct rules, practices and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect our business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

Our results were negatively affected by the impacts of COVID-19.

COVID-19 has disrupted economic activity in our markets and negatively affected our results of operations. The estimated impact of COVID-19 to our Net income was approximately $170 million for the year ended December 31, 2020 and is not material for the year ending December 31, 2021. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Significant 2020 and 2021 Transactions and Developments — COVID-19” for additional information. We cannot predict the full extent of the impacts of COVID-19, which will depend on, among other things, the rate, and public perceptions of the effectiveness, of vaccinations and rate of resumption of business activity. In addition, any future widespread pandemic or other local or global health issue could adversely affect customer demand and our ability to operate our generation assets.

We are potentially affected by emerging technologies that could over time affect or transform the energy industry.

Advancements in power generation technology, including commercial and residential solar generation installations and commercial micro turbine installations, are improving the cost-effectiveness of customer self-supply of electricity. Improvements in energy storage technology, including batteries and fuel cells, could also better position customers to meet their around-the-clock electricity requirements. Improvements in energy efficiency of lighting, appliances, equipment and building materials will also affect energy consumption by customers. Changes in power generation, storage, and use technologies could have significant effects on customer behaviors and their energy consumption.

These developments could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and make portions of our generation facilities uneconomic prior to the end of their useful lives. These technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could affect our consolidated financial statements through, among other things, reduced operating revenues, increased operating and maintenance expenses, increased capital expenditures, and potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of our nuclear decommissioning trust funds and employee benefit plan assets, which then could require significant additional funding.

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within our nuclear decommissioning trusts and employee benefit plan trusts. We have significant obligations in these areas and hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below our projected return rates. A decline in the market value of the nuclear decommissioning trust fund investments could increase our funding requirements to decommission our nuclear plants. A decline in the market value of the pension and OPEB plan assets would increase the funding requirements associated with our pension and OPEB plan obligations. Additionally, our pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of the obligations related to the pension and OPEB plans.

We could be negatively affected by unstable capital and credit markets and increased volatility in commodity markets.

We rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs. Disruptions in the capital and credit markets in the United States or abroad could negatively affect our ability to access the capital markets or draw on our bank revolving credit facilities. The banks may not be able to meet their funding commitments to us if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. The inability to access capital markets or credit facilities, and longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, affect our ability to hedge effectively our generation portfolio, require changes to our hedging strategy in order to reduce collateral posting requirements, or require a reduction in discretionary uses of cash. In addition, we have exposure to worldwide financial markets, including Europe, Canada and Asia. Disruptions in these markets could reduce or restrict our ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2020, approximately 20%, 17%, and 16% of our available credit facilities were with European, Canadian and Asian banks, respectively.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be negatively affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that could affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts.

If we were to experience a downgrade in our credit ratings to below investment grade or otherwise fail to satisfy the credit standards in our agreements with our counterparties or regulatory financial requirements, we would be required to provide significant amounts of collateral that could affect our liquidity and we could experience higher borrowing costs.

Our business is subject to credit quality standards that could require market participants to post collateral for their obligations upon a decline in ratings. We are also subject to certain financial requirements under NRC regulations as a result of our operation of nuclear power plants that could require us to provide cash collateral or surety bonds if those requirements are not met. One or both events could affect adversely available liquidity and, in the case of a rating downgrade, borrowing and credit support costs.

If we fail to meet project-specific financing agreement requirements, we could experience an impairment or loss of the financed project.

We have project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have broad remedies, including rights to foreclose against the project assets and related collateral or to force our subsidiaries in the project-specific financings to enter into bankruptcy proceedings. The impact of bankruptcy could result in the impairment of certain project assets.

Our risk management policies cannot fully eliminate the risk associated with our commodity trading activities.

Our asset-based power position as well as our power marketing, fuel procurement and other commodity trading activities expose us to risks of commodity price movements. We buy and sell energy and other products and enter into financial contracts to manage risk and hedge various positions in our power generation portfolio. We are exposed to volatility in financial results for unhedged positions as well as the risk of ineffective hedges. We attempt to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when our policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations could be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power, natural gas and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, we cannot predict the impact that our commodity trading activities and risk management decisions could have on our consolidated financial statements.

Financial performance and load requirements could be negatively affected if we are unable to effectively manage our power portfolio.

A significant portion of our power portfolio is used to provide power under procurement contracts with Exelon's utility subsidiaries and other customers. To the extent portions of the power portfolio are not needed for that purpose, our output is sold in the wholesale power markets. To the extent our power portfolio is not sufficient to meet the requirements of our customers under the related agreements, we must purchase power in the wholesale power markets. Our financial results could be negatively affected if we are unable to meet cost-effectively the load requirements of our customers, manage our power portfolio or effectively address the changes in the wholesale power markets.

The impacts of significant economic downturns could lead to decreased volumes delivered and increased expense for uncollectible customer balances.

The impacts of significant economic downturns on our retail customers, such as less demand for products and services provided by commercial and industrial customers, could result in an increase in the number of uncollectible customer balances and related expense.

We could be negatively affected by the impacts of weather.

Our operations are affected by weather, which affects demand for electricity and natural gas, the price of energy commodities, as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, we could require greater resources to meet our contractual commitments. Extreme weather conditions or storms have affected the availability of generation and its transmission, limiting our ability to source or send power to where it is sold, and have also affected the transportation of natural gas to our generating assets and our ability to supply natural gas to our customers. In addition, drought-like conditions limiting water usage could impact our ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could cause us to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Climate change projections suggest increases to summer temperature and humidity trends, as well as more erratic precipitation and storm patterns over the long-term in the areas where we have generation assets. The frequency in which weather conditions emerge outside the current expected climate norms could contribute to weather-related impacts discussed above.

Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced periodic outages as a result of historically severe cold weather conditions. We estimate a reduction in Net income of approximately $670 million to $820 million for the full year 2021 arising from these market and weather conditions. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant 2020 and 2021 Transactions and Developments — Impacts of February 21 Extreme Weather Event and Texas-based Generating Assets Outages" for additional information.

Long-lived assets and other assets could become impaired.

Long-lived assets — principally, generation assets — represent the single largest asset class on our statement of financial position.

We evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as, but not limited to, the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered.

An impairment would require us to reduce the carrying value of the long-lived asset to fair value through a non-cash charge to expense by the amount of the impairment.

We could incur substantial costs in the event of non-performance by third-parties under indemnification agreements, or when we have guaranteed their performance. We are exposed to other credit risks in the power markets that are beyond our control.

We have entered into various agreements with counterparties that require those counterparties to reimburse us and hold us harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, we could be held responsible for the obligations.

We have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of assets, including several of the Exelon utilities in connection with our absorption of their former generating assets. We could incur substantial costs to fulfill our obligations under these indemnities.

We have issued guarantees of the performance of third parties, which obligate us to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, we could incur substantial cost to fulfill their obligations under these guarantees.

In the bilateral markets, we are exposed to the risk that counterparties that owe us money or are obligated to purchase energy or fuel from us, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, we could be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent amounts, if any, were already paid to the counterparties. In the spot markets, we are exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs. We are also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, our retail sales subject us to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that could be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Risks Related to Regulatory, Legislative and Legal Factors

Federal or state legislative or regulatory actions could negatively affect the scope and functioning of the wholesale markets.

Approximately 70% of our generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Our future results of operations are impacted by (1) FERC's and PJM's level of support for policies that favor the preservation of competitive wholesale power markets and recognize the value of zero-carbon electricity and resiliency and for states' energy objectives and policies and (2) the absence of material changes to market structures that would limit or otherwise negatively affect us. Market rules in other regions could affect us in a similar fashion. We could also be affected by state laws, regulations or initiatives to subsidize existing or new generation.

FERC's requirements for market-based rate authority could pose a risk that we may no longer satisfy FERC's tests for market-based rates. A loss of market-based rate authority would mean that we would sell power at cost-based rates.

Our business is highly regulated and could be negatively affected by regulatory and legislative actions.

Substantial aspects of our business are subject to comprehensive Federal or state regulation and legislation.

Our consolidated financial statements are significantly affected by our sales and purchases of commodities at market-based rates, as opposed to cost-based or other similarly regulated rates and Federal and state regulatory and legislative developments related to emissions, climate change, capacity market mitigation, energy price information, resilience, fuel diversity and RPS. Legislative and regulatory efforts in Illinois, New York and New Jersey to preserve the environmental attributes and reliability benefits of zero-emission nuclear-powered generating facilities through ZEC programs are or could be subject to legal and regulatory challenges and, if overturned, could result in the early retirement of certain of our nuclear plants.

Fundamental changes in regulations or other adverse legislative actions affecting our business would require changes in our business planning models and operations. We cannot predict when or whether legislative and regulatory proposals could become law or what their effect would be.

NRC actions could negatively affect the operations and profitability of our nuclear generating fleet.

Regulatory risk. A change in the Atomic Energy Act or the applicable regulations or licenses could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs. Events at nuclear plants owned by others, as well as those owned by us, could cause the NRC to initiate such actions.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF and the timing of that facility opening, will significantly affect the costs associated with storage of SNF and the ultimate amounts received from the DOE to reimburse us for these costs.

Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect our ability to decommission fully our nuclear units. We cannot predict whether a fee may be established or to what extent, in the future for SNF disposal.

We could be subject to higher costs and/or penalties related to mandatory reliability standards.

We, as a user of the bulk power transmission system, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject us to higher operating costs and/or increased capital expenditures. If we were found in non-compliance with the Federal and state mandatory reliability standards, we could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

We could incur substantial costs to fulfill our obligations related to environmental and other matters.

We are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures, including how we handle air and water emissions, hazardous and solid waste, and activities affecting surface waters, groundwater, and aquatic and other species. Violations of these requirements could subject us to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, we are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances we generated or released. Also, we are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and could be subject to additional proceedings in the future.

We could be negatively affected by federal and state RPS and/or energy conservation legislation, along with energy conservation by customers.

Changes to current state legislation or the development of Federal legislation that requires the use of clean, renewable and alternate fuel sources could significantly impact us. The impact could include reduced use of some of our generating facilities with effects on our revenues and costs.

Federal and state legislation mandating the implementation of energy conservation programs and new energy consumption technologies could cause declines in customer energy consumption and lead to a decline in our revenues. See "We are potentially affected by emerging technologies that could over time affect or transform the energy industry" above.

Our financial performance could be negatively affected by risks arising from our ownership and operation of hydroelectric facilities.

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. We cannot predict whether we will receive all the regulatory approvals for the renewed licenses of our hydroelectric facilities. If FERC does not issue new operating licenses for our hydroelectric facilities or a station cannot be operated through the end of its operating license, our results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. We could also lose revenue and incur increased fuel and purchased power expense to meet our supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, require a substantial increase in capital expenditures, result in increased operating costs or render the project uneconomic. Similar effects could result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by us.

We could be negatively affected by challenges to tax positions taken, tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions.

We are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeal issues related to these tax matters. These judgments include reserves established for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities.

Legal proceedings could result in a negative outcome, which we cannot predict.

We are involved in legal proceedings, claims and litigation arising out of our business operations. The material ones are summarized in Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements and Note 15 — Commitments and Contingencies of the Notes to Interim Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures, result in lost revenue or restrict existing business activities.

We could be subject to adverse publicity and reputational risks, which make us vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences.

We could be the subject of public criticism. Adverse publicity of this nature could render public service commissions and other regulatory and legislative authorities less likely to view energy companies in a favorable light, and could cause those companies, including us, to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent legislative or regulatory requirements.

Risks Related to Operational Factors

We are subject to risks associated with climate change.

We periodically perform analyses to better understand how climate change could affect our facilities and operations. We primarily operate in the Midwest and East Coast of the United States, areas that historically have been prone to various types of severe weather events, and as such we have well-developed response and recovery programs based on these historical events. However, our physical facilities could be placed at greater risk of damage should changes in the global climate impact temperature and weather patterns and result in more intense, frequent and extreme weather events, unprecedented levels of precipitation, sea level rise, increased surface water temperatures, and/or other effects. In addition, changes to the climate may impact levels and patterns of demand for energy and related services, which could affect our operations. Over time, we may need to make additional investments to protect our facilities from physical climate-related risks and/or adapt to changes in operational requirements as a result of climate change.

We also periodically perform analyses of potential pathways to reduce power sector and economy-wide GHG emissions to mitigate climate change. To the extent additional GHG reduction regulation or legislation becomes effective at the Federal and/or state levels, we could incur costs to further limit the GHG emissions from our operations or otherwise comply with applicable requirements. To the extent such additional regulation or legislation does not become effective, the potential competitive advantage offered by our low-carbon emission profile may be reduced.

Our financial performance could be negatively affected by matters arising from our ownership and operation of nuclear facilities.

Nuclear capacity factors. Capacity factors for nuclear generating units significantly affect our results of operations. Lower capacity factors could decrease our revenues and increase operating costs by requiring us to produce additional energy from primarily our fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy our supply obligations to committed third-party sales. These sources generally have higher costs than we incur to produce energy from our nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, could have a significant impact on our results of operations. When refueling outages last longer than anticipated or we experience unplanned outages, capacity factors decrease, and we face lower margins due to higher energy replacement costs and/or lower energy sales and higher operating and maintenance costs.

Nuclear fuel quality. The quality of nuclear fuel utilized by us could affect the efficiency and costs of our operations. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk. Operations at any of our nuclear generation plants could degrade to the point where we must shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense. We could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, we could lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

Further, our nuclear operations produce various types of nuclear waste materials, including SNF. The approval of a national repository for the storage of SNF and the timing of that facility opening, will significantly affect the costs associated with storage of SNF and the ultimate amounts received from the DOE to reimburse us for these costs. Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect our ability to decommission fully our nuclear units. We cannot predict whether a fee may be established or to what extent, in the future for SNF disposal.

If we are required to arrange for the safe and permanent disposal of spent fuel beyond current expectations, this could lead to substantial expense or capital expenditures.

For plants operated but not wholly owned by us, we could also incur liability to the co-owners. For nuclear plants not operated and not wholly owned by us, from which we receive a portion of the plants' output, our results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by us could result in increased regulation and reduced public support for nuclear-fueled energy. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by us.

Nuclear major incident risk and insurance. The consequences of a major incident could be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by us or owned by others, could exceed our resources, including insurance coverage. We are a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for our nuclear operations. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by us. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, whether owned by us or others, could result in increased regulation and reduced public support for nuclear-fueled energy.

As required by the Price-Anderson Act, we carry the maximum available amount of nuclear liability insurance, $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.8 billion limit for a single incident.

Decommissioning obligation and funding. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility.

We recognize as a liability the present value of the estimated future costs to decommission our nuclear facilities. The estimated liability is based on assumptions in the approach and timing of decommissioning the nuclear facilities, estimation of decommissioning costs and Federal and state regulatory requirements. The costs of such decommissioning may substantially exceed such liability, as facts, circumstances or our estimates may change, including changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in Federal or state regulatory requirements on the decommissioning of such facilities, other changes in our estimates or ability to effectively execute on our planned decommissioning activities.

We make contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to us. While we, through PECO, have recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), we have no recourse to collect additional amounts from utility customers for any of our other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that there was an inability to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if we no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units could be negatively affected.

Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to our financial statements could be material. Any changes to the PECO regulatory agreements could impact our ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to our financial statements could be material.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. If the investments held by our NDT funds are not sufficient to fund the decommissioning of our nuclear units, we could be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met.

We are subject to physical security and cybersecurity risks.

We face physical security and cybersecurity risks. Threat sources continue to seek to exploit potential vulnerabilities in the electric generation and natural gas industry associated with protection of sensitive and confidential information, grid infrastructure and other energy infrastructures, and these attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increases the potentially unfavorable impacts of such attacks.

A security breach of our physical assets or information systems or those of our competitors, vendors, business partners and interconnected entities in RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or result in the theft or inappropriate release of certain types of information, including critical infrastructure information, sensitive customer, vendor and employee data, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while we have been, and will likely continue to be, subjected to physical and cyber-attacks, to date we have not directly experienced a material breach or disruption to our network or information systems or our operations. However, as such attacks continue to increase in sophistication and frequency, we may be unable to prevent all such attacks in the future.

If a significant breach were to occur, our reputation could be negatively affected, customer confidence in us or others in the industry could be diminished, or we could be subject to legal claims, loss of revenues, increased costs or operations shutdown. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result.

In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by us or our business operations and could adversely affect our consolidated financial statements.

Our employees, contractors, customers and the general public could be exposed to a risk of injury due to the nature of the energy industry.

Employees and contractors throughout the organization work in, and the general public could be exposed to, potentially dangerous environments near our operations. As a result, employees, contractors and the general public are at some risk for serious injury, including loss of life. These risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events could negatively impact our results of operations, ability to raise capital and future growth.

Our fleet of power plants and the transmission infrastructure to which they are connected could be affected by natural disasters and extreme weather events, which could result in increased costs, including supply chain costs. Natural disasters and other significant events increase our risk that the NRC or other regulatory or legislative bodies could change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological matters. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for our continued operation, particularly the cooling of generating units.

The impact that potential terrorist attacks could have on the industry and on us is uncertain. We face a risk that our operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect our operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cybersecurity of our facilities, which could adversely affect our ability to manage our business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also could result in a decline in energy consumption or interruption of fuel or the supply chain. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

We could be significantly affected by the outbreak of a pandemic. We have plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate our generating assets could be adversely affected.

In addition, we maintain a level of insurance coverage consistent with industry practices against property, casualty and cybersecurity losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Our business is capital intensive, and our assets could require significant expenditures to maintain and are subject to operational failure, which could result in potential liability.

Our business is capital intensive and require significant investments in electric generating facilities. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond our control, and could require significant expenditures to operate efficiently. Our consolidated financial statements could be negatively affected if we were unable to effectively manage our capital projects or raise the necessary capital.

Our performance could be negatively affected if we fail to attract and retain an appropriately qualified workforce.

Certain events, such as the separation transaction, an employee strike, loss of employees, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and increased costs for us. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, could arise. We are particularly affected due to the specialized knowledge required of the technical and support employees for generation operations.

We could make acquisitions or investments in new business initiatives and new markets, which may not be successful or achieve the intended financial results.

We could continue to pursue growth in our existing businesses and markets and further diversification across the competitive energy value chain. This could include investment opportunities in technology and innovation, renewables and other types of generation, and potential expansion of the existing wholesale gas businesses. Such initiatives could involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered during diligence performed prior to launching an initiative or entering a market. Additionally, it is possible that FERC, state public utility commissions or others could impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment.

We may not realize or achieve the anticipated cost savings through the cost management efforts.

Our future financial performance and level of profitability is dependent, in part, on various cost reduction initiatives and may be affected by the separation transaction. We may encounter challenges in executing these cost reduction initiatives and not achieve the intended cost savings.

Risks Related to Our Separation from Exelon

We have no recent history of operating as an independent company, and our historical and pro forma financial information are not necessarily representative of the results that we would have achieved as a separate, publicly traded company and may not be a reliable indicator of our future results.

The historical information about Generation in this information statement refers to the business of Generation as integrated with Exelon. Additionally, the pro forma financial information included in this information statement is derived from our historical financial information and (i) gives effect to the separation and (ii) reflects our anticipated post-separation capital structure. Accordingly, the historical and pro forma financial information does not necessarily reflect the financial condition, results of operations or cash flows that we would have achieved as a separate, publicly traded company during the periods presented or those that we may achieve in the future primarily as a result of the factors described below:

- Prior to the distribution, our business has been operated by Exelon as part of its broader corporate organization, rather than as an independent company. One of Exelon’s affiliates has performed various corporate functions for us, including legal, treasury, accounting, auditing, human resources, investor relations, and finance. Our historical and pro forma financial results reflect allocations of corporate expenses from Exelon for such functions, which may be less than the expenses we would have incurred had we operated as a separate, publicly traded company.
- Currently, our business is integrated with the other businesses of Exelon. Historically, we have shared economies of scope and scale in costs, employees and vendor relationships. While we have

sought to minimize the impact on us when separating these arrangements, there is no guarantee these arrangements will continue to capture these benefits in the future.

- As a current part of Exelon, we take advantage of Exelon's overall size and scope to obtain more advantageous procurement terms. After the distribution, as a standalone company, we may be unable to obtain similar arrangements to the same extent as Exelon did, or on terms as favorable as those Exelon obtained, prior to completion of the distribution.
- After the completion of the distribution, the cost of capital for our business may be higher than our cost of capital prior to the distribution.

Other significant changes may occur in our cost structure, management, financing and business operations as a result of operating as a company separate from Exelon. For additional information about the past financial performance of our business and the basis of presentation of the historical consolidated financial statements and the unaudited pro forma condensed consolidated financial statements of our business, see "Unaudited Pro Forma Condensed Consolidated Financial Information," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and accompanying notes included elsewhere in this information statement.

Following the separation, our financial profile will change, and we will be a smaller, less diversified company than Exelon prior to the separation.

The separation will result in us and Exelon being smaller, less diversified companies with more limited businesses concentrated in their respective industries. As a result, we may be more vulnerable to changing market conditions, which could have a material adverse effect on our business, financial condition and results of operations. In addition, the diversification of our revenues, costs, and cash flows will diminish as a standalone company, such that our results of operations, cash flows, working capital and financing requirements may be subject to increased volatility and our ability to fund capital expenditures and investments, pay dividends and service debt may be diminished.

We may not achieve some or all of the expected benefits of the separation, and the separation may materially adversely affect our business.

As discussed below under "The Separation — Reasons for the Separation," we believe that the separation is in the best interest of our shareholders. However, we may not be able to achieve the full strategic and financial benefits expected to result from the separation, or such benefits may be delayed or not occur at all.

If we fail to achieve some or all of the benefits expected to result from the separation, or if such benefits are delayed, it could have a material adverse effect on our competitive position, business, financial condition, results of operations and cash flows.

Exelon's plan to separate into two independent, publicly traded companies is subject to various risks and uncertainties and may not be completed in accordance with the expected plans or anticipated timeline, or at all, and will involve significant time and expense, which could disrupt or adversely affect our business.

In February 2021, Exelon announced its plan to separate into two independent, publicly traded companies. The separation is subject to the satisfaction of certain conditions (or waiver by Exelon in its sole and absolute discretion), including final approval by Exelon's board of directors of the final terms of the separation and certain other conditions. Furthermore, the separation is complex in nature, and unanticipated developments or changes, including changes in the law, the macroeconomic environment, competitive conditions of Exelon's markets, regulatory approvals or clearances, the uncertainty of the financial markets and challenges in executing the separation, could delay or prevent the completion of the proposed separation, or cause the separation to occur on terms or conditions that are different or less favorable than expected. Additionally, Exelon's board of directors, in its sole and absolute discretion, may decide not to proceed with the separation at any time prior to the distribution date.

The process of completing the proposed separation has been and is expected to continue to be time-consuming and involves significant costs and expenses. The separation costs may be significantly higher than what we currently anticipate and may not yield a discernible benefit if the separation is not completed or is not well executed, or if the expected benefits of the separation are not realized. Executing the proposed separation will also require significant amounts of management's time and effort. Other challenges associated with effectively executing the separation include attracting, retaining and motivating employees during the pendency of the separation and following its completion; addressing disruptions to our supply chain and other operations resulting from separating Exelon into two independent companies; and separating Exelon's information systems.

Until the separation occurs, Exelon has sole discretion to change the terms of the separation in ways that may be unfavorable to us.

Until the separation occurs, we will be a wholly owned subsidiary of Exelon. Accordingly, Exelon will effectively have the sole and absolute discretion to determine and change the terms of the separation, including the establishment of the record date for the distribution and the distribution date. These changes could be unfavorable to us.

In addition, Exelon may decide at any time not to proceed with the separation and distribution if at any time Exelon's board of directors determines, in its sole and absolute discretion, that the distribution of our common stock or the terms thereof are not in the best interests of Exelon and its shareholders or that legal, market or regulatory conditions or other circumstances are such that the separation and distribution are no longer advisable at that time. If Exelon's board of directors determines to cancel the separation and distribution, Exelon's shareholders will not receive any distribution of our common stock and Exelon will be under no obligation whatsoever to its shareholders to distribute those shares.

The terms we will receive in our agreements with Exelon could be less beneficial than the terms we may have otherwise received from unaffiliated third parties.

The agreements we will enter into with Exelon in connection with the separation, including the separation agreement, a tax matters agreement, an employee matters agreement, and a transition services agreement, were prepared in the context of the separation while we were still a wholly owned subsidiary of Exelon. Accordingly, during the period in which the terms of those agreements were prepared, we did not have an independent board of directors or a management team that was independent of Exelon. As a result, the terms of those agreements may not reflect terms that would have resulted from negotiations between unaffiliated third parties. See "Certain Relationships and Related Party Transactions."

Exelon may fail to perform under various transaction agreements that will be executed as part of the separation, which could cause us to incur expenses or losses we would not otherwise incur.

In connection with the separation and prior to the distribution, we and Exelon will enter into the separation agreement and will also enter into various other agreements, including a tax matters agreement, an employee matters agreement, and a transition services agreement. The separation agreement, the tax matters agreement and the employee matters agreement will determine the allocation of assets and liabilities between the companies following the separation for those respective areas and will include any necessary indemnifications related to liabilities and obligations. We will rely on Exelon to satisfy its performance and payment obligations under these agreements. If Exelon is unable or unwilling to satisfy its obligations under these agreements, including its indemnification obligations, we could incur operational difficulties and/or losses.

In connection with the separation into two public companies, each of Exelon and we will indemnify each other for certain liabilities. If we are required to pay under these indemnities to Exelon, our financial results could be negatively impacted. The Exelon indemnities may not be sufficient to hold us harmless from the full amount of liabilities for which Exelon will be allocated responsibility, and Exelon may not be able to satisfy its indemnification obligations in the future.

Pursuant to the separation agreement and certain other agreements between Exelon and us, each party will agree to indemnify the other for certain liabilities, in each case for uncapped amounts, as discussed further in the section entitled "Certain Relationships and Related Party Transactions — Agreements with Exelon Related to the Separation — Separation Agreement" of this information statement. Indemnities that we may be required to provide Exelon are not subject to any cap, may be significant and could negatively impact our business. Third parties could also seek to hold us responsible for any of the liabilities that Exelon has agreed to retain. Any amounts we are required to pay pursuant to these indemnification obligations and other liabilities could require us to divert cash that would otherwise have been used in furtherance of our operating business. Further, the indemnities from Exelon for our benefit may not be sufficient to protect us against the full amount of such liabilities, and Exelon may not be able to fully satisfy its indemnification obligations.

Moreover, even if we ultimately succeed in recovering from Exelon any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves. Each of these risks could negatively affect our business, results of operations and financial condition.

We may fail to have necessary systems and services in place when certain of the transaction agreements expire.

If we do not have in place our own systems and services, or if we do not have agreements with other providers of these services once certain separation transaction agreements expire, we may not be able to operate our business effectively, and our profitability may decline. We are in the process of creating our own, or engaging third parties to provide, systems and services to replace many of the systems and services that Exelon currently provides to us. We may incur temporary interruptions in business operations if we cannot transition effectively from Exelon’s existing operating systems, databases and programming languages that support these functions to our own systems. Our failure to implement the new systems and transition our data successfully and cost-effectively could disrupt our business operations and have a material adverse effect on our profitability. In addition, our costs for the operation of these systems may be higher than the amounts reflected in our historical combined financial statements.

If the distribution, together with certain related transactions, fails to qualify as a tax-free transaction for U.S. federal income tax purposes, then we, Exelon and Exelon’s shareholders could be subject to significant tax liability or tax indemnity obligations.

It is a condition to the completion of the separation that Exelon receive the IRS Ruling and an opinion from its counsel, Sidley Austin LLP, together substantially to the effect that the distribution, together with certain related transactions, will qualify as a tax-free reorganization under Sections 355 and 368(a)(1)(D) of the IRC.

Exelon has received the IRS Ruling. Although a private letter ruling from the IRS is generally binding on the IRS, the IRS Ruling will rely on certain facts, assumptions, representations and undertakings from Exelon and us regarding the past and future conduct of Exelon’s and our business, among other matters. Moreover, the IRS Ruling is not a comprehensive ruling regarding all aspects of the U.S. federal income tax consequences of the separation and distribution. The opinion of counsel, if received from Exelon’s counsel, will also rely on certain facts, assumptions and covenants, as described therein, as well as on the continued validity of the IRS Ruling. In addition, Exelon’s counsel’s ability to provide an opinion will depend on the absence of changes in existing facts or law between the date of this information statement and the closing date of the separation. The opinion of counsel will not be binding on the IRS or the courts, and the IRS or the courts may not agree with such opinion.

Notwithstanding the IRS Ruling and opinion of counsel, the IRS could determine on audit that the distribution or any of certain related transactions is taxable if it determines that any of the facts, assumptions, representations or undertakings upon which such ruling and opinion rely are not correct or have been violated or if it disagrees with the conclusions in the opinion that are not covered by the IRS Ruling, or for other reasons, including as a result of certain significant changes in the stock ownership of Exelon or us after the distribution. If the distribution or certain related transactions is ultimately determined to be taxable, the distribution could be treated as a taxable dividend to you for U.S. federal income tax purposes, and you could incur significant U.S. federal income tax liability. In addition, Exelon and/or we could incur significant U.S. federal income tax liabilities or tax indemnification obligations, whether under applicable law or the tax matters agreement that we will enter into with Exelon, if it is ultimately determined that certain related transactions were undertaken in anticipation of the distribution.

We may not be able to engage in desirable capital-raising or strategic transactions following the separation.

Under current U.S. federal income tax law, a spin-off that otherwise qualifies for tax-free treatment can be rendered taxable to the parent corporation and its shareholders as a result of certain post-spin-off transactions, including certain acquisitions of shares or assets of the spun-off corporation. To preserve the tax-free treatment of the distribution, and in addition to potential tax indemnity obligations, we will agree to certain limitations or prohibitions in the tax matters agreement that may prohibit us, for the two-year period following the distribution and except in specific circumstances, from, among other things:

- entering into any transaction pursuant to which all or a portion of the shares of our stock, or substantially all of our assets, would be acquired, whether by merger or otherwise;
- issuing equity securities beyond certain thresholds;
- repurchasing shares of our stock other than in certain open-market transactions; and
- ceasing to actively conduct our business.

The tax matters agreement will also prohibit us from taking or failing to take any other action that would prevent the distribution and certain related transactions from qualifying as a transaction that is generally tax-free for U.S. federal income tax purposes under Sections 355 and 368(a)(1)(D) of the IRC. These restrictions may limit our ability to pursue certain equity issuances, strategic transactions, repurchases or other transactions that we may believe to be in the best interests of our shareholders or that might increase the value of our business. For more information, see the sections entitled “Certain Relationships and Related Party Transactions — Agreements with Exelon Related to the Separation — Tax Matters Agreement” and “The Separation — Material U.S. Federal Income Tax Consequences of the Separation.”

The transfer to us of certain contracts may require the consents or approvals of, or provide other rights to, third parties. If such consents or approvals are not obtained, we may not be entitled to the benefit of such contracts, which could increase our expenses or otherwise harm our business and financial performance.

In some circumstances, we and Exelon are joint beneficiaries of contracts, and we and Exelon may need the consent of third parties in order to split or separate the existing contracts or the relevant portion of the existing contracts between us and Exelon.

Some parties may use consent requirements or other rights to seek to terminate contracts or obtain more favorable contractual terms from us, which, for example, could take the form of adverse price changes, require us to expend additional resources in order to obtain the services or assets previously provided under the contract, or require us to seek arrangements with new third parties or obtain letters of credit or other forms of credit support. If we are unable to obtain required consents or approvals, we may be unable to obtain the contractual commitments that are intended to be allocated to us as part of our separation from Exelon, and we may be required to seek alternative arrangements to obtain services and assets which may be more costly and/or of lower quality. The termination or modification of these contracts or the failure to timely complete the transfer or separation of these contracts could negatively impact our business, financial condition, results of operations and cash flows.

Risks Related to Our Common Stock

We cannot be certain that an active trading market for our common stock will develop or be sustained after the separation, and following the separation, our stock price may fluctuate significantly.

A public market for our common stock does not currently exist. We anticipate that on or prior to the record date for the distribution, trading of shares of our common stock will begin on a “when-issued” basis and will continue through the distribution date. However, we cannot guarantee that an active trading market will develop or be sustained for our common stock after the separation. If an active trading market does not develop, you may have difficulty selling your shares of common stock at an attractive price, or at all. In addition, we cannot predict the prices at which shares of our common stock may trade after the separation.

Similarly, we cannot predict the effect of the separation on the trading prices of our common stock. After the distribution, Exelon's common stock will continue to be listed and traded on NASDAQ under the symbol "EXC." Subject to the consummation of the separation, we expect our common stock to be listed and traded on NASDAQ under the symbol "CEG." The combined trading prices of the shares of our common stock and Exelon common stock after the separation, as adjusted for any changes in the combined capitalization of these companies, may not be equal to or greater than the trading prices of Exelon's common stock prior to the separation. Until the market has fully evaluated the business of Exelon without our business, and fully evaluated us, the price at which Exelon's or our common stock trades may fluctuate significantly.

Many factors could cause the market price of our common stock to rise and fall, including the following:

- our business profile and market capitalization may not fit the investment objectives of Exelon's current shareholders, causing a shift in our investor base, and our common stock may not be included in some indices in which Exelon's common stock is included, causing certain holders to sell their common stock;
- our announcements or our competitors' announcements regarding new products or services, enhancements, significant contracts, acquisitions or strategic investments;
- fluctuations in our quarterly or annual financial results or the quarterly or annual financial results of companies perceived to be similar to us;
- the failure of securities analysts to cover our common stock after the separation;
- changes in earnings estimates or recommendations by securities analysts or our ability to meet those estimates;
- the operating and stock price performance of other comparable companies;
- investors' general perception of us and our industry;
- changes to the regulatory and legal environment under which we operate;
- changes in general economic and market conditions;
- changes in industry conditions; and
- the other factors described in this "Risk Factors" section and elsewhere in this information statement.

In addition, if the market for stocks in our industry, or the stock market in general, experiences a loss of investor confidence, the trading price of our common stock could decline for reasons unrelated to our business, financial condition or results of operations. If any of the foregoing occurs, it could cause our stock price to fall and may expose us to lawsuits that, even if successfully defended, could be costly to defend and a distraction to management.

A significant number of shares of our common stock may be sold following the distribution, which may cause our stock price to decline.

Any sales of substantial amounts of our common stock in the public market or the perception that such sales might occur, in connection with the distribution or otherwise, may cause the market price of our common stock to decline. Upon completion of the distribution, we expect that we will have an aggregate of approximately 326.5 million shares of our common stock issued and outstanding (based on 979.5 million shares of Exelon common stock outstanding as of December 31, 2021). Shares distributed to Exelon shareholders in the separation will generally be freely tradeable without restriction or further registration under the U.S. Securities Act of 1933, as amended (the "*Securities Act*"), except for shares owned by one of our "affiliates," as that term is defined in Rule 405 under the Securities Act.

We are unable to predict whether large amounts of our common stock will be sold in the open market following the distribution. We are also unable to predict whether a sufficient number of buyers of our common stock to meet the demand to sell shares of our common stock at attractive prices would exist at that time.

Your percentage of ownership in us may be diluted in the future.

In the future, your percentage ownership in us may be diluted because of equity issuances for acquisitions, capital market transactions or otherwise, including any equity awards that we will grant to our directors, officers and employees. Our employees will have stock-based awards that correspond to shares of our common stock after the distribution as a result of conversion of their Exelon stock-based awards. We anticipate that the compensation committee of our board of directors may grant additional stock-based awards to our employees after the distribution. Those awards will have a dilutive effect on the number of our shares outstanding, and therefore on our earnings per share, which could adversely affect the market price of our common stock. From time to time, we will issue additional stock-based awards to our employees under our employee benefits plans.

As a holding company, we are dependent on upstream cash flows from our subsidiaries for the payment of dividends on our common stock.

As a holding company, we have no operations of our own, and our ability to pay dividends on our common stock is dependent on the earnings and cash flows of our operating subsidiaries and their ability to pay upstream dividends or to repay funds to us. Our subsidiaries have financial obligations that must be satisfied before funding us. These obligations include debt service and obligations to trade creditors, among others. Our subsidiaries are also subject to contractual restrictions on the payment of dividends. For more information, see the sections entitled “Dividend Policy” and “Description of Certain Indebtedness — Revolving Credit Facility.”

Anti-takeover provisions could enable us to resist a takeover attempt by a third party.

Our amended and restated articles of incorporation and amended and restated bylaws will contain, and Pennsylvania law contains, provisions that are intended to deter coercive takeover practices and inadequate takeover bids by making such practices or bids unacceptably expensive to the bidder and to encourage prospective acquirers to negotiate with our board of directors rather than to attempt a hostile takeover.

We believe these provisions will protect our shareholders from coercive or otherwise unfair takeover tactics by requiring potential acquirers to negotiate with our board of directors and by providing our board of directors with more time to assess any acquisition proposal. These provisions are not intended to make us immune from takeovers; however, these provisions will apply even if the offer may be considered beneficial by some shareholders and could delay or prevent an acquisition that our board of directors determines is not in the best interests of us and our shareholders. These provisions may also prevent or discourage attempts to remove and replace incumbent directors. See “Description of Common Stock — Certain Anti-Takeover Provisions.”

In addition, an acquisition or further issuance of our stock could trigger the application of Section 355(e) of the IRC, causing the distribution to be taxable to Exelon. For a discussion of Section 355(e) of the IRC, see “The Separation — Material U.S. Federal Income Tax Consequences of the Separation.” Under the tax matters agreement, we would be required to indemnify Exelon for the resulting tax, and this indemnity obligation might discourage, delay or prevent a change of control that our shareholders may consider favorable.

Our amended and restated articles of incorporation will designate the state courts of the Commonwealth of Pennsylvania (or if such state courts do not have jurisdiction, the federal district courts located within the Commonwealth of Pennsylvania) as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our shareholders, and the United States federal district courts as the exclusive forum for claims under the Securities Act, which could limit our shareholders’ ability to obtain what such shareholders believe to be a favorable judicial forum for disputes with us or our directors, officers or employees.

Our amended and restated articles of incorporation will provide that, unless our board of directors consents in writing to an alternative forum, a state court within the Commonwealth of Pennsylvania (or if no such state court has jurisdiction, a federal district court within the Commonwealth of Pennsylvania) will be the sole and exclusive forum for (1) any derivative action or proceeding brought on behalf of the

Company (including any derivative suit brought to enforce any liability or duty created by the Exchange Act), (2) any action asserting a claim of breach of a fiduciary duty owed by any current or former director, officer or employee of the Company to the Company or its shareholders, (3) any action asserting a claim against the Company or any of its directors, officers or employees arising pursuant to any provision of the Pennsylvania Business Corporation Law (the "*PBCL*") or as to which the PBCL confers jurisdiction on the Pennsylvania Courts of Common Pleas or the amended and restated articles of incorporation or amended and restated bylaws or (4) any action asserting a claim against the Company or any of its directors, officers or employees governed by the internal affairs doctrine. The amended and restated articles of incorporation will also provide that unless our board of directors consents in writing to an alternative forum, the federal district courts of the United States of America will be the sole and exclusive forum for the resolution of any action asserting a cause of action arising under the Securities Act.

Although the amended and restated articles of incorporation will include these exclusive forum provisions, it is possible that a court could rule that these provisions are inapplicable or unenforceable. Our exclusive forum provision will apply to derivative suits brought to enforce any liability or duty created by the Exchange Act, and investors cannot waive compliance with the federal securities laws and the rules and regulations thereunder. These exclusive provisions may limit a shareholder's ability to bring a claim in a judicial forum that the shareholder believes to be favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits. It is possible that a court could find these exclusive forum provisions inapplicable or unenforceable with respect to one or more of the specified types of actions or proceedings, and we may incur additional costs associated with resolving such matters in other jurisdictions, which could materially adversely affect our business, financial condition and results of operations and result in a diversion of the time and resources of our management and board of directors.

The combined post-separation value of share of our common stock and one share of Exelon common stock may not equal or exceed the pre-distribution value of one share of Exelon common stock.

As a result of the separation, we expect the trading price of shares of Exelon common stock immediately following the separation to be different from the "regular-way" trading price of Exelon common shares immediately prior to the separation because the trading price will no longer reflect the value of our businesses. There can be no assurance that the aggregate market value of share of our common stock and one share of Exelon common stock following the separation will be higher than, lower than or the same as the market value of a share of Exelon common stock if the separation did not occur.

THE SEPARATION

Background

On February 21, 2021, Exelon's board of directors unanimously authorized management to pursue a plan to separate the Company from Exelon. The board considered a sale of Exelon's competitive generation and customer-facing business as a possible alternative, but ultimately decided that a separation was the most efficient way to separate its businesses in a manner intended to enhance long-term value to Exelon's shareholders.

The Exelon board regularly reviews the businesses that comprise Exelon to confirm that its business mix and portfolio are in the best interests of Exelon and its shareholders. In the more recent reviews leading to the February decision, the board determined that separating Exelon's regulated utility businesses from its competitive generation and customer-facing businesses would improve strategic and management focus and could unlock shareholder value. In reaching its decision to pursue the separation, the board considered a possible sale of competitive generation and customer-facing businesses to third parties. With the assistance of advisors, that consideration included an evaluation of the potential tax costs of a sale, the effort and distractions associated with a sale process, the likelihood of a complete disposition to a single buyer versus a partial disposition to multiple buyers and associated impacts upon generation operating performance and efficiencies, and possible regulatory hurdles due to potential overlapping markets served by potential buyers. Those factors made a sale alternative less attractive as compared to the separation alternative, which, as described under "Reasons for the Separation" below, achieved a number of objectives that the board felt accomplished better results for Exelon's shareholders. The board ultimately determined not to engage in a sale process and negotiations as it concluded that a separation was the most efficient way to separate Exelon's businesses in a manner intended to enhance long term value to Exelon's shareholders.

As a result of that separation, the Company will become a separate, publicly-traded company, and Exelon will have no continuing stock ownership interest in the Company. Prior to the separation, Exelon will effect several internal transactions. See "— Manner of Effecting the Separation — Internal Transactions."

To complete the separation, Exelon will, following the completion of the internal transactions, distribute to Exelon shareholders all of the outstanding shares of our common stock. The distribution will occur on the distribution date, which is expected to be February 1, 2022. Each holder of Exelon common stock will receive one share of our common stock for every three shares of Exelon common stock held at 5:00 p.m. Eastern Time, on January 20, 2022, the record date. After completion of the distribution:

- We will be a publicly-traded company (NASDAQ: CEG) and, through Generation, will own Exelon's competitive generation and customer-facing energy businesses; and
- Exelon will continue to be a publicly-traded company (NASDAQ: EXC) and will continue to own and conduct its regulated electric distribution and transmission and gas distribution businesses.

Each holder of Exelon common stock will continue to hold his, her or its shares in Exelon. No vote of Exelon shareholders is required or is being sought in connection with the separation, and Exelon shareholders will not have any appraisal rights in connection with the separation.

The distribution is subject to the satisfaction or waiver of certain conditions. In addition, until the distribution has occurred, Exelon's board of directors has the right not to proceed with the distribution, even if all of the conditions are satisfied. See "— Conditions to the Distribution."

Reasons for the Separation

Exelon is comprised of six regulated utility operating companies that together serve more than 10 million customers, and Generation, an electricity producer and a competitive energy retailer. The utility operating companies provide electricity transmission and distribution and gas distribution services within relatively defined geographic areas under service terms, conditions and rates that are regulated by public utility commissions based on each utility's investment in plant, property and equipment, referred to as rate base, and their operating costs. Generation generates electricity primarily from nuclear generating plants and sells electricity and natural gas to wholesale and retail customers within a broad geographic area under service terms, conditions and prices determined by competitive market forces.

The Exelon board of directors believes that the separation of the competitive generation and customer-facing businesses from the regulated utility businesses is in the best interest of Exelon and its shareholders for a number of reasons, including:

- *Direct investment identity* — Exelon's board of directors believes that Exelon's regulated utility businesses and our competitive businesses appeal to different types of investors with different industry focuses, investment goals and risk profiles. The utility and competitive businesses have different investment and business characteristics, including different opportunities for growth, capital structures, business models and financial returns. The separation will better position each business within its peer set and will support business strategies tailored to distinct investment profiles and meeting unique customer needs.
- *More specialized strategic focus* — The separation will allow each company to more effectively pursue its own distinct operating priorities and strategies and will enable the management of both companies to respond to changes in the industry in which operates, pursue separate opportunities for long-term growth and profitability, without taking into account potentially conflicting or competing needs and objectives of two disparate businesses operating in a single company. This ability will unlock strategic flexibility for each company to focus on its core business strategies to better meet evolving customer needs and stakeholder goals. As a standalone company, the Company may be able to pursue investments or acquisitions in the competitive energy infrastructure space that Exelon's current shareholders would not find attractive as it would increase Exelon's exposure to non-regulated businesses.
- *More efficient allocation of capital* — The separation will permit each company to concentrate its financial resources solely on its own operations, providing greater flexibility to invest capital in its business in a time and manner appropriate for its distinct strategy and business needs, all of which will facilitate a more efficient allocation of capital
- *Allows each business to maintain risk profiles more appropriate for their shareholders* — The competitive generation and customer-facing energy businesses of Exelon are exposed to certain market risks, including, in the near term, the volatility in the price of power, natural gas and other commodities. As operated today, the competitive businesses are substantially hedged in the near-term against certain commodity risks, because commodity price movements could adversely affect Exelon's near-term earnings, cash flows and credit ratings if Exelon were substantially unhedged. The Company will be committed to disciplined risk-mitigation policies, including a ratable hedging strategy, and Exelon's board of directors believes that separating the Company from the regulated utilities of Exelon will give our management further flexibility to manage our risk.
- *Aligns management incentives* — The separation will permit the creation of equity-based incentive compensation programs for each of the companies that is expected to reflect more closely the efforts and performance of each company's management and will allow each company to better recruit, retain and motivate employees pursuant to compensation policies that are appropriate for their respective lines of business.

For information about risks related to the separation, see the "Risk Factors — Risks Relating to Our Separation from Exelon" beginning on page 37 of this information statement. Neither Exelon nor we can assure you that, following the separation, any of the benefits described above or otherwise will be realized to the extent anticipated or at all.

Manner of Effecting the Separation

The general terms and conditions relating to the separation will be set forth in a separation agreement between us and Exelon, which we refer to as the separation agreement.

Internal Transactions

We were incorporated as a Pennsylvania corporation on June 15, 2021 for the purpose of holding Generation and its competitive generation and customer-facing energy businesses.

Immediately prior to the separation:

- Generation will repay to Exelon an intercompany loan expected to have an outstanding principal amount of $258 million.
- Exelon will contribute its equity ownership in Generation, including its subsidiaries, to us.
- Exelon will contribute $1.75 billion in cash to us.

Distribution of Shares of Our Common Stock

Under the separation agreement, the distribution will be effective as of 12:01 a.m. Eastern time, on February 1, 2022, the distribution date. As a result of the separation, on the distribution date, each holder of Exelon common stock will receive one share of our common stock for every three shares of Exelon common stock that he, she or it owns as of 5:00 p.m. Eastern time, on January 20, 2022, the record date. The actual number of shares to be distributed will be determined based on the number of shares of Exelon common stock outstanding as of the record date. The shares of our common stock to be distributed by Exelon will constitute all of the issued and outstanding shares of our common stock held by Exelon immediately prior to the distribution.

On the distribution date, Exelon will release the shares of our common stock to the Distribution Agent to distribute to Exelon shareholders. The Distribution Agent will credit the shares of our common stock to the book-entry accounts of Exelon shareholders established to hold their shares of our common stock. The Distribution Agent will send these shareholders a statement reflecting their ownership of our common stock. Book-entry refers to a method of recording stock ownership in our records in which no physical certificates are issued. For shareholders who own Exelon common stock through a broker or other nominee, their shares of our common stock will be credited to these shareholders' accounts by the broker or other nominee. It may take the Distribution Agent up to two weeks to distribute shares of our common stock to Exelon shareholders or to their bank or brokerage firm electronically by way of direct registration in book-entry form. Trading of our stock will not be affected by this delay in distribution by the Distribution Agent.

Exelon shareholders will not be required to make any payment or surrender or exchange their shares of Exelon common stock or take any other action to receive their shares of our common stock.

No vote of Exelon shareholders is required or sought in connection with the separation. Exelon shareholders have no appraisal rights in connection with the separation.

Treatment of Fractional Shares

The Distribution Agent will not distribute any fractional shares of our common stock to Exelon shareholders. Instead, as soon as practicable on or after the distribution date, the Distribution Agent will aggregate fractional shares of our common stock to which Exelon shareholders of record would otherwise be entitled into whole shares, sell them in the open market at the prevailing market prices and then distribute the aggregate net sale proceeds ratably to Exelon shareholders who would otherwise have been entitled to receive fractional shares of our common stock. The amount of this payment will depend on the prices at which the Distribution Agent sells the aggregated fractional shares of our common stock in the open market shortly after the distribution date and will be reduced by any amount required to be withheld for tax purposes and any brokerage fees and other expenses incurred in connection with these sales of fractional shares. Receipt of the proceeds from these sales generally will result in a taxable gain or loss to those Exelon shareholders. Each shareholder entitled to receive cash proceeds from these shares should consult his, her or its own tax advisor as to the shareholder's particular circumstances. The tax consequences of the distribution are described in more detail under "— Material U.S. Federal Income Tax Consequences of the Separation."

Transaction and Separation Costs

Exelon will assume all costs incurred in connection with the consummation of the transaction. We currently estimate that the one-time separation costs we will incur, primarily employee-related costs such as recruitment expenses, costs to establish certain stand-alone functions and information technology systems, professional services fees and other separation-related costs during our transition to being a stand-alone public company, will be approximately $400 million.

Material U.S. Federal Income Tax Consequences of the Separation

The following is a summary of the material U.S. federal income tax consequences to the U.S. Holders (as defined below) of shares of Exelon common stock in connection with the distribution and certain related transactions. This summary is based on the IRC, the Treasury regulations promulgated thereunder, and judicial and administrative interpretations thereof, all as in effect as of the date of this information statement, and all of which are subject to differing interpretations and may change at any time, possibly with retroactive effect. Any such change could affect the tax consequences described below. This summary assumes that the separation will be consummated in accordance with the separation agreement and as described in this information statement.

This summary is limited to holders of shares of Exelon common stock that are U.S. Holders, as defined immediately below. For purposes of this summary, a U.S. Holder is a beneficial owner of Exelon common stock that is, for U.S. federal income tax purposes:

- an individual who is a citizen or a resident of the United States;
- a corporation, or other entity treated as a corporation for U.S. federal income tax purposes, created or organized under the laws of the United States or any state thereof or the District of Columbia;
- an estate, the income of which is subject to U.S. federal income taxation regardless of its source; or
- a trust (i) with respect to which a court within the United States is able to exercise primary jurisdiction over its administration and one or more U.S. persons (within the meaning of Section 7701(a)(30) of the IRC) have the authority to control all of its substantial decisions, or (ii) that has a valid election in place under applicable Treasury regulations to be treated as a U.S. person.

This summary does not discuss all tax considerations that may be relevant to Exelon shareholders in light of their particular circumstances, nor does it address the consequences to Exelon shareholders subject to special treatment under the U.S. federal income tax laws, including:

- a financial institution, regulated investment company or insurance company;
- a tax-exempt organization;
- a dealer or broker in securities, commodities or foreign currencies;
- a holder that holds Exelon common stock as part of a hedge, appreciated financial position, straddle, conversion or other risk reduction transaction;
- a holder that holds Exelon common stock in a tax-deferred account, such as an individual retirement account; or
- a holder that acquired Exelon common stock pursuant to the exercise of options or similar derivative securities or otherwise as compensation.

This summary also does not address the U.S. federal income tax consequences to Exelon shareholders who do not hold shares of Exelon common stock as a capital asset. Moreover, this summary does not address any state, local or non-U.S. tax consequences, or any federal tax other than U.S. federal income tax consequences (such as estate or gift tax consequences or the Medicare tax on certain investment income).

If a partnership (or any other entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds shares of Exelon common stock, the tax treatment of a partner in that partnership generally will depend on the status of the partner and the activities of the partner and the partnership. Such a partner or partnership is urged to consult its tax advisor as to the tax consequences of the separation.

WE URGE YOU TO CONSULT WITH YOUR TAX ADVISOR AS TO THE SPECIFIC U.S. FEDERAL, STATE AND LOCAL, AND NON-U.S. TAX CONSEQUENCES OF THE SEPARATION IN LIGHT OF YOUR PARTICULAR CIRCUMSTANCES.

Treatment of the Separation

Completion of the separation is conditioned upon Exelon's receipt of the IRS Ruling and an opinion from its counsel, Sidley Austin LLP, together substantially to the effect that the distribution, together with certain related transactions, will qualify as a tax-free reorganization under Sections 355 and 368(a)(1)(D) of the IRC.

Exelon has received the IRS Ruling. Although a private letter ruling from the IRS is generally binding on the IRS, the IRS Ruling relies on certain facts, assumptions, representations and undertakings from Exelon and us regarding the past and future conduct of Exelon's and our business, among other matters. Moreover, the IRS Ruling is not a comprehensive ruling regarding all aspects of the U.S. federal income tax consequences of the separation and distribution. The opinion of counsel, if received from Exelon's counsel, will also rely on certain facts, assumptions and covenants, as described therein, as well as on the continued validity of the IRS Ruling. In addition, Exelon's counsel's ability to provide an opinion will depend on the absence of changes in existing facts or law between the date of this information statement and the closing date of the separation. The opinion of counsel will not be binding on the IRS or the courts, and the IRS or the courts may not agree with such opinion.

Notwithstanding the IRS Ruling and opinion of counsel, the IRS could determine on audit that the distribution or any of certain related transactions is taxable if it determines that any of the facts, assumptions, representations or undertakings upon which such ruling and opinion rely are not correct or have been violated or if it disagrees with the conclusions in the opinion that are not covered by the IRS Ruling, or for other reasons, including as a result of certain significant changes in the stock ownership of Exelon or us after the distribution. If, notwithstanding the IRS Ruling and the opinion of counsel, it is ultimately determined that the distribution, together with certain related transactions, do not qualify as tax-free under Sections 355 and 368(a)(1)(D) of the IRC, then Exelon or we could incur significant U.S. federal income tax liabilities attributable to the separation and distribution. In addition, if the distribution does not qualify as tax-free under Section 355 of the Code, each Exelon shareholder that receives shares of our common stock in the distribution would be treated as receiving a distribution in an amount equal to the fair market value of our common stock that was distributed to the shareholder, which would generally be taxed as a dividend to the extent of the shareholder's *pro rata* share of Exelon's current and accumulated earnings and profits, including Exelon's taxable gain, if any, on the separation, then treated as a non-taxable return of capital to the extent of the shareholder's basis in the Exelon stock and thereafter treated as capital gain from the sale or exchange of Exelon common stock. Under current U.S. federal income tax law, certain non-corporation citizens or residents of the United States (including individuals) currently are subject to U.S. federal income tax on dividends (assuming certain holding period requirements are met) and long-term capital gains (*i.e.*, capital gains on assets held for more than one year) at reduced rates.

Assuming that the distribution, together with certain related transactions, will qualify for tax-free treatment, and subject to the qualifications and limitations set forth herein (including the discussion below relating to the receipt of cash in lieu of fractional shares), for U.S. federal income tax purposes:

- no gain or loss will be recognized by Exelon on the distribution;
- no gain or loss will be recognized by, or be includible in the income of, a U.S. Holder solely as a result of the receipt of our common stock in the distribution;
- the aggregate tax basis of the shares of Exelon common stock and shares of our common stock, including any fractional share deemed received, in the hands of each U.S. Holder immediately after the distribution will be the same as the aggregate tax basis of the shares of Exelon common stock held by such holder immediately before the distribution, allocated between the shares of Exelon common stock and shares of our common stock, including any fractional share deemed received, in proportion to their relative fair market values immediately following the distribution; and
- the holding period with respect to shares of our common stock received by U.S. Holders will include the holding period of their shares of Exelon common stock, provided that such shares of Exelon common stock are held as capital assets immediately following the distribution.

U.S. Holders that have acquired different blocks of Exelon common stock at different times or at different prices are urged to consult their tax advisors regarding the allocation of their aggregate adjusted basis among, and their holding period of, our common stock and Exelon common stock.

If a U.S. Holder receives cash in lieu of a fractional share of our common stock as part of the distribution, the U.S. Holder will be treated as though it first received a distribution of the fractional share in the distribution and then sold it for the amount of cash actually received. Such U.S. Holder will generally recognize capital gain or loss measured by the difference between the cash received for such fractional share and the U.S. Holder's tax basis in that fractional share, as determined above. Such capital gain or loss will be long-term capital gain or loss if the U.S. Holder's holding period for the Exelon common stock exceeds one year on the date of the distribution. The deductibility of capital losses is subject to significant limitations.

Even if the distribution otherwise qualifies for tax-free treatment under Section 355 of the Code, the separation may result in corporate level taxable gain to Exelon under Section 355(e) of the IRC if 50% or more, by vote or value, of the Exelon stock or our stock is treated as directly or indirectly acquired or issued as part of a plan or series of related transactions that includes the distribution (including as a result of transactions occurring before the separation). The process for determining whether an acquisition or issuance triggering these provisions has occurred is complex, inherently factual and subject to interpretation of the facts and circumstances of a particular case, and any such acquisitions may not be within our or Exelon's control. For this purpose, any acquisitions or issuances of Exelon stock within two years before the day of the distribution, and any acquisitions or issuances of our stock or Exelon stock within two years after the day of the distribution generally are presumed to be part of such a plan (subject to certain exceptions and safe harbors), although we or Exelon, as applicable, may be able to rebut that presumption. If an acquisition or issuance of our stock or Exelon stock triggers the application Section 355(e) of the IRC, Exelon could incur significant U.S. federal income tax liabilities attributable to the distribution and certain related transactions, but the distribution would generally be tax-free to each of Exelon shareholders, as described above. Under some circumstances, the tax matters agreement would require us to indemnify Exelon for such tax liability associated with the taxable gain."

U.S. Treasury regulations require certain Exelon shareholders who receive our common stock in the distribution and, immediately prior to the distribution, own (i) at least 5% of the total outstanding stock of Exelon, or (ii) securities of Exelon with an aggregate basis of $1 million or more, to attach to their U.S. federal income tax return for the year in which our stock is received a detailed statement setting forth certain information relating to the tax-free nature of the distribution. U.S. Holders are urged to consult their tax advisors to determine whether they are required to provide the foregoing statement and the contents thereof.

Under the tax matters agreement, we will generally be required to indemnify Exelon for the resulting taxes in the event that the distribution and/or related transactions fail to qualify for their intended tax treatment due to any action by us or any of our subsidiaries. If the distribution were to be taxable to Exelon, the liability for payment of such tax by Exelon or by us under the tax matters agreement could have a material adverse effect on Exelon or us, as the case may be.

WE URGE YOU TO CONSULT WITH YOUR TAX ADVISOR AS TO THE SPECIFIC U.S. FEDERAL, STATE AND LOCAL, AND NON-U.S. TAX CONSEQUENCES OF THE SEPARATION IN LIGHT OF YOUR PARTICULAR CIRCUMSTANCES.

Results of the Separation

After the separation, we will be a publicly-traded company. Immediately following the separation, we expect to have approximately 85,700 record holders of shares of our common stock and approximately 326.5 million shares of our common stock outstanding, based on the number of shareholders and outstanding shares of Exelon common stock on December 31, 2021, and assuming each holder of Exelon common stock will receive one share of our common stock for every three shares of Exelon common stock. The actual number of shares to be distributed will be determined as of the record date.

We anticipate that Exelon equity awards will be exchanged for Company equity awards in connection with the separation and distribution. For information regarding the treatment of equity awards of the Company's directors and executive officers after the distribution, see "Certain Relationships and Related Party Transactions — Agreements with Exelon Related to the Separation — Employee Matters Agreement."

We are in the process of determining the treatment of bonuses in connection with the separation, in respect of (i) the current performance year, (ii) any pre-existing awards that have been earned but that remain unpaid, and (iii) any go-forward bonus programs and/or arrangements. The Company will establish an annual bonus program for our employees for performance periods ending after the spin-off.

Before the separation, we will enter into several agreements with Exelon to effect the separation and provide a framework for our relationship with Exelon after the separation. These agreements will govern the relationship between us and Exelon after completion of the separation and provide for the allocation between us and Exelon of the assets, liabilities, rights and obligations of Exelon. See “Certain Relationships and Related Party Transactions — Agreements with Exelon Related to the Separation.”

Trading Prior to the Distribution Date

See “Trading Market — Trading Prior to the Distribution Date” for information regarding trading in our common stock and Exelon’s common stock prior to the distribution date.

Conditions to the Distribution

We expect that the distribution will be effective as of 12:01 a.m. Eastern time, on February 1, 2022, the distribution date. The distribution is subject to the satisfaction, or waiver by Exelon, of the following conditions:

- the final approval of the distribution by Exelon’s board of directors, which approval may be given or withheld in its absolute and sole discretion;
- our registration statement on Form 10, of which this information statement forms a part, shall have been declared effective by the SEC, with no stop order in effect with respect thereto;
- the mailing by Exelon of this information statement (or notice of internet availability thereof) to record holders of Exelon common stock as of the record date;
- our common stock shall have been approved for listing on NASDAQ, subject to official notice of distribution;
- Exelon shall have received the IRS Ruling and an opinion of its counsel, Sidley Austin LLP, together substantially to the effect that the distribution, together with certain related transactions, will qualify as a tax-free reorganization under Sections 355 and 368(a)(1)(D) of the IRC;
- the following governmental approvals and any required material governmental approvals and other consents necessary to consummate the distribution or any portion thereof shall have been obtained and be in full force and effect:
  - NRC consent and approval to indirectly transfer and to amend the nuclear facility operating licenses,
  - FERC approval to indirectly transfer control of facilities subject to its jurisdiction, through the upstream change in ownership resulting from the separation, and
  - NYPSC approval of the change in the ultimate upstream ownership of three nuclear plants (FitzPatrick, Nine Mile Point and Ginna) located in New York;
- the absence of any events or developments having occurred prior to the distribution that, in the judgment of Exelon’s board of directors, would result in the distribution having a material adverse effect on Exelon or its shareholders;
- our adoption of amended and restated articles of incorporation and amended and restated bylaws and the filing of those documents with the SEC as exhibits to the registration statement on Form 10, of which this information statement forms a part;
- no order, injunction or decree issued by any governmental entity of competent jurisdiction or other legal restraint or prohibition preventing the consummation of all or any portion of the distribution shall be in effect, and no other event shall have occurred or failed to occur that prevents the consummation of all or any portion of the distribution;
- the internal transactions shall have been completed, except for such steps as Exelon in its sole discretion shall have determined may be completed after the distribution date; and

- each of the separation agreement, the tax matters agreement, the employee matters agreement, the transition services agreement and the other ancillary agreements shall have been executed and delivered by each party thereto and be in full force and effect.

The IRS Ruling has been received.

We are not aware of any material federal, foreign or state regulatory requirements that must be complied with or any material approvals that must be obtained in connection with the distribution and separation, other than the aforementioned approvals of the NRC, FERC and NYPSC; compliance with SEC rules and regulations; approval for listing on NASDAQ; and the declaration of effectiveness of the registration statement on Form 10, of which this information statement forms a part, by the SEC. FERC approval was received on August 24, 2021. NRC approval was received on November 16, 2021. On December 16, 2021, the NYPSC approved a settlement agreement among various parties to the proceeding that includes a $15 million contribution to a nuclear plant decommissioning trust, minimum decommissioning trust fund balances at defined points in the decommissioning process, an impact to the Company’s existing asset retirement obligations, and various reporting requirements. A copy of the settlement agreement is filed as an exhibit to the registration statement of which this information statement is a part.

Some of these conditions may not be met and Exelon may waive any of the conditions to the distribution. In addition, until the distribution has occurred, Exelon’s board of directors has the right to not proceed with the distribution, even if all of the conditions are satisfied. In the event Exelon’s board of directors determines to waive a material condition to the distribution, to modify a material term of the distribution or not to proceed with the distribution, Exelon intends to promptly issue a press release or other public announcement and file a Current Report on Form 8-K to report such event.

Reasons for Furnishing this Information Statement

This information statement is being furnished solely to provide information to Exelon shareholders that are entitled to receive shares of Company common stock in the distribution. This information statement is not, and is not to be construed as, an inducement or encouragement to buy, hold or sell any of our securities or any securities of Exelon. We believe that the information in this information statement is accurate as of the date set forth on the cover. Changes may occur after that date and neither Exelon nor we undertake any obligation to update the information.

TRADING MARKET

We intend to list our common stock on NASDAQ under the ticker symbol “CEG.”

Trading Prior to the Distribution Date

Beginning shortly before the record date and continuing up to and including the distribution date, we expect that a limited market, commonly known as a “when-issued” trading market, will develop in our common stock. “When-issued” trading refers to a sale or purchase made conditionally because the security has been authorized but not yet issued. The “when-issued” trading market will be a market for shares of our common stock that will be distributed to Exelon shareholders on the distribution date. If you own shares of Exelon common stock at 5:00 p.m. Eastern time, as of the record date, you will be entitled to shares of our common stock distributed pursuant to the distribution. You may trade this entitlement to shares of our common stock, without trading the shares of Exelon common stock you own, on the “when-issued” market. On the first trading day following the distribution date, “when-issued” trading with respect to our common stock will end and “regular-way” trading will begin. We will announce our when-issued trading symbol when and if it becomes available.

It is also anticipated that, beginning shortly before the record date and continuing up to and including the distribution date, there will be two markets in Exelon common stock: a “regular-way” market and an “ex-distribution” market. Shares of Exelon common stock that trade on the “regular-way” market will trade with an entitlement to shares of Company common stock distributed pursuant to the distribution. Shares that trade on the “ex-distribution” market will trade without an entitlement to shares of our common stock distributed pursuant to the distribution. Therefore, if you own shares of Exelon common stock at the close of business on the record date and sell those shares on the “regular-way” market before the distribution date, you will be selling your right to receive shares of our common stock in connection with the distribution. If you own shares of Exelon common stock at the close of business on the record date and sell those shares on the “ex-distribution” market before the distribution date, you will still receive the shares of our common stock that you would be entitled to receive pursuant to your ownership of the shares of Exelon common stock on the record date. However, if Exelon shareholders own shares of Exelon common stock at 5:00 p.m. Eastern time, as of the record date and sell those shares on the “ex-distribution” market up to and including the distribution date, the selling shareholders will still receive the shares of our common stock that they would otherwise receive pursuant to the distribution.

Market for Our Common Stock

There is currently no public market for our common stock and an active trading market may not develop or may not be sustained.

We cannot predict the prices at which our common stock may trade before the separation on a “when-issued” basis or after the distribution and separation. Those prices will be determined by the marketplace. Prices at which trading in our common stock occurs may fluctuate significantly. Those prices may be influenced by many factors, including anticipated or actual fluctuations in our operating results or those of other companies in our industry, investor perception of the Company and the retail power and gas and power generation business, market fluctuations and general economic conditions. In addition, the stock market in general has experienced extreme price and volume fluctuations that have affected the performance of many stocks and that have often been unrelated or disproportionate to the operating performance of these companies. These are just some factors that may adversely affect the market price of our common stock. See “Risk Factors — Risks Related to Our Common Stock” for further discussion of risks relating to the trading prices of our common stock.

Transferability of Shares of Our Common Stock

On December 31, 2021, Exelon Corporation had approximately 979.5 million shares of its common stock issued and outstanding. Based on this number, we expect that upon completion of the distribution, we will have approximately 326.5 million shares of common stock issued and outstanding. The shares of our common stock that you will receive in the distribution will be freely transferable, unless you are considered an “affiliate” of ours under Rule 144 under the Securities Act. Persons who can be considered our affiliates after the distribution generally include individuals or entities that directly, or indirectly through one or more intermediaries, control, are controlled by, or are under common control with, us, and may include certain of our officers and directors. As of the distribution date, we estimate that our directors and officers will beneficially own in the aggregate less than percent of our shares. In addition, individuals who are affiliates of Exelon on the distribution date may be deemed to be affiliates of ours. Our affiliates may sell shares of our common stock received in the distribution only:

- under a registration statement that the SEC has declared effective under the Securities Act; or
- under an exemption from registration under the Securities Act, such as the exemption afforded by Rule 144.

In general, under Rule 144 as currently in effect, an affiliate will be entitled to sell, within any three-month period commencing 90 days after the date that the registration statement of which this information statement is a part is declared effective, a number of shares of our common stock that does not exceed the greater of:

- 1.0% of our common stock then outstanding; or
- the average weekly trading volume of our common stock on NASDAQ during the four calendar weeks preceding the filing of a notice on Form 144 with respect to the sale.

Sales under Rule 144 are also subject to restrictions relating to manner of sale and the availability of current public information about us.

In the future, we expect to adopt new equity-based compensation plans and issue stock-based awards. We currently expect to file a registration statement under the Securities Act to register shares to be issued under these equity plans. Shares issued pursuant to awards after the effective date of that registration statement, other than shares issued to affiliates, generally will be freely tradable without further registration under the Securities Act.

Except for our common stock distributed in the distribution and employee-based equity awards, we will have no equity securities outstanding immediately after the separation.

DIVIDEND POLICY

We do not have a written policy regarding dividends; however, we expect that we will pay dividends on our common stock commencing following the first full fiscal quarter after the separation. The timing, declaration, amount of and payment of any dividends will be within the sole discretion of our board of directors and will depend on a number of factors, including:

- our historic and projected financial condition, liquidity and results of operations;
- our capital levels and needs;
- tax considerations;
- any acquisitions or potential acquisitions that we may consider;
- statutory and regulatory prohibitions and other limitations;
- the terms of any credit agreements or other borrowing arrangements that restrict our ability to pay cash dividends;
- general economic conditions; and
- other factors deemed relevant by our board of directors.

As a Pennsylvania corporation, we will be subject to certain restrictions on dividends under Pennsylvania corporate law. Generally, a corporation may only pay dividends under the Pennsylvania Business Corporation Law if the total assets of the corporation would be more than the sum of its total liabilities plus the amount that would be needed, if the corporation were to be dissolved at the time as of which the distribution is measured, to satisfy the preferential rights upon dissolution of shareholders whose preferential rights are superior to those receiving the distribution.

Generation expects to enter into a credit agreement concurrent with the distribution that will contain a covenant requiring it to maintain a consolidated leverage ratio calculated as the ratio of its consolidated indebtedness to its consolidated earnings before interest, taxes, depreciation and amortization. Maintaining that ratio may affect Generation’s ability to make distributions to us. See “Description of Certain Indebtedness — Revolving Credit Facility” below for more information.

CAPITALIZATION

The following table presents Generation's unaudited cash and capitalization as of September 30, 2021 on a historical basis, and our unaudited cash and capitalization as of September 30, 2021 on a pro forma basis to give effect to the distribution and separation as if it occurred on September 30, 2021. You can find an explanation of the pro forma adjustments made to the historical unaudited consolidated financial statements under "Unaudited Pro Forma Condensed Consolidated Financial Statements." The capitalization table below should be read together with "Unaudited Pro Forma Condensed Consolidated Financial Statements," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical unaudited consolidated financial statements and accompanying notes included in the "Index to Consolidated Financial Statements" section of this information statement.

We are providing the capitalization table below for informational purposes only. The capitalization table below may not reflect the capitalization or financial condition that would have resulted had we been operated as a stand-alone public company at that date and is not necessarily indicative of our future capitalization or financial condition.

	As of September 30, 2021	
(In millions)	**Historical**	**Pro Forma**
Cash and cash equivalents	$ 1,957	$ 3,386
Restricted cash and cash equivalents	62	62
Total cash, restricted cash, and cash equivalents	2,019	3,448
Indebtedness:		
Short-term:		
Short-term borrowings	1,380	1,380
Long-term debt due within one year	1,216	1,216
Long-term:		
Long-term debt	4,593	4,593
Long-term debt to affiliates	321	—
Total indebtedness	7,510	7,189
Equity:		
Membership interest	10,480	—
Undistributed earnings	1,185	—
Common stock (no par value, 1,000 shares authorized and 326 shares outstanding, pro forma)(1)	—	13,560
Accumulated other comprehensive loss, net	(31)	(2,067)
Noncontrolling interests	401	401
Total equity	12,035	11,894
Total capitalization	19,545	19,083

(1) We have estimated the number of outstanding shares of our common stock based on the number of shares of Exelon common stock outstanding on September 30, 2021 and applying the distribution ratio of one share of our common stock for every three shares of Exelon common stock.

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On February 21, 2021, Exelon's board of directors authorized management to pursue a plan to separate its competitive generation and customer-facing energy businesses into a stand-alone publicly traded company. The separation will occur through a distribution to Exelon's shareholders of all of the shares of common stock of the Company, which will own Generation, including its competitive generation, customer-facing power and gas supply, and related businesses. Following the distribution, Exelon shareholders will own 100% of the shares of our common stock.

The unaudited pro forma condensed consolidated financial statements as of and for the nine months ended September 30, 2021 have been derived from the historical unaudited consolidated financial statements of Generation, included elsewhere in this information statement. The unaudited pro forma condensed consolidated financial statements for the year ended December 31, 2020 have been derived from the historical audited consolidated financial statements of Generation, included elsewhere in this information statement. The unaudited pro forma condensed consolidated statement of operations for the nine months ended September 30, 2021 and the year ended December 31, 2020 gives effect to the separation and related transactions, including the purchase of the noncontrolling interest in CENG, as if they had occurred on January 1, 2020, the beginning of the most recent fiscal year for which audited financial statements are available. The unaudited pro forma condensed consolidated balance sheet as of September 30, 2021 gives effect to the separation and related transactions, as if they had occurred on September 30, 2021.

The unaudited pro forma condensed consolidated financial statements were prepared in accordance with Article 11 of Regulation S-X. The unaudited pro forma condensed consolidated financial statements were prepared for illustrative and informational purposes only and are not intended to represent what our results of operations or financial position would have been had the separation and the purchase of the noncontrolling interest in CENG occurred on the dates indicated. The unaudited pro forma condensed consolidated financial statements also should not be considered indicative of our future results of operations or financial position as an independent, publicly traded company. The actual financial position and results of operations may differ significantly from the pro forma amounts reflected herein due to a variety of factors. See "Cautionary Note Regarding Forward-Looking Statements" included in this information statement. The unaudited pro forma condensed consolidated financial information does not reflect the realization of any expected cost savings or other synergies as a result of the separation and related transactions, including the purchase of the noncontrolling interest in CENG.

On November 20, 2019, Generation received notice that, pursuant to an April 1, 2014 Put Option Agreement, EDF intended to exercise its put option to sell to Generation its 49.99% equity interest in CENG. Following the required sixty-day notice period, the put option was automatically exercised on January 19, 2020. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation, through a wholly owned subsidiary, purchased EDF's equity interest in CENG for a net purchase price of $885 million, which includes, among other things, a credit for EDF's share of the balance of a preferred distribution payable by CENG to Generation. The difference between the net purchase price and EDF's noncontrolling interest as of the closing date was recorded to Membership interest on our Consolidated Balance Sheet.

On December 16, 2021, the NYPSC issued an order approving a joint proposal agreement with the Staff of the New York State Department of Public Service, the New York State Office of the Attorney General and the Alliance for a Green Economy regarding approval for Exelon's plan to separate its utilities business and Generation, including Generation's three nuclear power plants in New York. The New York joint proposal agreement will impact the Company's existing asset retirement obligations. As a result, on a pro forma basis, the Company revised its asset retirement obligation upward. The New York joint proposal agreement will become effective upon the closing of the separation.

The following unaudited pro forma condensed consolidated statement of operations and unaudited pro forma condensed consolidated balance sheet give pro forma effect to the following:

Separation transaction accounting adjustments

- the issuance of shares of the Company's common stock based on the distribution ratio of one share of our common stock for every three shares of Exelon common stock outstanding on the record date.

- the impact of the separation agreement, employee matters agreement, tax matters agreement, New York joint proposal agreement, and the provisions therein.

CENG put transaction adjustments

- reflects the elimination of CENG's non-controlling interest and interest expense related to the issuance of approximately $880 million under a 364-day term loan credit agreement to fund the purchase of 49.99% noncontrolling interest in CENG from EDF in accordance with the Put Option Agreement.
- the adjustment of the provision (benefit) for income taxes related to the taxation of income previously attributable to noncontrolling interest holders.

The following unaudited pro forma condensed consolidated financial statements should be read in conjunction with:

- Management's Discussion and Analysis of Financial Condition and Results of Operations, which is included elsewhere within this information statement.
- the historical unaudited consolidated financial statements and accompanying notes of Generation as of and for the nine months ended September 30, 2021, which are included elsewhere within this information statement.
- the historical audited consolidated financial statements and accompanying notes of Generation as of and for the year ended December 31, 2020, which are included elsewhere within this information statement.
- the accompanying notes to the pro forma financial information.

Generation has been an individual registrant since the registration of their public debt securities under the Securities Act in 2002. As an individual registrant, Generation has historically filed consolidated financial statements to reflect their financial position and operating results as a stand-alone, wholly owned subsidiary of Exelon. To operate as an independent, publicly traded company, we expect our recurring costs to replace certain services to approximate those costs historically allocated to Generation from Exelon. The significant assumptions involved in determining our estimates of the recurring costs of being an independent, publicly traded company include, but are not limited to, costs to perform financial reporting, tax, corporate governance, treasury, legal, internal audit and investor relations activities; compensation expense, including equity-based awards, and benefits; incremental third-party costs with respect to insurance, audit services, tax services, employee benefits and legal services. The operating and maintenance expenses reported in our historical consolidated statements of operations reflect all expenses incurred as a stand-alone company and include allocations of certain Exelon costs. These costs include allocation of Exelon corporate costs that benefit us, including corporate governance, executive management, finance, legal, information technology, human resources, and other general and administrative costs. We estimate the costs to operate as an independent, publicly traded company approximate the amount of allocated costs that have been presented in our historical consolidated statements of operations and as such an autonomous entity pro forma adjustment has not been made to the accompanying Unaudited Pro Forma Condensed Consolidated Statement of Operations. Certain factors could impact these stand-alone public company costs, including the finalization of our staffing and infrastructure needs.

CONSTELLATION ENERGY CORPORATION

Unaudited Pro Forma Condensed Consolidated Statement of Operations for the Nine Months Ended September 30, 2021

	For the Nine Months Ended September 30, 2021			
		Pro Forma Adjustments (Note 2)		
(In millions, except per share data)	Historical	Separation Transaction Accounting Adjustments	CENG Put Transaction Accounting Adjustments	Pro Forma
Operating revenues				
Operating revenues	$13,245	$ 872(e)		$14,117
Operating revenues from affiliates	872	(872)(e)		—
Total operating revenues	14,117	—	—	14,117
Operating expenses				
Purchased power and fuel	8,103			8,103
Operating and maintenance	2,955	458(e)		3,386
		(38)(d)		
		11(i)		
Operating and maintenance from affiliates	458	(458)(e)		—
Depreciation and amortization	2,735	41(i)		2,776
Taxes other than income taxes	354			354
Total operating expenses	14,605	14	—	14,619
Gain on sales of assets and businesses	144			144
Operating income	(344)	(14)	—	(358)
Other income and (deductions)				
Interest expense, net	(214)			(214)
Interest expense to affiliates	(11)	11(b)		—
Other, net	561	(38)(d)		523
Total other income and (deductions)	336	(27)	—	309
Income before income taxes	(8)	(41)	—	(49)
Income taxes	108	(10)(l)	(38)(k)	60
Equity in losses of unconsolidated affiliates	(6)			(6)
Net income	(122)	(31)	38	(115)
Net (loss) income attributable to noncontrolling interests	125		153(j)	278
Net income attributable to membership interest or common shareholders	(247)	(31)	(115)	(393)
Average shares of common stock outstanding (Note 3):				
Basic	N/A			326
Diluted	N/A			326
Earnings per average common share (Note 3):				
Basic	N/A			$ (1.20)
Diluted	N/A			$ (1.20)

CONSTELLATION ENERGY CORPORATION

Unaudited Pro Forma Condensed Consolidated Statement of Operations for the Year Ended December 31, 2020

	For the Year Ended December 31, 2020			
		Pro Forma Adjustments (Note 2)		
(In millions, except per share data)	Historical	Separation Transaction Accounting Adjustments	CENG Put Transaction Accounting Adjustments	Pro Forma
Operating revenues				
Operating revenues	$16,392	$ 1,211(e)		$17,603
Operating revenues from affiliates	1,211	(1,211)(e)		—
Total operating revenues	17,603	—	—	17,603
Operating expenses				
Purchased power and fuel	9,592	(7)(e)		9,585
Purchased power and fuel from affiliates	(7)	7(e)		—
Operating and maintenance	4,613	555(e)		5,128
		(55)(d)		
		15(i)		
Operating and maintenance from affiliates	555	(555)(e)		—
Depreciation and amortization	2,123	54(i)		2,177
Taxes other than income taxes	482			482
Total operating expenses	17,358	14	—	17,372
Gain on sales of assets and businesses	11			11
Operating income	256	(14)	—	242
Other income and (deductions)				
Interest expense, net	(328)		(12)(j)	(340)
Interest expense to affiliates	(29)	29(b)		—
Other, net	937	(55)(d)		882
Total other income and (deductions)	580	(26)	(12)	542
Income before income taxes	836	(40)	(12)	784
Income taxes	249	(10)(l)	(3)(k)	236
Equity in losses of unconsolidated affiliates	(8)			(8)
Net income	579	(30)	(9)	540
Net loss attributable to noncontrolling interests	(10)		3(j)	(7)
Net income attributable to membership interest or common shareholders	589	(30)	(12)	547
Average shares of common stock outstanding (Note 3):				
Basic	N/A			326
Diluted	N/A			326
Earnings per average common share (Note 3):				
Basic	N/A			$ 1.68
Diluted	N/A			$ 1.68

CONSTELLATION ENERGY CORPORATION

Unaudited Pro Forma Condensed Consolidated Balance Sheet as of September 30, 2021

	As of September 30, 2021		
		Pro Forma Adjustments (Note 2)	
(In millions)	**Historical**	**Separation Transaction Accounting Adjustments**	**Pro Forma**
ASSETS			
Current assets			
Cash and cash equivalents	$ 1,957	(321)(b)	$ 3,386
		1,750(g)	
Restricted cash and cash equivalents	62		62
Accounts receivable			
Customer accounts receivable	1,412	184(e)	1,596
Customer allowance for credit losses	(84)		(84)
Customer accounts receivable, net	1,328	184	1,512
Other accounts receivable	465		465
Other allowance for credit losses	(4)		(4)
Other accounts receivable, net	461	—	461
Mark-to-market derivative assets	1,505		1,505
Receivables from affiliates	184	(184)(e)	—
Unamortized energy contract assets	36		36
Inventories, net			
Fossil fuel and emission allowances	240		240
Materials and supplies	998		998
Renewable energy credits	486		486
Assets held for sale	11		11
Other	1,319	83(f)	1,402
Total current assets	8,587	1,512	10,099
Property, plant and equipment (net of accumulated depreciation and amortization of $15,966)	19,574	42(h)	20,181
		565(i)	
Deferred debits and other assets			
Nuclear decommissioning trust funds	15,404		15,404
Investments	165		165
Goodwill	47		47
Mark-to-market derivative assets	664		664
Prepaid pension asset	1.702	(1,702)(c)	—
Unamortized energy contract assets	265		265
Deferred income taxes	13		13
Other	1,589	510(f)	2,099
Total deferred debits and other assets	19,849	(1,192)	18,657
Total assets	$48,010	927	$48,937

CONSTELLATION ENERGY CORPORATION

Unaudited Pro Forma Condensed Consolidated Balance Sheet as of September 30, 2021

(In millions)	Historical	Pro Forma Adjustments (Note 2) Separation Transaction Accounting Adjustments	Pro Forma
	As of September 30, 2021		
LIABILITIES AND EQUITY			
Current liabilities			
Short-term borrowings	$ 1,380		$ 1,380
Long-term debt due within one year	1,216		1,216
Accounts payable	1,612	154(e)	1,766
Accrued expenses	691		691
Payables to affiliates	154	(154)(e)	—
Mark-to-market derivative liabilities	1,709		1,709
Unamortized energy contract liabilities	2		2
Renewable energy credit obligation	682		682
Liabilities held for sale	3		3
Other	347		347
Total current liabilities	7,796	—	7,796
Long-term debt	4,593		4,593
Long-term debt to affiliates	321	(321)(b)	—
Deferred credits and other liabilities			
Deferred income taxes and unamortized investment tax credits	3,685	(645)(c)	3,656
		615(f)	
Asset retirement obligations	12,635	565(i)	13,200
Pension obligations	—	810(c)	810
Non-pension postretirement benefit obligations	857	66(c)	923
Spent nuclear fuel obligation	1,209		1,209
Contractual obligation for regulatory agreement units	—	3,143(e)	3,143
Payables to affiliates	3,143	(3,143)(e)	—
Mark-to-market derivative liabilities	511		511
Unamortized energy contract liabilities	1		1
Other	1,224	(22)(f)	1,202
Total deferred credits and other liabilities	23,265	1,389	24,654
Total liabilities[a]	35,975	1,068	37,043
Commitments and contingencies			
Equity			
Member's equity			
Membership interest	10,480	(12,375)(a)	—
		103(c)	
		1,750(g)	
		42(h)	
Undistributed earnings	1,185	(1,185)(a)	—
Accumulated other comprehensive loss, net	(31)	2,067(a)	—
		(2,036)(c)	
Shareholders' equity			
Common stock	—	13,560(a)	13,560

CONSTELLATION ENERGY CORPORATION

Unaudited Pro Forma Condensed Consolidated Balance Sheet as of September 30, 2021

(In millions)	As of September 30, 2021 Historical	Pro Forma Adjustments (Note 2) Separation Transaction Accounting Adjustments	Pro Forma
Accumulated other comprehensive loss, net	—	(2,067)(a)	(2,067)
Total member’s or shareholders’ equity	11,634	(142)	11,493
Noncontrolling interests	401		401
Total equity	12,035	(142)	11,894
Total liabilities and equity	$48,010	927	$48,937

Notes to Unaudited Pro Forma Condensed Consolidated Financial Statements

1. Basis of Presentation

The historical financial information as of and for the nine months ended September 30, 2021 is derived from and should be read in conjunction with the historical unaudited consolidated financial statements of Generation appearing elsewhere in this information statement and the assumptions outlined in Note 2 below. The historical financial information for the year ended December 31, 2020 is derived from and should be read in conjunction with the historical audited consolidated financial statements of Generation appearing elsewhere in this information statement and the assumptions outlined in Note 2 below.

2. Pro Forma Adjustments and Assumptions

Separation transaction accounting adjustments

(a) Reflects the issuance of shares of Company common stock based on the distribution ratio of one share of Company common stock for every three shares of Exelon common stock outstanding on the record date and reflects the elimination of historical membership interest and undistributed earnings.

(b) Reflects the repayment of $321 million of intercompany debt between Generation and Exelon and the elimination of the related interest expense.

(c) Reflects the estimated impact to prepaid pension asset, deferred income taxes and unamortized investment tax credits, pension obligations, non-pension postretirement benefit obligations, membership interest, and accumulated other comprehensive income resulting from the legal separation of the pension and OPEB plans, historically sponsored by Exelon and accounted for as multi-employer benefit plans, related to current and former Exelon employees transferred to the Company in accordance with the employee matters agreement.

(d) Reflects the estimated impact to operating and maintenance and other, net for the presentation reclass of non-service cost components resulting from the legal separation of the pension and OPEB plans, historically sponsored by Exelon and accounted for as multi-employer benefit plans, related to current and former Exelon employees transferred to the Company in accordance with the employee matters agreement.

(e) Reflects the reclassification of sales, purchases and other intercompany transactions between the Company and Exelon’s utility subsidiaries, from related party transactions to third-party transactions. Other intercompany transactions include long-term payables to ComEd and PECO related to nuclear decommissioning of Regulatory Agreement Units. See Note 10 — Asset Retirement Obligations of the Notes to Audited Consolidated Financial Statements for additional information.

(f) Reflects the elimination of the deferred tax asset related to tax credit carryforwards and uncertain tax positions that will be retained by Exelon and the recognition of the related receivable from Exelon and indemnification payable to Exelon in accordance with the tax matters agreement.

(g) Reflects the expected cash payment from Exelon to the Company of $1.75 billion in accordance with the separation agreement. The Company expects to enter into one or more transactions with Exelon prior to the consummation of the spin-off such that the expected cash payment will be made as of the distribution date.

(h) Reflects the net book value for the transfer of certain assets from Exelon to the Company under common control prior to the separation in accordance with the separation agreement. There may be additional assets, liabilities or related expenses transferred to the Company in connection with the separation for which the terms of the transfer has not been finalized in the separation agreement.

(i) Reflects the estimated impact to the Company’s existing asset retirement obligations, property, plant and equipment, operating and maintenance, and depreciation and amortization for certain New York nuclear sites associated with the execution of the New York joint proposal agreement. The estimated impact is subject to change based on certain assumptions, including current discount rates upon separation and other inputs that could materially impact the results.

CENG put transaction accounting adjustments

(j) Reflects the elimination of CENG’s non-controlling interest and interest expense related to the issuance of approximately $880 million under a 364-day term loan credit agreement to fund the purchase of 49.99% noncontrolling interest in CENG from EDF in accordance with the Put Option Agreement. The term loan bears interest at a variable rate equal to LIBOR plus a risk premium. The interest rates assumed for purposes of preparing this pro forma financial information comprise of the LIBOR rate of 0.38% as of November 30, 2021 plus the risk premium specified in the credit agreement. A 1/8% change to the annual interest rate would change interest expense by approximately $1.1 million on an annual basis.

(k) Reflects the adjustment of the provision (benefit) for income taxes related to the taxation of income previously attributable to noncontrolling interest holders and for the adjustments made to income (loss) before income taxes at an estimated statutory rate of approximately 25%.

Other transaction accounting and autonomous entity adjustments

(l) Reflects the adjustment of the provision (benefit) for income taxes for the adjustments made to income (loss) before income taxes at an estimated statutory rate of approximately 25%.

3. Pro Forma Earnings Per Share

The pro forma weighted-average basic and diluted shares outstanding and pro forma basic and diluted earnings per share for the nine months ended September 30, 2021 and year ended December 30, 2020 reflect the estimated number of outstanding shares of our common stock upon the consummation of the separation. We have estimated the number of outstanding shares of our common stock based on the number of shares of Exelon common stock outstanding on September 30, 2021 and applying the distribution ratio of one share of our common stock for every three shares of Exelon common stock. For more information on the distribution ratio, see Note 2(a) above.

OVERVIEW OF THE U.S. POWER MARKETS

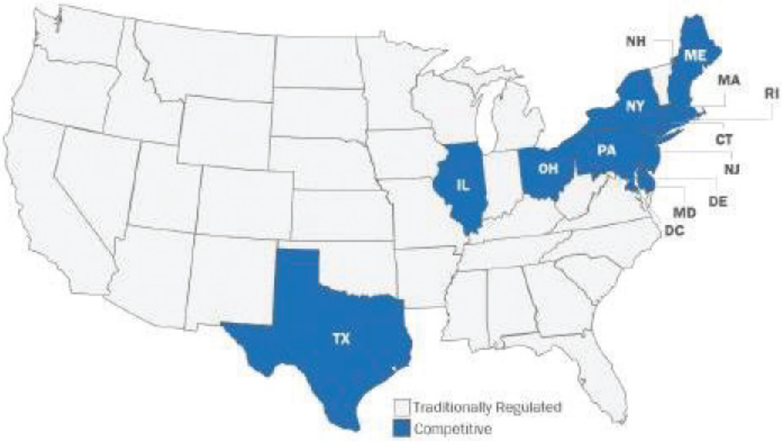
Prior to the 1990s, most electricity customers in the U.S. were served by regulated, vertically-integrated utilities. During the late 1990s, organized regional competitive wholesale markets began to form and many states in the U.S. also pursued competitive retail structures allowing non-utility generators to sell electricity to utilities and/or retail service providers to sell to end-use customers. Deregulation of the U.S. electric industry has progressed differently across the U.S., with the states in the Northeast, Mid-Atlantic, and Texas generally being the most deregulated and the states in the Southeast and much of the Midwest and West generally being the most regulated. A recent key trend in the U.S. power markets is the growing shift toward clean energy. Nuclear power facilities are particularly well-positioned to respond to and benefit from this trend, as nuclear power provides reliable, carbon-free baseload power to meet the evolving needs of power markets and customers across the U.S.

Competitive Retail Energy Markets

Retail competition in states across the U.S. ranges from full competition of generation supplier for all retail customers (commercial, industrial and residential) to partial retail competition available up to a capped amount for industrial customers only.

The District of Columbia and thirteen states (Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island and Texas) have implemented full retail competition for nearly all customers of investor owned utilities. These competitive jurisdictions represent nearly one-third of all electricity consumption in the continental U.S.

14 Customer Choice Jurisdictions[(a)]



(a) Source: Retail Energy Supply Association, June 1, 2020

In these states allowing full retail competition, regulated utilities continue to provide transmission and distribution service at regulated rates. Generation service, however, is no longer rate regulated. Instead, the rates paid by customers are those offered by competitive retail electricity suppliers or, for customers who do not receive service from competitive suppliers, utility provided POLR service that is reflective of wholesale market prices.

There are also several additional states in the U.S. that offer limited electric customer choice and may be considered "hybrid" models. For example, states including California, Michigan, Arizona, Oregon, Nevada, Virginia, Washington and Montana allow limited portions of total load to be served competitively at retail.

Competitive Wholesale Markets

Distinct from retail markets, which involve the sales of electricity directly to consumers, wholesale markets involve the sales of electricity among electric utilities and electricity marketers before it is eventually sold to end-use consumers. These jurisdictions include many of the most populous states.

Some regions of the country have evolved further in terms of forming ISOs or RTOs, which are FERC-regulated entities that coordinate, control, and monitor the operation of the electrical power system. Examples include PJM, ISO-NE and NYISO. Approximately two-thirds of the nation’s wholesale electricity sales occur in competitive markets managed by the ISOs or RTOs. These regions have independent oversight of the wholesale markets, and are regulated by FERC, which provides oversight of the operators that encompass multiple states (all but ERCOT). ISOs and RTOs generally afford more formalized and structured wholesale electricity markets than non-ISO or non-RTO regions and have implemented mechanisms to facilitate market monitoring, reliability and efficiency. ISO/RTO-guided initiatives, such as locational marginal pricing and capacity markets, are designed to send the appropriate price signal for new investment in capacity when new capacity is needed to maintain system reliability. ERCOT is unique in that its locational marginal pricing is based solely on system energy and congestion, with no accounting for marginal losses occurring on the system. While not yet formalized into an ISO or RTO, many of the previously fragmented dispatch and control areas in the Western part of the US are starting to combine, as they recognize both the operational benefits, as well as the ability to save money for customers through sharing and co-optimization of generation resources and reserves.

PJM. 65% of our generation fleet, measured by net generating capacity, operates within the PJM market. By MW, our generation fleet in PJM consists of approximately 78% nuclear, 9% renewables, 8% gas and 5% oil. PJM is the largest power market in the US and is comprised of all or parts of 13 Mid-Atlantic and Midwestern states and the District of Columbia. PJM is one of the most advanced power markets in the U.S., with nodal day-ahead and real-time energy markets, ancillary service products, and a forward capacity market (the Reliability Pricing Model or RPM) that clears capacity three years in advance of the capacity commitment period.

PJM forecasted 150.2 GW of peak load in the 2022/2023 delivery year with a minimum reserve margin of 14.50%. PJM relies heavily on natural gas-fired and coal-fired generation. PJM’s installed capacity mix in 2020 includes 28% coal, 27% natural gas, 18% nuclear, 15% gas / other secondary capacity, 5% water, 5% oil and 2% other.

Natural gas pricing is one of the primary drivers of energy prices throughout PJM. The discovery and production of vast amounts of shale gas in the U.S., particularly from the Marcellus and Utica shales within the bounds of PJM, combined with development of significant amounts of new efficient gas-fired generation has resulted in a decline in wholesale power prices in PJM.

State policies also impact the investment decisions of resources in the PJM market, including state RPS programs, ZEC and/or CMC programs in Illinois and New Jersey, and the Regional Greenhouse Gas Initiative (RGGI). RGGI is a mandatory greenhouse gas cap and trade program that imposes costs via the purchase of allowances for in-state fossil fuel generators. Eleven states in the Northeast and Mid-Atlantic are members of the RGGI program and Pennsylvania is in the process of joining the program.

Source: PJM Capacity By Fuel Type 2020, PJM 2022/2023 RPM Base Residual Auction Planning Period Parameters.

ERCOT. 12% of our generation fleet, measured by net generating capacity, operates within the ERCOT market. By MW, our generation fleet in ERCOT consists of approximately 97% gas and 3% renewables. ERCOT is the system operator for most of Texas and is not under FERC jurisdiction due to the market being solely located within the state of Texas and not being synchronously interconnected to another part of the U.S. The ERCOT market is projected to have 86.8 GW of capacity available in summer 2021 to meet a peak demand of 75.2 GW, resulting in a reserve margin of 15.5%. ERCOT’s fuel mix for 2021 is projected to consist of 32% gas (combined-cycle), 28% wind, 19% coal, 12% nuclear, 6% gas, and 3% solar, with less than 0.2% from biomass, hydro and other.

As an energy-only market, ERCOT's market design is different from other competitive electricity markets in the U.S. Other markets, including PJM, maintain a minimum reserve margin through regulated planning, resource adequacy requirements and/or capacity markets. In contrast, ERCOT's resource adequacy is predominately dependent on free market processes and energy market price signals. All electricity prices are subject to a system-wide offer cap, which is $9,000/MWh, as of July 2021.

Source: ERCOT 2021 Fuel Mix Report, ERCOT December 2020 Capacity Demand and Reserves Report.

NYISO. 6% of our generation fleet, measured by net generating capacity, operates within the NYISO Market. By MW, our generation fleet in NYISO consists of almost 100% nuclear. Established in 1999 as one of the first ISOs, NYISO features liquid day-ahead and real-time energy and ancillary service markets. NYISO also has a spot capacity market, called the ICAP market, which clears capacity up to 6 months in advance of the delivery period. As a result, power generation within NYISO can earn revenues from liquid ancillary, energy and capacity markets. There are four distinct supply and demand zones in the NYISO market: ROS (generally encompassing upstate New York), Zone G-J (known as the "G-J Locality" and located in the Lower Hudson Valley), Zone J (New York City), and Zone K (Long Island). The overall market is known as NYCA.

NYISO is projected to have 41.1 GW of capacity available to meet 32.3 GW of projected peak demand in 2021, resulting in a reserve margin of 27.0%. NYISO is heavily reliant on natural gas and oil-fired generators with hydro and nuclear resources rounding out most of the remainder. NYISO's generation supply stack is characterized by numerous aging plants. Over 15 GW of generating capacity, representing over 38% of NYISO's total generation capacity, is over 50 years old.

Source: NYISO 2021 Gold Book, April 2021.

Other power markets. The remaining 17% of our generation fleet operates in other markets including CAISO, ISO-NE, MISO and SPP in the U.S. and AESO in Canada. Our generation in these markets, by MW, consists of approximately 20% nuclear, 46% gas, 13% oil and 20% renewables.

The CAISO market serves customers primarily in California. CAISO features day-ahead and real-time energy markets and ancillary service markets. While CAISO does not operate a formal capacity market, it does have a mandatory resource adequacy requirement supported through bilateral contracts.

The ISO-NE market covers the six states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. It offers day-ahead and real time energy markets, ancillary service products, and a forward capacity market.

MISO is an RTO that covers all or parts of 15 states: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin; as well as the Canadian province of Manitoba. MISO operates day-ahead and real time energy markets and ancillary service markets. Capacity requirements are addressed through bilateral transactions or a voluntary annual auction that MISO administers.

SPP has members in 14 states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. It also provides contract reliability coordination services in Arizona, Colorado and Utah. SPP operates day-ahead and real-time energy markets and transmission service markets.

AESO provides the function of Independent System Operator in Alberta, Canada, where we own one generation asset. It is currently an energy-only model and does not operate a capacity market. AESO also operates a separate ancillary services market where resources provide specific services that help maintain grid reliability.

PJM Base Residual Auction. The PJM Base Residual Auction ("BRA") is PJM's annual capacity auction to procure power supply resources in advance of a specific delivery year to meet electricity needs for PJM. In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while recognizing certain reliability-based constraints on the location and type of capacity that can be committed.

Auctions are typically held three years prior to the delivery year. The 2022/2023 Delivery Auction was originally scheduled to be held in May 2019 but was postponed as FERC considered approval of new capacity market rules. In November 2020, PJM announced a revised auction schedule for the next six auctions. In May 2021, PJM conducted its first annual capacity auction since May 2018 and posted the results of the 2022/2023 Delivery Year auction on June 2, 2021. PJM’s next auction, for the 2023/2024 Delivery Year, is scheduled to take place in December 2021, although PJM has requested that auction be delayed until January 2022 to allow time for PJM to implement additional changes to its capacity market rules.

MOPR Proceedings. PJM and NYISO capacity markets include a MOPR. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a government-provided financial support program, resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the MOPR in PJM applied only to certain new gas-fired resources. Currently, the MOPR in NYISO applies only to certain resources in downstate New York.

On December 19, 2019, FERC required PJM to broadly apply the MOPR to all new and existing resources including nuclear, renewables, demand response, energy efficiency, storage and all resources owned by vertically-integrated utilities. This greatly expanded the breadth and scope of PJM’s MOPR, which became effective as of PJM’s capacity auction for the 2022/23 Delivery Year. While FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources. As a result, the MOPR applied in the 2022/23 capacity auction to our owned or jointly owned nuclear plants in those states receiving a benefit under the Illinois ZES and the New Jersey ZEC program. The MOPR prevented Quad Cities from clearing in the capacity auction.

At the direction of the PJM Board of Managers, PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. PJM filed related tariff revisions at FERC on July 30, 2021. On September 29, 2021, PJM’s proposed MOPR reforms become effective by operation of law. Under the new tariff provisions, the MOPR will no longer apply to any of our owned or jointly owned nuclear plants.

Key Drivers

The U.S. energy sector is experiencing unprecedented changes that we believe will increase the demand for reliable, clean power generation and benefit our business. We believe our generation fleet, including our nuclear assets, is well-positioned to deliver reliable, clean power and benefit from the higher prices that higher demand is expected to drive.

Key drivers of increased demand for clean energy include:

- governmental and corporate policies designed to accelerate the de-carbonization of the economy, including continued momentum for incentives for and investment in wind and solar, along with emerging carbon-free technologies like storage and hydrogen;
- policy support for nuclear energy sources that also enable energy security, reliability and diversification;
- the rapid electrification of the U.S. economy; and
- evolving customer preferences favoring clean energy, choice and digitization, to which we believe our customer-facing business is well-positioned to respond.

We believe existing nuclear generation, which is currently the largest source of zero emissions electricity in the U.S. accounting for approximately 20% of total 2020 utility-scale electricity generation in the U.S. and complementing other zero-carbon power sources, is essential to achieving existing and future policy objectives for the reduction of GHG emissions. A 2018 study by the Massachusetts Institute of Technology, “The Future of Nuclear Energy in a Carbon-Constrained World,” found that the costs of achieving transformational de-carbonization targets would increase significantly without the contribution of nuclear power.

Policy Support for De-Carbonization and Emerging Carbon-Free Technologies. Driven by societal concerns about climate change, governments, corporations, and investors are increasingly advocating for the reduction of GHG emissions across all sectors of the economy, with reduction of GHG emissions by the energy sector being a key focus. Governments at the international, national and state levels have established or are currently contemplating increasingly stringent policies that require the reduction of GHG emissions over time. Corporations have also adopted targets to reduce the carbon emissions in their business operations, spurred in part by demand from investors and customers for sustainable, environment-friendly business practices. Emerging technologies like storage and hydrogen are also helping to advance de-carbonization.

As decarbonization accelerates, we expect our generation fleet will play a critical role in meeting baseload power needs. Nuclear energy is key to achieving decarbonization objectives, given its existing penetration of the U.S. market today and its greater reliability than renewable energy sources. We believe our business is well-positioned to benefit from growing policy support for de-carbonization, which will drive higher demand and higher prices for the reliable, zero-carbon power our nuclear assets generate.

International Climate Change Agreements. At the international level, the U.S. is a party to the United Nations Framework Convention on Climate Change (UNFCCC). The parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015, and it became effective on November 4, 2016. Under the Paris Agreement, the parties agreed to try to limit the global average temperature increase to 2°C (3.6°F) above pre-industrial levels. In doing so, parties developed their own national reduction commitments. The Biden administration has announced a new target of 50-52 percent reduction in U.S. Greenhouse Gas Pollution from 2005 Levels by 2030. In order to achieve this target and maintain high standards of reliability, the U.S. will need a reliable baseload of zero-carbon generating electricity sources, which our nuclear fleet helps provide.

Federal Climate Change Legislation and Regulation. Combating climate change is one of the top legislative agenda items of the Biden administration. U.S. President Biden's stated climate change policy targets 100% clean energy economy with net zero GHG emissions no later than 2050. Within the U.S. power sector specifically, the Biden agenda calls for zero GHG emissions from electricity generation by 2035. Since entering office in January 2021, U.S. President Biden has signed a number of executive orders targeting climate change that include removing certain subsidies for the fossil fuel industry. On March 31, 2021, President Biden proposed the American Jobs Plan, a $2 trillion infrastructure plan that includes measures to combat climate change, such as spending on electric vehicle charging and the creation of a Clean Electricity Standard requiring 100 percent of electricity in the United States to be generated by carbon-free sources by 2035. On Earth Day 2021, President Biden emphasized his commitment to mitigating climate change and pledged to cut U.S. greenhouse gas pollution in half by 2030. While it remains uncertain if the Build Back Better plan or other U.S. federal legislation to reduce GHG emissions will be enacted in the near-term, such legislation would increase the need for reliable carbon-free power generation, which would benefit us as the nation's largest carbon-free power producer.

Given the Administration's aggressive goals for reducing emissions within the electric power sector, policymakers have recognized the urgent need to prevent the retirement of nuclear power plants prior to the end of their licensed lives. Nuclear energy provides 20 percent of the nation's electricity and over 50 percent of the nation's carbon free power. A dozen nuclear reactors have closed in recent years, primarily as a result of economic challenges in merchant power markets. Representative Bill Pascrell (D-NJ) and Senator Ben Cardin (D-MD) have introduced legislation to provide a $15/megawatt hour production tax credit for merchant nuclear power plants. The amount of the PTC is decreased for plants with revenues exceeding $25/megawatt hour. The U.S. Treasury Department proposed an allocated production tax credit for nuclear plants as part of their annual "Green Book" compilation of tax priorities for the Administration. The outlook for this legislation is directly tied to action on legislation extending other clean energy tax credits and remains uncertain.

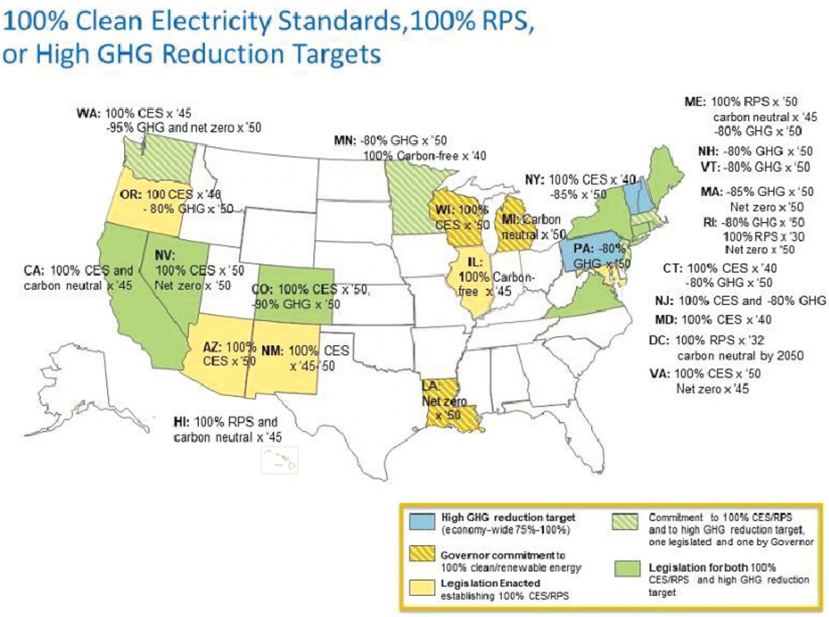
Regional and State Climate Change Legislation and Regulation. A number of states in which we operate have state and regional programs to reduce GHG emissions, including from the power sector. Eleven northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia) currently participate in the RGGI, which is in the process of strengthening its requirements. The program requires most fossil fuel-fired power plants in the region to hold allowances, purchased at auction, for each ton of CO2 emissions. Non-emitting resources do not have to purchase or hold these allowances.

In October 2019, Governor Wolf of Pennsylvania issued an Executive Order that directed the Pennsylvania Department of Environmental Protection to begin a rulemaking process that will allow Pennsylvania to join RGGI, with the goal of reducing carbon emissions from the electricity sector.

Many states in which we operate also have state-specific programs to address GHGs, including from power plants. Most notable of these, besides RGGI, are renewable and other portfolio standards. In 2019, New York enacted the Climate Leadership and Community Protection Act, which commits the state to achieving net zero emissions by 2050 with interim emission reduction and renewable energy requirements in 2030 and 2040. On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy.

Renewable and Clean Energy Standards. According to the National Conference of State Legislatures (NCSL), thirty states and the District of Columbia have adopted an RPS, while seven more states have set renewable energy goals. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. Twenty-four states and the District of Columbia have 100% clean electricity targets, deep GHG reduction targets, or both, encompassing 53% of U.S. residential electricity customers. Utilities comply with these various requirements through purchasing qualifying renewables, implementing efficiency programs, acquiring sufficient credits (e.g., RECs), paying an alternative compliance payment, and/or a combination of these compliance alternatives. New York, Illinois and New Jersey adopted standards targeted at preserving the zero-carbon attributes of certain nuclear-powered generating facilities. We own multiple facilities participating in these programs within these states. Other states in which our generation facilities operate are considering similar programs. We believe our nuclear assets can play a key role in helping states achieve these goals by providing fuel-secure power that maintains grid reliability and complements variable renewable sources like wind and solar.

100% Clean Electricity Standards, 100% RPS, or High GHG Reduction Targets by State[(a)]



(a) Source: Clean Air Task Force, state public disclosures

Corporate Clean Energy Targets. Corporations are facing increasing pressure from their customers and investors to align their businesses with international and national environmental and sustainability objectives, including supporting goals to reduce GHG emissions in their business operations. Leading institutional investors and money managers are increasingly considering sustainability as a key factor in investment decisions and are increasingly advocating for more transparency in disclosure on climate-related matters and pledging to align proxy voting to climate-rated proposals with its fiduciary duty. An increasing number of corporations are also proactively making commitments to reducing their GHG emissions footprint over time, either through procuring increasing amounts of clean energy or RECs to offset their carbon footprint over time. As the nation's largest producer of clean energy, we support taking bold action to address the climate change crisis and reestablish leadership in both emerging technologies and existing clean infrastructure that together will power the future.

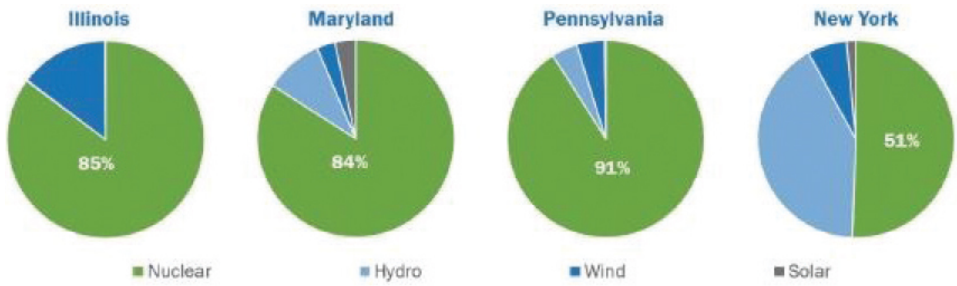
Emerging Carbon-Free Technologies. Emerging carbon-free technologies like storage and hydrogen are also expected to help accelerate the economy's de-carbonization. The U.S. added 1.1 GW / 2.6 GWh of energy storage in 2020, a significant scale-up of the market. In total, we anticipate that 13.6 GW / 35.4 GWh of storage projects will be deployed from 2021 to 2023. Lower costs, state-directed mandates, a backlog of storage projects in the interconnection queue, and utilities seeking large-scale storage capacity to support higher renewables penetration have created conditions for rapid growth of this technology in the U.S. Clean hydrogen also has the potential to drive de-carbonization, particularly as it relates to more challenging sectors like long-haul transportation, steel, chemicals, heating and long-term power storage. Nuclear power can be used to produce clean hydrogen, and our nuclear fleet positions us well to explore this emerging space. Entering the hydrogen space could provide de-carbonization alternatives and supplements to natural gas product offerings. Both energy storage and clean hydrogen continue to gain political and business support and are expected to help support net-zero carbon goals.

Policy Support for Nuclear Energy

In the current market environment, many merchant nuclear facilities are economically challenged as a result of the low near-term outlook for power prices, which has been negatively impacted by low gas prices, the influx of subsidized renewable energy generation with zero marginal production costs, over-development of new gas-fired generation and weak demand for electricity as a result of increased energy efficiency and weak economic activity. Policy support for nuclear energy recognizes that due to its strong reliability, efficiency and carbon-free nature, nuclear power will continue to play a critical role in the clean energy transition.

Our nuclear plants are meaningful contributors to the clean energy mix in the states in which they operate. States may not be able to meet their zero-carbon goals without our nuclear plants, as our plants provide a significant portion of the current carbon-free power. According to the Nuclear Energy Institute and the U.S. Department of Energy, a typical 1,000 MW nuclear facility in the United States needs just over 1 square mile to operate, whereas wind farms and solar plants respectively require 360 and 75 times more land area to produce the same electricity. Producing the same amount of power as a typical commercial nuclear reactor would require over 3 million solar panels or over 430 utility-scale wind turbines. This disparity highlights that nuclear is currently the only baseload, carbon-free solution of scale.

Current Carbon-Free Power Mix in Key States[(a)]



(a) Source: 2020 U.S. Energy Information Administration data

Federal Policy Support for Nuclear Generation. Given the Administration's aggressive goals for reducing emissions within the electric power sector, policymakers have recognized the urgent need to prevent the retirement of nuclear power plants prior to the end of their licensed lives. Nuclear energy provides 20 percent of the nation's electricity and over 50 percent of the nation's carbon free power. A dozen nuclear reactors have closed in recent years, primarily as a result of economic challenges in merchant power markets. Representative Bill Pascrell (D-NJ) and Senator Ben Cardin (D-MD) have introduced legislation to provide a $15/megawatt hour production tax credit for merchant nuclear power plants. The amount of the PTC is decreased for plants with revenues exceeding $25/megawatt hour. The U.S. Treasury Department proposed an allocated production tax credit for nuclear plants as part of their annual "Green Book" compilation of tax priorities for the Administration. The outlook for this legislation is directly tied to action on legislation extending other clean energy tax credits and remains uncertain.

State Policy Support for Nuclear Generation. A number of states in which our nuclear facilities operate have established policies to support nuclear generation. The supportive policies are driven by a number of factors, including recognition by governments and policy makers that existing nuclear generation facilities are essential to meeting policy objectives on reduction of GHG emissions, the desire to support jobs and regional economies, and the need to ensure reliability and security of the electrical grid through resource diversity.

Illinois Zero Emission Standard and Carbon Mitigation Credit Procurement. Pursuant to FEJA, on January 25, 2018, the ICC announced that our 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. We executed the ZEC procurement contracts with Illinois utilities, effective January 26, 2018, and began recognizing revenue with compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. The ZEC price was initially established at $16.50 per MWh of production, subject to annual future adjustments determined by the IPA for specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices. Illinois utilities are required to purchase all ZECs delivered by the zero-emissions nuclear powered generating facilities, subject to annual cost caps.

On September 15, 2021, Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorizes the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for carbon-free attributes of eligible nuclear power plants in PJM. Our Byron, Dresden, and Braidwood nuclear plants located in Illinois were eligible to participate in the CMC procurement process and were awarded contracts to sell their respective CMCs in an amount equivalent to their full output to ComEd for a term of 5 years staring on June 1, 2022, committing them to operate through May 31, 2027. The price to be paid for each CMC was determined through a competitive bidding process that includes consumer-protection measures that cap the maximum acceptable bid amount and reduce CMC prices by an energy price index, the base residual auction capacity price in the ComEd zone of PJM, and the monetized value of any federal tax credit or other subsidy if applicable. Regulatory or legal challenges regarding the validity or implementation of the Clean Energy Law are possible and we cannot reasonably predict the outcome of any such challenges.

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that provides 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 legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey will be required to purchase those ZECs. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. On October 1, 2020, PSEG and Generation filed applications seeking ZECs for the second eligibility period (June 2022 through May 2025). On April 27, 2021 the NJBPU approved the award of ZECs to Salem 1 and Salem 2 for the second eligibility period, with the subsidy extended at $10 per MWh.

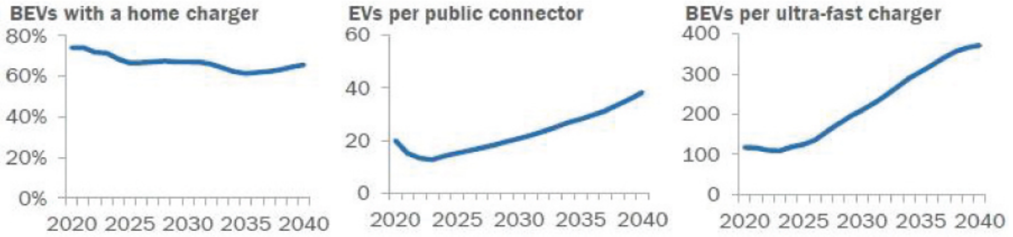
New York Clean Energy Standard. On August 1, 2016, the NYPSC issued an order establishing the New York CES, a component of which is a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity. The NYPSC has determined that our FitzPatrick, Ginna and Nine Mile Point nuclear facilities meet the criteria. The New York State Energy Research and Development Authority (NYSERDA) centrally procures the ZECs through a 12-year contract extending from April 1, 2017 through March 31, 2029, administered in six two-year tranches. ZEC payments are made based upon the number of MWh produced by each facility, subject to specified caps and minimum performance requirements. The ZEC price for the first tranche was set at $17.48 per MWh of production and is administratively determined using a formula based on the social cost of carbon as determined in 2016 by the federal government, subject to pricing adjustments designed to lower the ZEC price based on increases in underlying energy and capacity prices. Following the first tranche, the price will be updated bi-annually. The ZEC price for the third tranche was set at $21.38 per MWh and took effect on April 1, 2021. The next update is scheduled to occur on April 1, 2023. Each Load Serving Entity (LSE) is required to purchase an amount of ZECs from NYSERDA equivalent to its load ratio share of the total electric energy in the New York Control Area.

Electrification

The push to reduce or eliminate GHG emissions could lead to acceleration of the electrification of the U.S. economy, including electrification of transportation, industrial operations, heating and cooling, and appliances, which could materially increase demand for electricity. Widespread electrification could increase 2050 U.S. electricity consumption by between 20% and 38%. Higher demand for electricity will likely drive higher prices and benefit our business. We expect reliable, baseload nuclear power will be essential to meeting increased demand, well-positioning our fleet to benefit from the electrification of the U.S. economy.

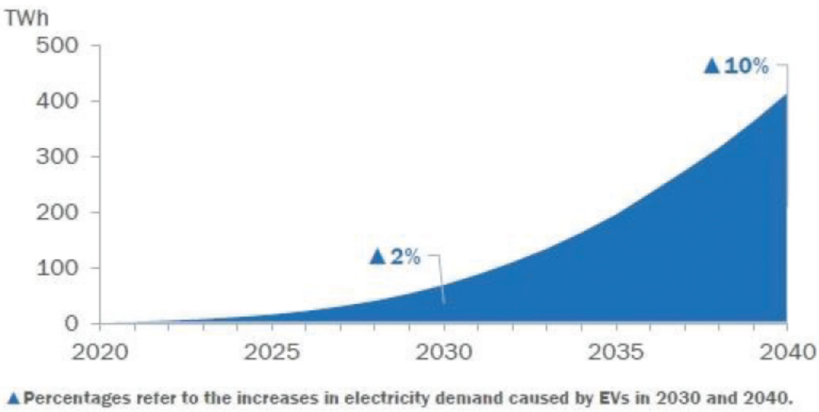
Although EV sales in North America are well behind Europe and China, increased policy support from the Biden administration, together with a number of electric pickup trucks and SUVs, including hybrid EVs, hitting the market over the next five years will drive the U.S. market in 2021 and beyond. Beginning in 2021, U.S. consumers will have a stronger EV lineup to choose from, including EVs from prominent producers like Tesla, Rivian, Nissan, Ford, Audi, GMC, Hyundai, and Volkswagen, among others. For example, in January 2021, General Motors announced a goal to phase out gas and diesel-powered vehicles by 2035, which account for roughly 98% of their sales today. With over 90% of states offering incentives for setting up EV charging infrastructure, U.S. EV market sales are projected to rise to 6.9 million units by 2025.

U.S. Passenger EV Charging Infrastructure Demand[(a)]



(a) Source: Bloomberg NEF Electric Vehicle Outlook 2020. Note: BEV = Battery Electric Vehicle

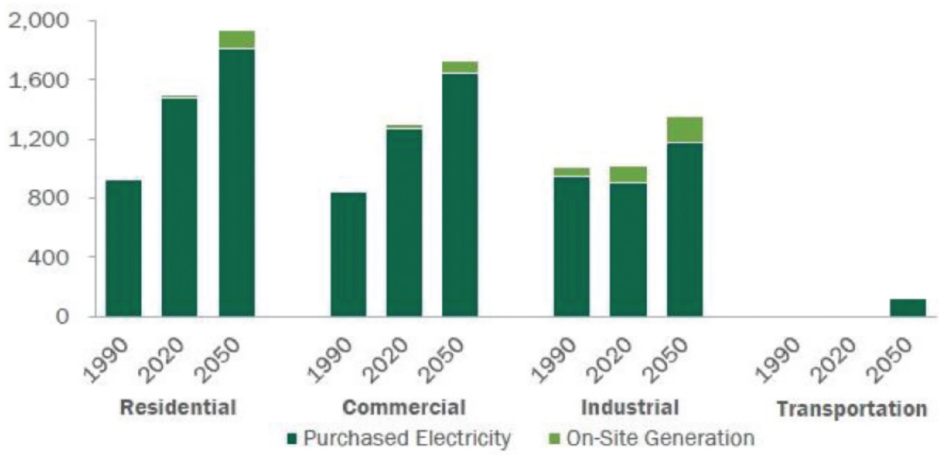
U.S. EV Electricity Demand Outlook[(a)]



(a) Source: Bloomberg NEF Electric Vehicle Outlook 2020. Note: BEV = Battery Electric Vehicle

Electrification of industrial processes, commercial equipment and residential appliances that currently run on fossil fuels will also play a role in increasing the net demand for electricity. This trend is likely to be driven by increased corporate, investor, and customer focus on sustainability, as well as by an underlying need to increase efficiencies and manage operational costs. Electric systems tend to be relatively more efficient than existing systems, including having a higher performance lifetime and relatively superior design, yield, process controllability, and flexibility. As the costs of renewables, including energy storage, continue to decline, it is likely reducing energy and overhead costs will also be a driving factor towards the electrification of industrial processes and operations. Conversion of heating systems that currently run on gas and oil represents another potential source of increased demand for electricity. According to the International Energy Agency, heat makes up two-thirds of industrial energy demand, and almost one-fifth of global energy consumption, prompting efforts by energy companies and industrial manufacturers to electrify their thermal processes. For companies like us whose core competency is safely generating and serving electricity and related products to its customers, this increasing trend toward electrification provides natural growth opportunities.

U.S. Electricity Use by End-Use Sector | TWh[(a)]



(a) Source: U.S. Energy Information Administration, Annual Energy Outlook 2021 (Feb 2021). Reflects the AEO2021 Reference Case.

Evolving Customer Preferences

Evolving customer preferences that favor additional clean energy solutions, choice and access through increased digitization, will impact the commercial power and natural gas (or energy) industry. Recent key trends include: (i) consumer preferences for additionality (i.e., meeting sustainability goals by adding incremental renewable resources to the grid instead of utilizing existing spare capacity), (ii) the ability to be connected to, trace and validate the source of their green energy choices, (iii) value-add services and products around their energy usage, and (iv) the ability to buy, manage and measure their energy usage digitally. Today’s power markets provide the ability to offer more customized energy solutions and green products to better address and serve the demands of customers today.

Under de-carbonization, customer preferences for additionality to meet sustainability goals through adding incremental renewable resources to the grid will contribute to greater buildout of renewables. Consumers are also increasingly purpose-driven and knowledgeable of services that drive de-carbonization, leading them to value the ability to be connected to and trace the source of their clean energy choices. A third-party study found that 60% of consumers have become more aware of climate change since the start of the COVID-19 pandemic, with more than half of consumers likely to invest and upgrade to energy efficiency programs today than before.

Growing awareness of climate change and green energy helps drive customer interest in value-add services and products around their energy usage, such as residential rooftop solar, EV charging, smart, energy-efficient home technologies, and the ability to choose 100 percent clean power in competitive retail energy markets. Developments in power technology and automation mean that the relationship between the customer and the understanding of how they manage their energy is now more connected through digital applications. Increasingly, affordable technologies and the growing availability of smart meter data are facilitating customers’ ability to make a range of unprecedented energy choices. A third-party study found that more than half of customers are interested in time-of-use tariffs / flexible tariffs / demand-response options to increase cost savings by shifting their electricity consumption from evenings to daytime / nights.

With the digitization of the broader economy, customers and businesses at each purchasing entry point level have increased desire for flexibility to directly engage in their buy decisions electronically, as well as manage their energy usage digitally in real time. Digital marketplaces and monitoring systems will facilitate greater control and opportunities for customers and businesses to more frequently engage with their energy providers and become more knowledgeable of their energy choices, including the products we provide.

Responding to these evolving customer preferences will facilitate continued innovation in the commercial power space and new opportunities for providers to connect energy decision making more directly to the end-user.

OUR BUSINESS

Our Company is America’s leading clean energy company, based on the production of carbon-free electricity. We are the largest supplier of clean energy and sustainable solutions to homes, businesses, public sector, community aggregations and a range of wholesale customers (such as municipalities, cooperatives, and other strategics) across the continental U.S., backed by approximately 33,000 megawatts of generating capacity consisting of nuclear, wind, solar, natural gas and hydro assets. In 2020, the Company produced nearly 12% of the nation’s carbon-free energy (based on generation output of electricity) according to published reports on energy delivery by the U.S. Energy Information Administration, making it an important partner to business and state and local governments that are setting ambitious carbon-reduction goals and seeking long-term solutions to the climate crisis.

The Company is comprised of two primary business units: Constellation NewEnergy, Inc. and Exelon Generation Company, LLC. The combined Company operates in 48 states, Canada and the U.K. and employs approximately 12,500 people.

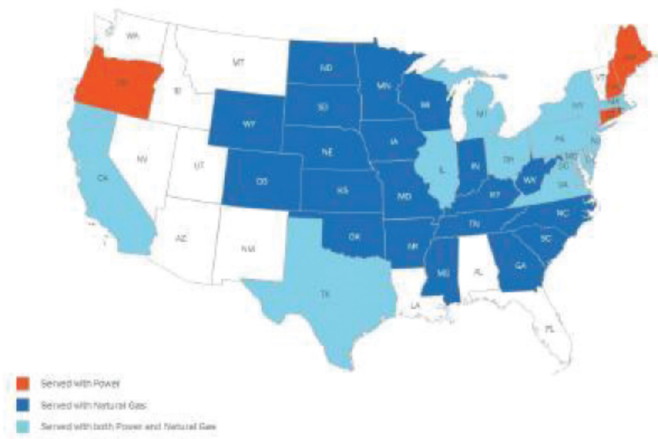
We believe shareholder value is built on a foundation of operational excellence and the pairing of our customer facing platform with our clean energy fleet. We are committed to maintaining investment grade credit ratings. We are focused on optimizing cash returns through a disciplined approach to cost management and efficient operations, underpinned by stable and durable margins from our customer-facing business coupled with visible generation payments associated with our clean energy attributes. We are committed to maintaining a strong balance sheet, to returning value to our shareholders (subject to approval by our Board of Directors) and to investing in clean energy solutions.

Our Operations

Customer-Facing Business: Constellation

Constellation is one of the nation’s largest and most innovative energy suppliers, serving customers of all sizes through the U.S. Constellation is active in all domestic wholesale power and gas markets that span the entire lower 48 states and has complementary retail activity across many of those states.

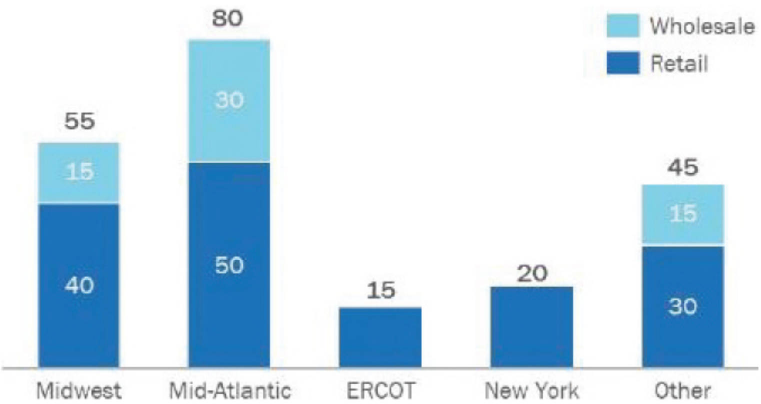
Constellation Retail has a Diverse Geographic Footprint



Power Supply

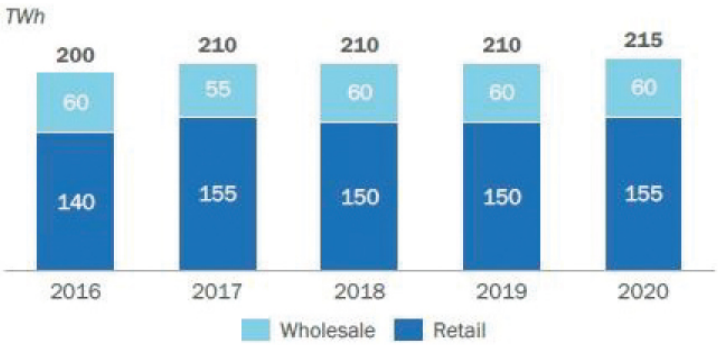
Constellation is a leader in power supply serving 215 TWhs annually to a diverse geographic customer base, including utilities, municipality, cooperatives, commercial, industrial, residential, public sector and three-fourths of the Fortune 100 companies. It is the largest retail commercial and industrial power provider and the third largest residential power provider in the U.S., supplying approximately 145 TWh to business and public sector customers and approximately 10 TWh to residential customers.

Power Load is Served Across Regions[(a)]



(a) Includes retail and wholesale load auction volumes only. Other includes New England, South and West.

Constellation is Defined by Consistent Load, Enabling Strong Cash Flows[(a)]



(a) Reflects retail load and wholesale load auction volumes as of December 31, 2020.

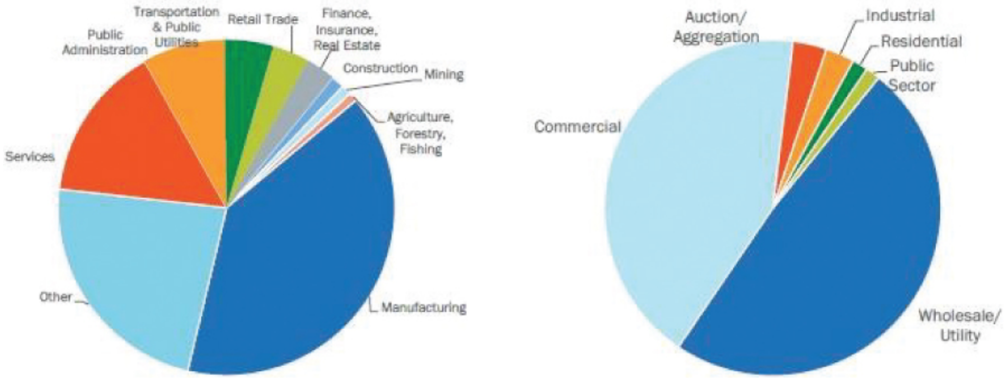
Constellation's wholesale channel-to-market serves approximately 60 TWh of power load across competitive utility load procurements and bilateral sales to municipalities, coops, banks, and other wholesale entities. Complementary to its national portfolio, Constellation has several decades of relationships with wholesale counterparties across all domestic power markets as a means of both monetizing its own generation, as well as sourcing contracted generation to meet customer and portfolio needs. With the increased trend toward customer demand for sustainability, this ability to source contracted generation has provided a capital-light way for the Company to provide customers with the renewable products they are demanding to support a cleaner energy ecosystem. This creates durable customer relationships and repeatable business through the ability to respond to customer and marketplace trends. Similarly, this contracting acumen provides the ability to supplement our native generation with other non-renewable assets to meet changing portfolio needs in a balance sheet efficient manner.

Gas Supply

Constellation is also a leader in gas supply serving 1,600 Bcf of gas annually to a wide range of residential, commercial, wholesale, and municipal customers across many sectors, including manufacturing, services, public sector, transportation, and utilities. Because we have an integrated gas business that focuses not only on supplying customer needs, but also providing fuel for our power plants and sourcing Liquefied Natural Gas (LNG) for the Everett Marine LNG Import Terminal, we have strong capabilities across the entire natural gas value chain allowing us to optimize our portfolio to provide both low cost and customized solutions to our customers. Similarly, the scope of our natural gas business provides us wide geographic coverage across all domestic natural gas markets.

In addition to providing energy management strategies that focus on more than just price, customers are able to focus on actively managing costs, mitigating risk and supporting long-term budget certainty. Constellation's gas managed products are designed to minimize volatility and achieve budget certainty over time, while providing customers the ability to create a structured plan that reduces the pressure to capture the lowest price to create protection from volatility. It is the breadth of offerings, experience across the value chain, and customer and geographic diversity that contribute to the robust cash flows derived from the gas business. Constellation is committed to the ongoing sustainability needs of gas customers by providing renewable energy products and solutions as options to reduce carbon emissions through Renewable Natural Gas (RNG) and Carbon Offsets for natural gas consumption. Similarly, due to the tight interrelationship between natural gas and electricity markets, Constellation's natural gas business also provides valuable market intelligence useful to our overall business.

2020 Constellation Gas Sales by Market Sector and Customer Type



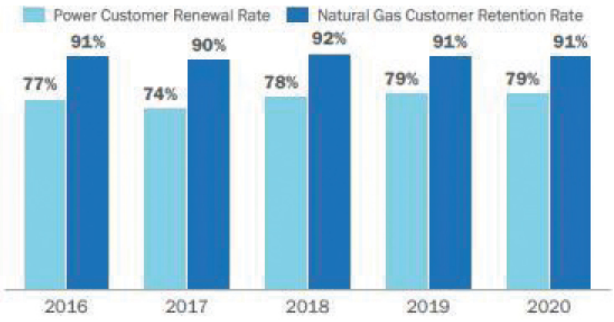
Customer Acquisition and Retention

Constellation primarily serves C&I customers across the United States. These strong, proven customer relationships are a key part of our customer-facing business strategy. High customer satisfaction levels, market expertise, stability and scale drive growth and result in historically-proven business consistency and margins. Customer retention rates have been strong over the last five years across C&I power customer groups, with average contract terms of 25 months and customer duration of more than six years, with many customers beyond these metrics. Specifically, Constellation enjoyed a 79% C&I power, a 91% C&I gas, and 78% power and gas residential renewal rate in 2020, consistent with the previous four years, owing to both its competitive pricing as well as its strong customer relationships. Our consistently high renewal rates are driven by our ability to provide customized solutions and deliver focused attention to our customers' needs, resulting in industry-leading customer satisfaction. Constellation is successful at acquiring new customers by offering a diversity of innovative services and products, meeting customers where they are in the buying cycle. In addition to our high customer retention rates, we are able to acquire nearly one out of every three customers who have chosen to shop. While providing customers with the best possible price is a key focus, Constellation leverages its broad suite of electric and gas product structures, oftentimes customized, to provide customers with the commodity solution that best fits their needs. It is this attention to the customer that creates the durable, repeatable value highlighted in these statistics.

Consumer purchasing strategies have trended from direct supply relationships to third party relationships with a growing number of customers looking to third party consultants to find suppliers like

Constellation to reduce costs and evaluate the increasing number of options available for expanding energy solutions beyond commodity. Constellation has seen its third-party sourced business grow from approximately 42% of its C&I Power load to 64% between 2014 and 2020, and 20% of its C&I Gas load to 40% during the same period. In response, Constellation expanded its third-party capabilities, created scale through a comprehensive support structure, and enhanced digital applications providing tools, tracking and measurement as well as the ability to extend the reach of Constellation's sustainability services and products to drive additional market share.

Constellation Benefits From Strong Customer Relationships, with Leading C&I Renewal Rates



Energy Solutions

As one of the largest customer-facing platforms in the U.S., Constellation benefits from significant economies of scale, which allow us to provide our customers with competitively priced energy and to structure highly tailored solutions targeted to a customer's unique power needs and clean energy goals. Our customer solutions include specialty power and gas products matching customers' risk tolerance and risk management needs, energy efficiency, carbon free products for power and gas (RECs, EFECs, RINs, carbon offsets), energy usage and management solutions, among others. Our volumes across multiple products and markets also provide us with unique market intelligence and expertise, including visibility into emerging trends and opportunities to identify new revenue opportunities and to capture incremental margin. Similarly, the scale and scope of the portfolio provides risk-mitigating product and geographic diversification. The scale of our industry-leading national platform also allows for quick and effective integration of new customers and acquisitions, accelerating the impact of strategic growth to the bottom-line.

Constellation is a leader in enabling a clean energy future for its customers through innovative purchasing strategies that expand beyond power and natural gas. Constellation partners with its customers to provide options along the sustainability continuum, including, renewable, efficiency and technology applications to meet their carbon free energy goals. Constellation offers a suite of services and products to its power and gas customers that can be integrated into existing commodity purchasing strategies. Constellation is viewed as a center of excellence for customers looking to evaluate, understand and incorporate innovative solutions, products or technology into their existing energy strategy.

Constellation energy efficiency products provide the ability to optimize performance and maximize efficiency across customer facilities and operations through attractive contract structures including implementation of energy efficiency upgrades at no upfront capital requirements. Additionally, these services provide scalable solutions to meet sustainability goals through investment across the life of the facility or operations and allow for budget certainty. The ongoing ability to optimize energy consumption for customers allows Constellation to support customer demands with the right combination of technology and efficiency program options.

Constellation also offers Pear.ai, a smart utility expense management platform that helps customers proactively manage utility costs, understand trends, and develop strategies to optimize spend and drive sustainability objectives. Pear.ai allows Constellation new avenues to incremental growth by coupling the opportunities for customer usage optimization with accompanying products and solutions that Constellation can provide the customer. Services like Pear.ai allow Constellation to grow its customer base in previously inaccessible regulated markets through the offering of non-commodity energy products.

Further, our CORe (Constellation Offsite Renewables) product serves C&I customer's sustainability needs by matching contracted, third-party renewable generation with customer desire for additional solutions and geographic preference. In addition to larger-scale CORe offerings, Constellation offers a range of sustainability attribute solutions to its customers (RECs, EFECs, RINs, carbon offsets, etc.) in order to support their energy needs during the transition to a cleaner energy ecosystem.

Constellation Technology Ventures' commercialization team collaborates with portfolio companies to deploy products and technologies across our broad customer base to drive value for both Constellation and portfolio companies. Portfolio company solutions include electric vehicles and charging infrastructure, sustainability monitoring and reporting tools, distributed energy resources and financing solutions, a web-based energy marketplace, and more. For example, Constellation Technology Ventures' commercialization of ChargePoint, a company providing a network of electric vehicle charging stations, demonstrates our commitment to the electrification trend and immediately scalable channels-to-market for technology solutions to create value for our customers. Future growth will be driven from new and growing digital channels with a focus on innovative products aimed at clean energy solutions. New products and strategic investments will help our customers positively impact the environment, yield strong customer retention rates, and open up additional revenue opportunities to supplement existing, economically beneficial products with solid margins.

Generation

Generation operates the largest zero-carbon fleet in the nation and one of the largest generating fleets in the country.

Generation's nuclear fleet has current generating capacity of approximately 19 gigawatts and produced 150 terawatt hours of zero-emissions electricity during 2020 — enough to power 13.6 million homes and avoid more than 106 million metric tons of carbon emissions. Generation has ownership interests in thirteen nuclear generating stations currently in service, consisting of 23 units. Generation wholly owns all of its nuclear generating stations, except for undivided ownership interests in three jointly-owned nuclear stations, Quad Cities (75% ownership), Peach Bottom (50% ownership), and Salem (42.59% ownership), and Nine Mile Point Unit 2 (82% undivided ownership interest).

Generation will continue to be a leading advocate for clean energy policies aimed at preserving and growing clean energy to combat the climate crisis.

Generation operates the nation's largest fleet of nuclear power plants and consistently operates at best in class levels. In 2020, Generation recorded a capacity factor of 95.4%, second only to 2019 performance in fleet history, and an average refueling outage duration of 22 days, 11 days better than the industry average. More broadly, the nuclear capacity factor has been approximately four percentage points better than the industry average annually since 2013. Our stations exclude TMI located in Middletown, Pennsylvania, which permanently ceased generation operations on September 20, 2019 and Oyster Creek located in Forked River, New Jersey, which permanently ceased generation operations on September 17, 2018 and was subsequently sold to Holtec International (Holtec) on July 1, 2019.

We operate more than 12 gigawatts of natural gas, oil, hydroelectric, wind, and solar generation assets, which provide a mix of baseload, intermediate, and peak power generation. Our fossil and renewable fleet has similarly demonstrated a track record of strong performance with a 98.4% power dispatch match and 93.4% renewables energy capture.

Collectively, the combined fleet is nearly 90% carbon-free (based on generation output of electricity) and represents the fourth largest generation portfolio in the U.S. in terms of total generation with meaningful geographic diversity.

The charts below illustrate our supply source as of December 31, 2020:

Supply Source[(a)(b)]

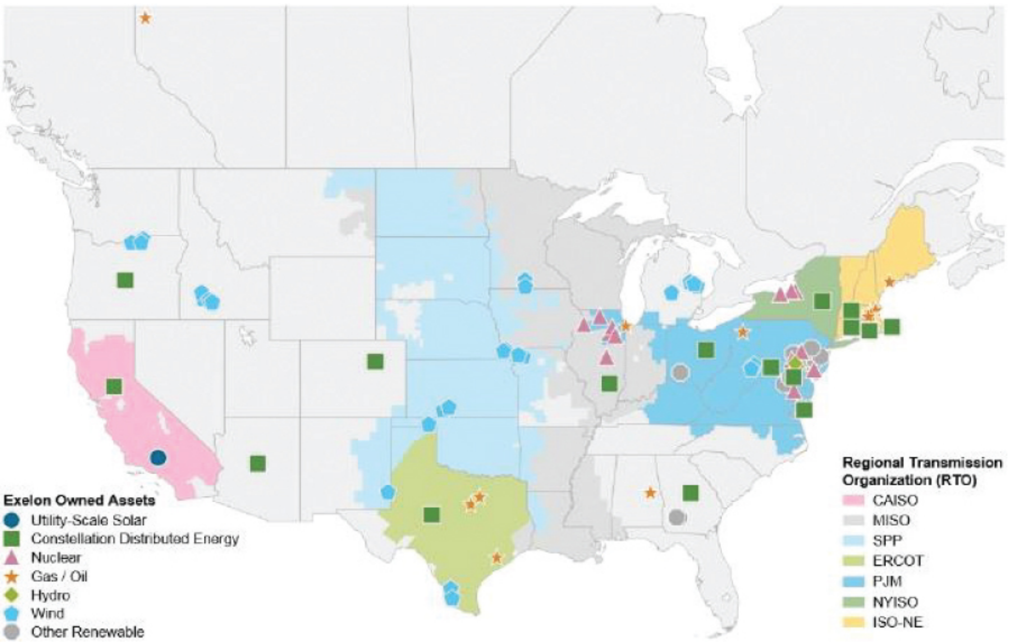
	Generation Output	
	Gwh	%
Nuclear	175,085	62.2%
Fossil (primarily natural gas and oil)	19,501	6.9%
Renewable	7,052	2.5%
Purchased Power	79,972	28.4%
Total	**281,610**	**100%**

(a) Nuclear 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.

(b) Renewable includes wind, hydroelectric, solar, and biomass generating assets.

The following map illustrates the locations of our generation facilities as of March 31, 2021:

The Company's Generation Fleet Map[(a)]



(a) Note: One symbol is included per location. Some locations may have multiple generating units. Locations in tight geographic proximity may appear as one symbol. Units that are not currently operational are not captured.

Constellation employs an integrated, ratable hedging strategy to manage energy price volatility over time. As a policy, we hedge commodity risk on a ratable basis over a rolling three-year period to reduce the financial impact of market price volatility. Constellation uses a combination of wholesale and retail customer load sales, as well as non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. The scale of our generation portfolio, along with its geographic proximity to our load, allows us to lean heavily on a generation-to-load matching strategy to structurally hedge energy price risk. This helps to mitigate incremental collateral needs to serve load, while still allowing flexibility to serve and grow our customer business. As of September 30, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 96% – 99% for the remainder of 2021. The Generation portfolio has enjoyed more than a decade of a
risk-mitigated ratable hedging strategy, whereby the prompt three years are hedged on an approximate rolling 90% / 60% / 30% basis, providing cash flow stability for its investors, while still allowing commercial opportunities to generate value for the enterprise. Constellation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk.

We have a scale presence in key markets, allowing us to operate integrated portfolios and capture operational synergies, including allocation of fixed costs across a broader asset base, enhanced procurement opportunities, and diversity of cash flows. These advantages, in combination with a strong balance sheet and significant liquidity, enable us to operate with more financial flexibility, and as such, optimize our competitive scale and operations.

Management

Although we have not yet finalized the full composition of our board of directors (the "*Company Board*") following the separation, we expect that the following individuals, each of which currently serve on the Exelon board of directors, will resign from the Exelon board of directors (the "*Exelon Board*") and serve on the Company Board as of the distribution date: Joseph Dominguez, Yves de Balmann, Laurie Brlas, Robert Lawless and John Richardson. The executive officers will include: Joseph Dominguez, Daniel Eggers, Kathleen Barrón, Bryan Hanson, Mike Koehler, James McHugh, and David Dardis. See "Management" for information on our executive officers and board of directors.

Our Competitive Strengths

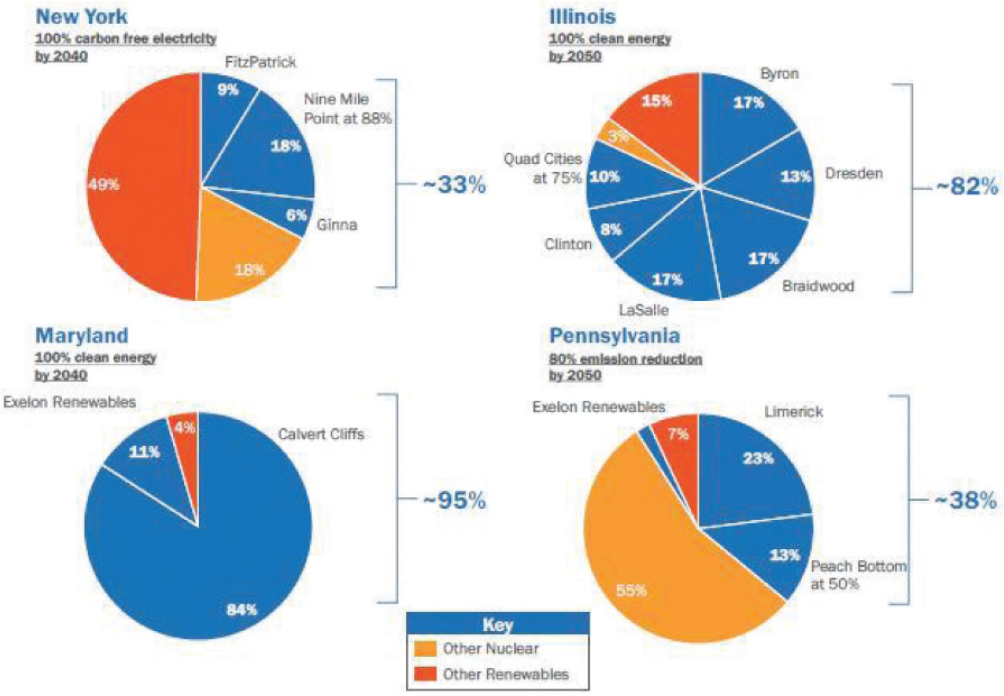
We believe that we are well-positioned to execute our business strategy and create superior value for stakeholders based on the following competitive strengths:

- ***We are positioned to help address the climate crisis and lead to a clean energy future***

As a Company, we are committed to a clean energy future, and we believe our generation fleet is essential to helping meet clean energy policy and targets, at either the state or national level. Approximately 90% of our generation fleet energy output is emissions free (based on generation output), and we do not own coal-fired generation. According to the July 2021 Benchmarking Air Emission report, our Company produces approximately 65% more clean energy than the next leading provider. Our fleet has the lowest emissions intensity — nearly five times less intensive than the next lowest generator.

Our generation fleet is essential to meeting federal and state clean energy goals. Generation produced 12% of the zero-carbon energy nationwide and even more in the states we operate in — 95% in Maryland, 82% in Illinois, 38% in Pennsylvania and 33% in New York. Each state has set decarbonization and clean energy targets. Losing any of our clean assets in these states would be a significant step backward for achieving any clean energy or climate goals while also creating higher costs for customers and significant economic hardship for our plant communities.

Generation Plays a Central Role in Enabling States' Respective Clean Energy Goals[(a)(b)]



(a) Source: 2020 U.S. Energy Information Administration data. Assumes whole unit output of CENG generation. Does not adjust for announced retirements by Company at Byron and Dresden in Illinois and retirement by another operator of Indian Point 3 nuclear unit in New York. Note: Renewables includes hydroelectric, solar, and wind generation and excludes biomass. Reflects clean energy goals as outlined in the state's existing law or goal established by the state Governor.

(b) Generation owns an 82% undivided ownership interest in Nine Mile Point Unit 2.

We believe these attributes are a clear advantage for us as the federal government and our states pursue policies that will address the climate crisis and a clean energy future. The Company will continue to be a leading advocate for these clean policies aimed at preserving and growing clean energy.

In addition to preserving the environmental value that our existing generating fleet provides, Constellation is committed to further development of customer-focused products and capabilities that provide clean energy solutions across the power, gas, and broader energy solutions spaces. Whether through venture investing via Constellation Technology Ventures, R&D efforts or expansion of our clean products for customers, commercialization of more mature technologies or leveraging our innovation culture, we will proactively drive a clean energy future with our customers.

- ***Industry-leading customer-facing business providing sustainability solutions for our customers***

Geographic scale, diversity, customer-tailored product offerings and services and high customer satisfaction underpin our robust customer-facing platform and allow us to partner with customers to solve their emerging needs on their clean energy goals in a differentiated way.

Constellation is the largest customer facing platform in the U.S., which we view as a source of considerable competitive advantage. Our industry-leading national platform not only allows us to capture operational efficiencies for more effective integration of new customers and acquisitions, but also allows for a scalable go-to-market approach. This allows for rapid deployment of new energy services and products and innovative energy technology applications that are responsive to marketplace trends and demands, improving our position for growth.

Constellation's heavy customer concentration in the C&I retail space, coupled with high customer satisfaction, further differentiates the business within the competitive landscape in its ability to provide repeatable, derisked value to the shareholder. Customer concentration in C&I enables more predictable load and stable unit margins, lower customer acquisition costs, and insulation from weather driven volatility. Cash flows are further maximized by high customer satisfaction levels resulting in business consistency, stable unit economics, and high win and renewal rates. Since 2016, the Company has achieved retail renewal rates in excess of 70% (74 – 79% for C&I Power, 90 – 92% for C&I Gas), and the average customer duration has been six years.

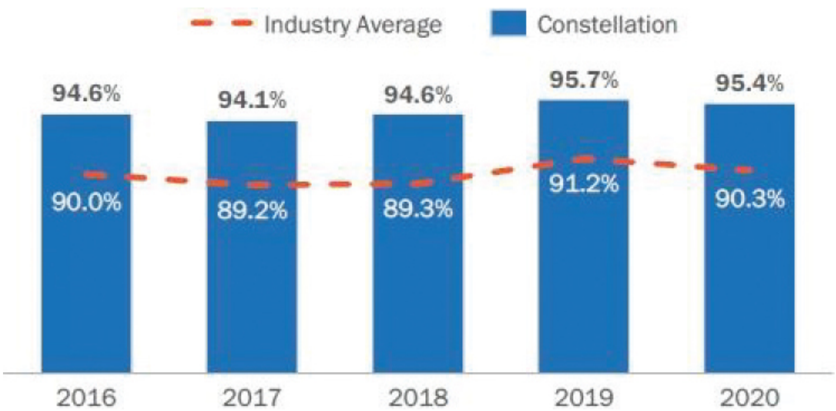
Another advantage is Constellation's industry leadership in consistently developing and providing clean energy and sustainability solutions for our customers. Partnering with our customers to help them meet their environmental and sustainability goals provides us with solid margins, contributes to strong customer retention rates, and opens up additional revenue opportunities.

- ***Best-in-class nuclear operations***

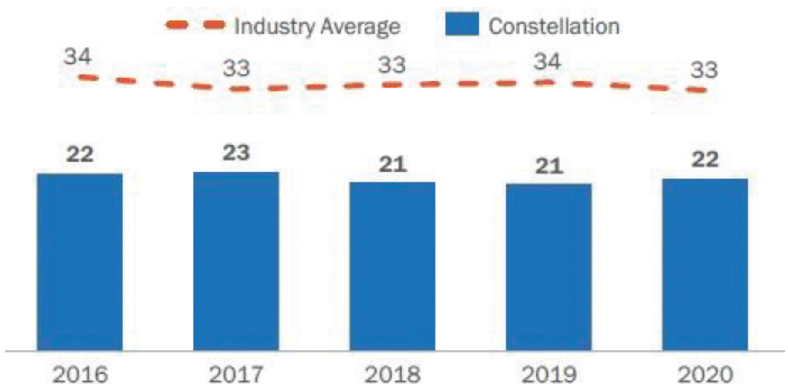
Our world class operations result in industry-leading operating performance at our generation facilities. Our generation fleet has achieved an industry-leading nuclear capacity factor of approximately 94% or higher since 2013, four percentage points better than the 2020 industry average of approximately 90%. Our 2020 average refueling outage duration was 22 days, 11 days better than the industry average.

Generation is Defined by Best-in-class Operating Performance

Nuclear Capacity Factor[a]



Average Nuclear Refueling Outage Days[b]



(a) Reflects the Company's ownership share of partially owned units. Includes Fitzpatrick beginning in April of 2017, and Oyster Creek and TMI partial year operation in 2018 and 2019, respectively. Excludes Salem and Fort Calhoun. Industry average is for major operators excluding Generation and includes 3 months of Fitzpatrick prior to Generation's acquisition.

(b) Reflects partially owned units at 100% ownership share. Includes Fitzpatrick beginning in 2018. Excludes Salem. Industry average reflects nuclear refueling outage days as tracked by the Nuclear Energy Institute.

- ***Disciplined financial management focused on strong balance sheet and optimizing cash returns***

Our continued commitment to investment grade credit ratings remains paramount as we prioritize capital allocation to support a strong balance sheet, invest in both clean energy solutions and our customer-facing businesses, and return value to shareholders. Our financial policy, focused on a prudent hedging strategy and effective cost management, provides us with financial flexibility, reduces the volatility of our cash flows and enables more efficient utilization of both working capital and collateral to operate the business through all cycles.

We view a strong balance sheet as a competitive strength in managing through periods of commodity price volatility with heightened agility. We are focused on allocating available cash flow to manage leverage to meet investment grade targets with incremental cash flows allocated to investing in both clean energy solutions and our customer-facing businesses and returning capital to shareholders. We believe a strong balance sheet and robust cash flow generation, combined with our current presence and scale in diverse markets, will position us favorably in pursuit of value-enhancing growth opportunities.

With high customer satisfaction, strong customer renewal and retention and best-in-class operating expertise, we are well-positioned to deliver strong cash flows. To further support cash flow, we will continue to focus on operational efficiencies and cost management while ensuring the safety and reliability of our operations. In addition, our integrated and ratable hedging activities serve to manage commodity price volatility in energy gross margins over time. Finally, state payments for our fleet's carbon-free attributes and capacity payments provide visibility and consistency of cash flows. We believe the stability of our cash flow, coupled with our investment grade rating, provides a competitive advantage by improving resilience during market fluctuations, decreasing reliance on external funding through low financial leverage and positioning the business for growth.

- ***Committed to supporting all stakeholders through a strong commitment to environmental, social and governance practices***

We are committed to the highest standards of corporate governance to help us achieve our performance goals and to maintain the trust and confidence of our shareholders, employees, customers, regulators and other stakeholders. Environmental, Social and Governance principles have been at the core of our business since its original founding and will continue to be core to the Company.

We will continue to support our diverse employees, customers, communities and business partners, ensuring all are able to fully and equitably participate in social, environmental and economic progress. We will maintain the highest standards of corporate governance, operating responsibly and transparently with a continued focus on board refreshment and diversity.

Our Business Strategy

Our business strategy is to maximize value for all of our stakeholders through a particular emphasis on:

Focus on cash returns, business optimization, robust customer revenues, and capital allocation

We run our business with a focus on producing strong, robust cash flows in order to sustain our operations, maintain our investment grade credit targets, and fund shareholder return and growth opportunities. We remain focused on operating efficiency and cost management, while ensuring safety and operational excellence, to support stability in free cash flow generation.

We aim to achieve growth in cash flows from our customer facing business by increasing volumes and driving margin improvement across all channels to market. Increasing volumes can come from organic and acquisitive customer growth, both in commodity offerings as well as reaching previously inaccessible customers through non-commodity energy services and solutions. Increasing margins are expected to come from value-add products, services, and analytics coupled with existing offerings. Additionally, customer loyalty increases with the number of products and services we provide, contributing to repeatable, derisked cash flows. Constellation is a leader in enabling a clean energy future for its customers through informative purchasing strategies that expand beyond power and natural gas, focused on renewable, efficiency and technology applications to meet their carbon free energy goals. We will continue to target growth in volumes through both organic growth channels and disciplined mergers and acquisitions. We can leverage our existing platform to achieve economies of scale benefits on incremental volumes, leading to higher overall margins per customer and improved free cash flow conversion. Cash flows are further maximized by high customer satisfaction levels resulting in business consistency, stable unit economics, and high win and renewal rates. We will continue to manage cash flow volatility through prudent risk management strategies across the customer facing business, as described later in this document.

We also aim to achieve growth in cash flows from our generation business through a rigorous focus on operating performance and cost optimization. We will continue to evaluate the cost-benefit analysis of all operating and capital allocation decisions to optimize value for our stakeholders, without sacrificing our commitment to safety. Further, our ratable hedging strategies, coupled with stable revenues generated through capacity markets and contracts for zero emission attributes will enable the business to continue to mitigate cash flow volatility, while preserving long-term optionality to realize potential upside from market price improvements and/or state and federal clean energy programs. In addition, we will continue advocating for clean energy policies and seek fair compensation for the zero-carbon attributes of our nuclear plants while maintaining the discipline to retire uneconomic assets.

We will employ a disciplined approach to acquisitions that grows future cash flow and supports strategic initiatives. We will continue to evaluate asset and business divestitures to rationalize the portfolio and optimize cash proceeds.

Capital allocation decisions are made on a cash return basis, as we believe this discipline is necessary to drive consistent long-term value creation for our shareholders. We believe that our management team, reliable operating structure and strong commercial management enables us to deliver sustainable cash flows to support the balance sheet, return value to our shareholders and invest in and grow the existing platform, while achieving attractive returns on investment. In the years ahead, we expect to deliver substantial free cash flow supported by our stable customer facing business, disciplined hedging strategy and effective cost management, with more than $1.1 billion of cost reductions realized since 2015.

Financial discipline and balance sheet commitment.

We are committed to maintaining sufficient financial liquidity and an appropriate capital structure to support safe, secure and reliable operations, even in volatile market conditions. We believe our investment grade credit rating is a source of competitive advantage, and we intend to continue to maintain our credit position and best-in-class balance sheet. In line with that commitment, available cash flow will first be used to manage leverage to comfortably meet investment grade credit targets, with incremental capital allocated towards shareholder return and disciplined growth.

Excellence in operations.

Value is built on a foundation of operational excellence. We recognize operational efficiency, a culture of continuous improvement and disciplined investment, and robust safety practices as critical drivers.

We inherit robust safety programs from our predecessor company, and we have historically demonstrated a deep commitment through our exceptional safety track record, underpinned by a strong compliance and risk management culture. At the Company, we have strong, durable relationships with our customers resulting in stable financial margins, underpinned by strong operational performance in our customer-facing business. Our retail power customer renewal rates have averaged 77% since 2016 and 91% for natural gas customer retention rates.

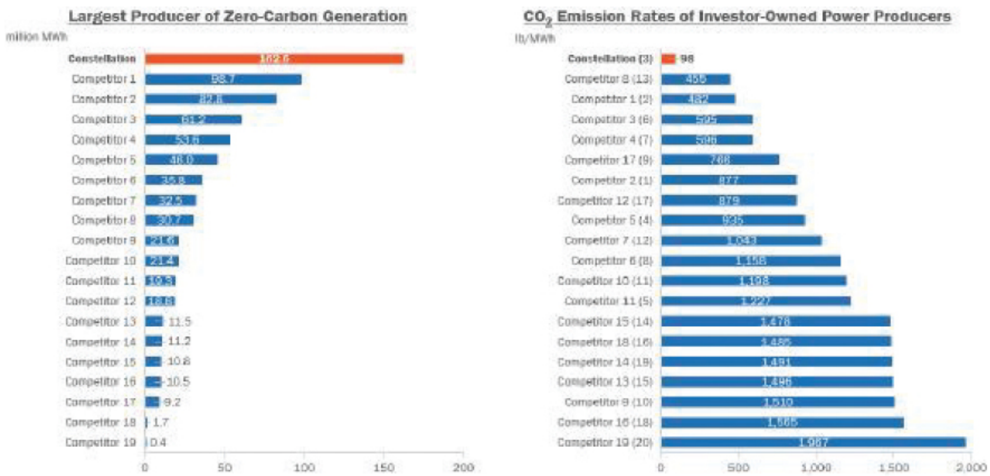
We will continue to evaluate the cost / benefit of all operating and capital allocation decisions to optimize value for our stakeholders. However, above all, we will continue to prioritize safety, which is a core value for our organization.

Taking the lead on driving toward a clean energy future.

We are committed to enabling a clean energy future through our generation operations and our customer-facing business. Through our two businesses, we aim to serve as an indispensable partner to businesses and the state and local governments that are setting ambitious carbon-reduction goals and seeking long-term solutions to the climate crisis. We advocate for policies that address the climate crisis and preserve and grow clean energy.

We are differentiated by the cleanest generation fleet in the country. Since our generation fleet is nearly 90% emissions-free (based on generation output), we would have minimal compliance costs compared to our peers.

Our Company is the Largest Producer of Clean Electricity in the U.S.[(a)]



(a) Source: Benchmarking Air Emissions, July 2021, published by M.J. Bradley & Associates LLC. Reflects 2019 regulated and non-regulated generation. Number in parentheses is the company's generation ranking in that year.

As environmental sustainability continues to build momentum and grows for businesses across the country, the demand for clean and sustainable energy solutions increases. Constellation offers clean products to help customers meet their sustainability goals. In addition to our current product offerings, we will innovate and develop new products to meet our customers' needs.

For nearly two decades, our predecessor company was a strong advocate for policies that would address the climate crisis. We will continue to be a leading advocate at the federal level and in our states for policies that will reduce greenhouse emissions and preserve and grow clean energy.

Our Key Markets

We operate across various markets in the U.S., as well as Canada and the U.K. Our generation resources allow us to generate, procure and sell electricity to retail and wholesale customers, highlighting the integrated nature of our business. We also have the ability to contract for generation in the markets in which we operate, further facilitating our ability to match generation output to customer demand (gen-to-load) and customer-to-supply as an integrated business. We have five reportable segments consisting of the Mid-Atlantic, Midwest, New York, Texas and Other Power Regions. These reflect the following geographical areas:

- Mid-Atlantic: 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: Western half of PJM and the U. S. footprint of MISO, excluding MISO's Southern Region.
- New York: NYISO
- Texas: ERCOT
- Other Power Regions: New England, South, West and Canada

Generation Markets

At December 31, 2020, our interests in net electric generating capacity totaled 31,271 MW. Our supply sources by region are summarized below:

Supply Source (GWhs)	2020
Nuclear Generation[a]	
Mid-Atlantic	52,202
Midwest	96,322
New York	26,561
Total Nuclear Generation	175,085
Fossil and Renewables	
Mid-Atlantic	2,206
Midwest	1,204
New York	4
ERCOT	11,982
Other Power Regions	11,121
Total Fossil and Renewables	26,553
Purchased Power	
Mid-Atlantic	22,487
Midwest	770
ERCOT	5,636
Other Power Regions	51,079
Total Purchased Power	79,972
Total Supply/Sales by Region	
Mid-Atlantic[b]	76,895
Midwest[b]	98,332
New York	26,565
ERCOT	17,618
Other Power Regions	62,200
Total Supply/Sales by Region	281,610

(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.

(b) Includes affiliate sales to PECO, BGE, Pepco, DPL, and ACE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.

Customer Markets

Our integrated business also consists of the physical delivery and marketing of power and natural gas across multiple geographical regions through Constellation, our customer-facing business. Constellation serves power and natural gas across all competitive markets, reaching approximately 2 million customers, including three-fourths of the Fortune 100, approximately 216,500 business and public sector customers, and about 1.6 million unique residential customers. Constellation also has a vibrant non-commodity element of its customer facing business, providing sustainability, efficiency and technology solutions to provide a comprehensive suite of energy solutions to meet customers' growing and evolving needs.

Generation Resources

Nuclear Facilities

We have ownership interests in thirteen nuclear generating stations currently in service, consisting of 23 units with an aggregate of 18,880 MW of capacity. These stations exclude TMI located in Middletown, Pennsylvania, which permanently ceased generation operations on September 20, 2019, and Oyster Creek located in Forked River, New Jersey, which permanently ceased generation operations on September 17, 2018 and was subsequently sold to Holtec International (Holtec) on July 1, 2019. We wholly own all of our nuclear generating stations, except for undivided ownership interests in four jointly-owned nuclear stations: Quad Cities (75% ownership), Peach Bottom (50% ownership), Salem (42.59% ownership) and Nine Mile Point Unit 2 (82% ownership), which are consolidated in our financial statements relative to our proportionate ownership interest in each unit.

Our nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG.

In 2020, 2019 and 2018, electric supply (in GWh) generated from the nuclear generating facilities was 62%, 64% and 68%, respectively, of our total electric supply, which also includes fossil, hydroelectric, and renewable generation and electric supply purchased for resale. Our wholesale and retail power marketing activities are, in part, supplied by the output from the nuclear generating stations.

In May 2021, PJM conducted its first annual capacity auction since May 2018 and posted the results of the 2022/2023 Delivery Year auction on June 2, 2021. All of Generation's nuclear and fossil generation power plants located in the PJM market cleared in the auction, with the exception of the Byron, Dresden and Quad Cities nuclear generation facilities. Despite also not clearing in the auction, the Quad Cities plant will continue to operate with support provided under the Illinois Future Energy Jobs Act, a clean energy law that took effect in 2017. The Minimum Offer Price Rule (MOPR) recently implemented by PJM Interconnection, L.L.C. prevented Quad Cities from clearing in the capacity auction. The result is that customers in Northern Illinois and throughout PJM will pay for more capacity from polluting generation instead of securing carbon-free megawatts from Quad Cities, at what would have been a lower cost absent the MOPR.

At the direction of the PJM Board of Managers, PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. PJM filed related tariff revisions at FERC on July 30, 2021. On September 29, 2021, PJM's proposed MOPR reforms become effective by operation of law. Under the new tariff provisions, the MOPR will no longer apply to any of our owned or jointly owned nuclear plants.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on our results of operations. Our generation operations from our nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

We manage our scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for our wholesale and retail power marketing activities. During scheduled refueling outages, we perform maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations. During 2020, 2019, and 2018, the nuclear generating facilities operated by Generation, achieved capacity factors of 95.4%, 95.7%, and 94.6%, respectively, at ownership percentage.

In addition to the maintenance and equipment upgrades performed by us during scheduled refueling outages, we have extensive operating and security procedures in place to ensure the safe operation of the nuclear units. We also have extensive safety systems in place to protect the plant, personnel, and surrounding area in the unlikely event of an accident or other incident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security, and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results and communicates its assessment on a semi-annual basis. The NRC categorizes each nuclear unit into one of five performance bands. All nuclear units operated by Generation are categorized in the Licensee Response Column (highest NRC performance band) except Clinton and FitzPatrick, which are in the Regulatory Response Column (second highest NRC performance band). The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures and/or operating costs for nuclear generating facilities.

The generation of nuclear energy results in spent nuclear fuel (SNF). SNF generated by nuclear generating facilities is currently stored in storage pools or in dry cask storage facilities. As a by-product of their operations, nuclear generating units also produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region.

Operation of nuclear generation is subject to liability, property damage and other risks associated with major incidents. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. The ultimate decommissioning obligation is expected to be funded by the NDTs.

Licenses. Generation has original 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals from the NRC for all its nuclear units except Clinton. PSEG has received 20-year operating license renewals for Salem Units 1 and 2. Peach Bottom has received a second 20-year license renewal from the NRC for Units 2 and 3. On August 27, 2020, Generation announced that it intends to permanently cease generation operations at Byron in September 2021 and at Dresden in November 2021.

The following table summarizes the current license expiration dates for Generation's operating nuclear facilities in service:

Station	**Unit**	**In-Service Date[a]**	**Current License Expiration**
Braidwood	1	1988	2046
	2	1988	2047
Byron	1	1985	2044
	2	1987	2046
Calvert Cliffs	1	1975	2034
	2	1977	2036
Clinton[b]	1	1987	2027

Station	Unit	In-Service Date[a]	Current License Expiration
Dresden	2	1970	2029
	3	1971	2031
FitzPatrick	1	1975	2034
LaSalle	1	1984	2042
	2	1984	2043
Limerick	1	1986	2044
	2	1990	2049
Nine Mile Point	1	1969	2029
	2	1988	2046
Peach Bottom	2	1974	2053
	3	1974	2054
Quad Cities	1	1973	2032
	2	1973	2032
Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040

(a) Denotes year in which nuclear unit began commercial operations.

(b) Although timing has been delayed, Generation currently plans to seek license renewal for Clinton and has notified the NRC that any license renewal application would not be filed until the first quarter of 2024. In 2019, the NRC approved a change of the operating license expiration for Clinton from 2026 to 2027.

The operating license renewal process takes approximately four to five years from the commencement of the renewal process, which includes approximately two years for Generation to develop the application and approximately two years for the NRC to review the application. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the first renewal of the operating licenses for all of Generation's operating nuclear generating stations except for Clinton, Peach Bottom, Byron, and Dresden. Clinton depreciation provisions are based on an estimated useful life of 2027 which is the last year of the Illinois ZECs. Peach Bottom depreciation provisions are based on estimated useful life of 2053 and 2054 for Unit 2 and Unit 3, respectively, which reflects the second renewal of its operating licenses. Byron and Dresden depreciation provisions are based on the announced shutdown dates of September 2021 and November 2021, respectively.

Nuclear Waste Storage and Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the U.S., nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities on-site in storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2020, Generation had approximately 87,100 SNF assemblies (21,600 tons) stored on site in SNF pools or dry cask storage, which includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party, and TMI, which is no longer operational. See "— Decommissioning" below for additional information regarding Zion Station. All currently operating Generation-owned nuclear sites have on-site dry cask storage. TMI's on-site dry cask storage is projected to be in operation in 2021. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods and through decommissioning.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational for the next ten years.

Generation ships its Class A LLRW, which represents 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina, which have enough storage capacity to store all Class A LLRW for the life of all stations in Generation's nuclear fleet. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Salem) and Connecticut.

Generation utilizes on-site storage capacity at all its stations to store and stage for shipping Class B and Class C LLRW. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at each station as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation's nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and Class C LLRW for the life of all stations in Generation's nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize on-site storage and cost impacts.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with major incidents at all of its nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions.

Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Generation's and our future financial statements.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. The ultimate decommissioning obligation is expected to be funded by the NDT funds.

Oyster Creek Decommissioning. On July 1, 2019, Generation completed the sale with Holtec and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC (OCEP), of Oyster Creek nuclear generating station under which OCEP has assumed the responsibility for decommissioning that station.

Zion Station Decommissioning. On September 1, 2010, Generation completed an ASA with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion nuclear generating station.

Fossil and Renewable Facilities (including Hydroelectric)

We wholly own all of our fossil and renewable generating stations, with the exception of: Wyman; certain wind project entities and a biomass project entity with minority interest owners; and EGRP, which is owned 49% by another owner. Our fossil and renewable generating stations are all operated by us, with the exception of Wyman, which is operated by a third party. In 2020, 2019 and 2018, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 9%, 11% and 11%, respectively, of our total electric supply. The majority of this output was dispatched to support our wholesale and retail power marketing activities. On March 31, 2021, we closed an agreement to sell a significant portion of our solar business.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid, which include Conowingo Hydroelectric Project (Conowingo) and Muddy Run Pumped Storage Facility Project (Muddy Run). Muddy Run's license expires on December 1, 2055. On March 19, 2021, Generation received a new 50-year license for Conowingo.

Insurance. We maintain business interruption insurance for our renewable projects, but not for our fossil and hydroelectric operations unless required by contract or financing agreements. We maintain both property damage and liability insurance. For property damage and liability claims for these operations, we are self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on our future financial conditions and their results of operations and cash flows.

Contracted Generation

In addition to energy produced by owned generation assets, we source electricity from plants we do not own under long-term contracts. The following tables summarize our long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2020:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	8	2021 – 2032	183
Midwest	3	2021 – 2032	351
ERCOT	5	2021 – 2035	864
Other Power Regions	17	2021 – 2032	2,568
Total	33		3,966

	2021	2022	2023	2024	2025	Thereafter	Total
Capacity Expiring (MW)	884	304	103	101	461	2,113	3,966

The following table shows sources of electric supply in GWh for 2020 and 2019:

	Source of Electric Supply	
	2020	2019
Nuclear[(a)]	175,085	181,326
Purchases – non-trading portfolio	79,972	70,939
Fossil (primarily natural gas and oil)	19,501	21,554
Renewable[(b)]	7,052	7,777
Total supply	281,610	281,596

(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.

(b) Includes wind, hydroelectric, solar, and biomass generating assets.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride, and the fabrication of fuel assemblies. Generation has inventory in various forms and does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment, or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

We use financial instruments to mitigate price risk associated with certain commodity price exposures, using both over-the-counter and exchange-traded instruments.

Customers, Marketing and Price Risk Management

Constellation sells electricity and natural gas, including renewable energy and associated attributes, in competitive domestic energy markets to both wholesale and retail customers. We leverage our generation portfolio to serve customers under both long-term and short-term contracts, as well as spot market sales. We also have the capability to contract for generation to meet customer and portfolio needs to complement our existing fleet in a capital light, de-risked way.

Power Marketing

Our integrated business operations include physical delivery and marketing of power and natural gas. We largely obtain physical power supply from our owned and contracted generation in multiple geographic regions. The commodity risks associated with the output from owned and contracted generation is managed using various commodity transactions including sales to customers and our ratable hedging program. The main objective is to obtain low-cost energy supply to meet physical delivery obligations to both wholesale and retail customers. We sell electricity, natural gas, and other energy related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental and residential customers in competitive markets.

Price and Supply Risk Management

Constellation uses a combination of wholesale and retail customer load sales, as well as 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 the price risk of the generation portfolio. The portfolio has enjoyed more than a decade of a risk-mitigated ratable hedging strategy, whereby the prompt 3 years are hedged on an approximate rolling 90%/60%/30% basis, providing cash flow stability for its investors while still allowing commercial opportunities to generate value for the enterprise. Constellation will continue to be proactive in using hedging strategies to mitigate commodity price. Similarly, the scale and scope of the portfolio provides risk-mitigating technology, product and geographic diversification.

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 generation 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 wholesale and retail load sales, as well as hedging products, which include economic hedges and certain non-derivative contracts. A portion of our hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices. The risk management group monitors the financial risks of the wholesale and retail power marketing activities. We also use financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of our efforts. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits.

Seasonality

Our operations are affected by weather, which affects demand for electricity and natural gas, as well as operating conditions. The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. 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 those weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. As a result, our operating results in the future may fluctuate substantially on a seasonal basis, especially when more severe weather conditions such as heat waves or extreme winter weather make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities owned, the retail load served and the terms of contracts to purchase or sell electricity.

Properties and Facilities

The following table presents Generation's interests in net electric generating capacity by station at December 31, 2020:

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]
Midwest						
Braidwood	Braidwood, IL	2		Uranium	Base-load	2,386
Byron	Byron, IL	2		Uranium	Base-load	2,347[(e)]
LaSalle	Seneca, IL	2		Uranium	Base-load	2,320
Dresden	Morris, IL	2		Uranium	Base-load	1,845[(e)]
Quad Cities	Cordova, IL	2	75	Uranium	Base-load	1,403[(f)]
Clinton	Clinton, IL	1		Uranium	Base-load	1,080
Michigan Wind 2	Sanilac Co., MI	50	51[(g)]	Wind	Intermittent	46[(f)]
Beebe	Gratiot Co., MI	34	51[(g)]	Wind	Intermittent	42[(f)]
Michigan Wind 1	Huron Co., MI	46	51[(g)]	Wind	Intermittent	35[(f)]
Harvest 2	Huron Co., MI	33	51[(g)]	Wind	Intermittent	30[(f)]
Harvest	Huron Co., MI	32	51[(g)]	Wind	Intermittent	27[(f)]
Beebe 1B	Gratiot Co., MI	21	51[(g)]	Wind	Intermittent	26[(f)]
City Solar	Chicago, IL	1		Solar	Intermittent	9
Solar Ohio	Toledo, OH	2		Solar	Intermittent	4[(h)]
Blue Breezes	Faribault Co., MN	2		Wind	Intermittent	3
CP Windfarm	Faribault Co., MN	2	51[(g)]	Wind	Intermittent	2[(f)]
Southeast Chicago	Chicago, IL	8		Gas	Peaking	296[(i)]
Clinton Battery Storage	Blanchester, OH	1		Energy Storage	Peaking	10
Total Midwest						11,911

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]
Mid-Atlantic						
Limerick	Sanatoga, PA	2		Uranium	Base-load	2,317
Peach Bottom	Delta, PA	2	50	Uranium	Base-load	1,324[(f)]
Salem	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	995[(f)]
Calvert Cliffs	Lusby, MD	2	50.01[(j)]	Uranium	Base-load	895[(f)]
Conowingo	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Oakland, MD	28	51[(g)]	Wind	Intermittent	36[(f)]
Fair Wind	Garrett County, MD	12		Wind	Intermittent	30
Solar MC	Various, MD	44		Solar	Intermittent	44[(h)]
Fourmile Ridge	Garrett County, MD	16	51[(g)]	Wind	Intermittent	20[(f)]
Solar New Jersey 1	Various, NJ	5		Solar	Intermittent	18[(h)]
Solar New Jersey 2	Various, NJ	2		Solar	Intermittent	11[(h)]
Solar Horizons	Emmitsburg, MD	1	51[(g)]	Solar	Intermittent	16[(f)]
Solar Maryland	Various, MD	11		Solar	Intermittent	8[(h)]

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]
Solar Maryland 2	Various, MD	3		Solar	Intermittent	8[(h)]
JBAB Solar	District of Columbia	4		Solar	Intermittent	7[(h)]
Gateway Solar	Berlin, MD	1		Solar	Intermittent	7[(h)]
Constellation New Energy	Gaithersburg, MD	2		Solar	Intermittent	6[(h)]
Solar Federal	Trenton, NJ	1		Solar	Intermittent	5[(h)]
Solar New Jersey 3	Middle Township, NJ	5	51[(g)]	Solar	Intermittent	2[(f)]
Solar DC	District of Columbia	1		Solar	Intermittent	1[(h)]
Muddy Run	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Eddystone, PA	2		Oil/Gas	Peaking	760
Perryman	Aberdeen, MD	5		Oil/Gas	Peaking	404
Croydon	West Bristol, PA	8		Oil	Peaking	391
Handsome Lake	Kennerdell, PA	5		Gas	Peaking	268
Richmond	Philadelphia, PA	2		Oil	Peaking	98
Philadelphia Road	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Eddystone, PA	4		Oil	Peaking	60
Delaware	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Philadelphia, PA	4		Oil	Peaking	52
Falls	Morrisville, PA	3		Oil	Peaking	51
Moser	Lower Pottsgrove Twp., PA	3		Oil	Peaking	51
Chester	Chester, PA	3		Oil	Peaking	39
Schuylkill	Philadelphia, PA	2		Oil	Peaking	30
Salem	Lower Alloways Creek Township, NJ	1	42.59	Oil	Peaking	16[(f)]
Total Mid-Atlantic						9,729

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)(d)
ERCOT						
Whitetail	Webb County, TX	57	51[(g)]	Wind	Intermittent	47[(f)]
Sendero	Jim Hogg and Zapata County, TX	39	51[(g)]	Wind	Intermittent	40[(f)]
Constellation Solar Texas	Various, TX	11		Solar	Intermittent	13[(h)]
Colorado Bend II	Wharton, TX	3		Gas	Intermediate	1,143
Wolf Hollow II	Granbury, TX	3		Gas	Intermediate	1,115
Handley 3	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	Fort Worth, TX	2		Gas	Peaking	870
Total ERCOT						3,623

Station(a)	Location	No. of Units	Percent Owned(b)	Primary Fuel Type	Primary Dispatch Type(c)	Net Generation Capacity (MW)(d)
New York						
Nine Mile Point	Scriba, NY	2	50.01(j)	Uranium	Base-load	838(f)
FitzPatrick	Scriba, NY	1		Uranium	Base-load	842
Ginna	Ontario, NY	1	50.01(j)	Uranium	Base-load	288(f)
Solar New York	Bethlehem, NY	1		Solar	Intermittent	3(h)
Total New York						1,971

Station(a)	Location	No. of Units	Percent Owned(b)	Primary Fuel Type	Primary Dispatch Type(c)	Net Generation Capacity (MW)(d)
Other						
Antelope Valley	Lancaster, CA	1		Solar	Intermittent	242
Bluestem	Beaver County, OK	60	51(g)(k)	Wind	Intermittent	101(f)
Shooting Star	Kiowa County, KS	65	51(g)	Wind	Intermittent	53(f)
Albany Green Energy	Albany, GA	1	99(l)	Biomass	Base-load	50(f)(m)
Solar Arizona	Various, AZ	127		Solar	Intermittent	46(h)
Bluegrass Ridge	King City, MO	27	51(g)	Wind	Intermittent	29(f)
California PV Energy 2	Various, CA	89		Solar	Intermittent	27(h)
Conception	Barnard, MO	24	51(g)	Wind	Intermittent	26(f)
Cow Branch	Rock Port, MO	24	51(g)	Wind	Intermittent	26(f)
Solar Arizona 2	Various, AZ	56		Solar	Intermittent	34(h)
California PV Energy	Various, CA	53		Solar	Intermittent	21(h)
Mountain Home	Glenns Ferry, ID	20	51(g)	Wind	Intermittent	21(f)
High Mesa	Elmore Co., ID	19	51(g)	Wind	Intermittent	20(f)
Echo 1	Echo, OR	21	50.49(g)	Wind	Intermittent	17(f)
Sacramento PV Energy	Sacramento, CA	4	51(g)	Solar	Intermittent	30(f)
Cassia	Buhl, ID	14	51(g)	Wind	Intermittent	15(f)
Wildcat	Lovington, NM	13	51(g)	Wind	Intermittent	14(f)
Echo 2	Echo, OR	10	51(g)	Wind	Intermittent	10(f)
Solar Georgia 2	Various, GA	8		Solar	Intermittent	10(h)
Tuana Springs	Hagerman, ID	8	51(g)	Wind	Intermittent	9(f)
Solar Georgia	Various, GA	10		Solar	Intermittent	8(h)
Greensburg	Greensburg, KS	10	51(g)	Wind	Intermittent	6(f)
Solar Massachusetts	Various, MA	10		Solar	Intermittent	7(h)
Outback Solar	Christmas Valley, OR	1		Solar	Intermittent	6(h)
Echo 3	Echo, OR	6	50.49(g)	Wind	Intermittent	5(f)
Holyoke Solar	Various, MA	2		Solar	Intermittent	5(h)
Three Mile Canyon	Boardman, OR	6	51(g)	Wind	Intermittent	5(f)
Loess Hills	Rock Port, MO	4		Wind	Intermittent	5
California PV Energy 3	Various, CA	31		Solar	Intermittent	8(h)
Denver Airport Solar	Denver, CO	1	51(g)	Solar	Intermittent	4(f)
Solar Net Metering	Uxbridge, MA	1		Solar	Intermittent	2(h)
Solar Connecticut	Various, CT	1		Solar	Intermittent	1(h)

Station[a]	Location	No. of Units	Percent Owned[b]	Primary Fuel Type	Primary Dispatch Type[c]	Net Generation Capacity (MW)[d]
Mystic 8, 9	Charlestown, MA	6		Gas	Intermediate	1,413[e]
Hillabee	Alexander City, AL	3		Gas	Intermediate	753
Mystic 7	Charlestown, MA	1		Oil/Gas	Intermediate	512[n]
Wyman 4	Yarmouth, ME	1	5.9	Oil	Intermediate	35[f]
Grand Prairie	Alberta, Canada	1		Gas	Peaking	105
West Medway	West Medway, MA	3		Oil	Peaking	124
West Medway II	West Medway, MA	2		Oil/Gas	Peaking	192
Framingham	Framingham, MA	3		Oil	Peaking	31
Mystic Jet	Charlestown, MA	1		Oil	Peaking	9[n]
Total Other						4,037
Total						31,271

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, and Salem, which are pressurized water reactors.

(b) 100%, unless otherwise indicated.

(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermittent units are plants with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.

(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations and wind and solar facilities reflect a summer rating.

(e) On August 9, 2020, Generation announced it would permanently cease generation operations at Byron and Dresden nuclear facilities in 2021 and Mystic Unit 8 and 9 in 2024. On September 15, 2021, Generation reversed its previous decision to retire Byron and Dresden. See Note 7 — Early Plant Retirements of the Notes to Interim Consolidated Financial Statements and Note 7 — Early Plant Retirements of the Notes to Audited Consolidated Financial Statements for additional information.

(f) Net generation capacity is stated at proportionate ownership share.

(g) Reflects the prior sale of 49% of EGRP to a third party. See Note 21 — Variable Interest Entities of the Notes to Audited Consolidated Financial Statements for additional information.

(h) On December 8, 2020, Generation entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of Generation’s solar business. The transaction was completed on March 31, 2021. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Interim Consolidated Financial Statements for additional information.

(i) Generation has deactivated the site and is evaluating for potential return of service or retirement beyond 2021.

(j) Reflects Generation’s interest in CENG, a joint venture with EDF, as of December 31, 2020. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation, through a wholly owned subsidiary, purchased EDF’s equity interest in CENG. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Interim Consolidated Financial Statements for additional information.

(k) EGRP owns 100% of the Class A membership interests and a tax equity investor owns 100% of the Class B membership interests of the entity that owns the Bluestem generating assets.

(l) Generation directly owns a 50% interest in the Albany Green Energy station and an additional 49% through the consolidation of a Variable Interest Entity.

(m) On April 28, 2021, Constellation Holdings, LLC, a subsidiary of Generation, entered into a purchase agreement to sell Generation's interest in the Albany Green Energy biomass. The transaction was completed on June 30, 2021. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Interim Consolidated Financial Statements for additional information.

(n) Generation has plans to retire and cease plant operations in 2021.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies, or generating units being temporarily out of service for inspection, maintenance, refueling, repairs, or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements. Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect in Generation's consolidated financial condition or results of operations.

Employees

At the time of the separation, we expect to have approximately 12,500 employees, of which 12,478 are full-time.

As of December 31, 2020, approximately 3,418 employees are covered by 22 collective bargaining agreements. The terms of the collective bargaining agreements expire at various times and some may be subject to negotiations before the separation.

Engaged Workforce

We believe our employees are our greatest assets. We strive to create a workplace that is diverse, innovative, and safe for our employees. In order to provide the services and products that our customers expect, we must create the best teams. These teams must reflect the diversity of the communities that we serve. Therefore, we endeavor to attract highly qualified and diverse talent and routinely review hiring and promotion practices to ensure equitable and bias free processes are maintained to neutralize unconscious bias.

Exelon undertakes an extensive employee engagement survey every other year to help identify successes and opportunities for growth. In 2019, 81% of all Generation employees responded to the survey, and of those who responded, 78% indicated they were proud to work at Generation and 88% indicated they were proud of Generation's involvement in the community.

Career Development

We provide growth opportunities, competitive compensation and benefits, and a variety of training and development programs. We are committed to helping employees grow their skills and careers largely through training opportunities in technical, safety and business acumen areas, mentorship programs, and continuous feedback and development discussions and evaluations to develop a diverse talent pipeline for future jobs through training and mentoring programs. We understand that continued education leads to a more engaged, skilled and productive workforce and we support our employees in their educational endeavors in order to attract and retain people who are committed to personal and professional development by offering tuition reimbursement for approved higher education, certification or licensing courses.

Next Generation of Talent

We are also committed to exposing young people within our communities to career opportunities in the energy industry. Through internships, university and veteran recruiting, STEM programs, and partnerships with organizations such as the Society of Women Engineers and the National Society of Black Engineers, we are committed to providing professional development and opportunities for the next generation of our workforce. Major focus areas include:

- Creating the right STEM and vocational education and awareness among young people in our areas;
- Reducing or removing educational barriers and obstacles faced by young people and underrepresented and underserved members of the community; and
- Deepening current and executing new approaches and partnerships with employers, nonprofits, and community groups to expand training and job opportunities for work-ready adults and youth.

Well-Being and Benefits

Our employees are encouraged to thrive outside the workplace as well. We provide a full suite of wellness benefits targeted at supporting work-life balance, physical, mental, and financial health. In light of the COVID-19 pandemic, our employees also received the following additional benefits:

- 100% coverage of all in-network medical expenses associated with COVID-19 testing and treatment through June 2021;
- Paid time off to receive the COVID-19 vaccine; and
- Extended back-up child and elder care benefits through September 2020.

Community

We are also committed to helping improve the quality of life for people in the communities where we live, work and serve. We provide opportunities for company-sponsored volunteerism. Even in pandemic conditions, our employees donated over $5.1 million to non-profit organizations. Additionally, our employees provided nearly 50,000 hours of volunteering in 2020.

Turnover Rates. As turnover is inherent, management succession planning is performed and tracked for all executives and critical key manager positions. Management frequently reviews succession planning to ensure we are prepared when positions become available.

The table below shows the average turnover rate for all employees for the last three years of 2018 to 2020:

Retirement Age	4.80%
Voluntary	3.88%
Non-Voluntary	0.86%

Diversity Metrics. The following tables show diversity metrics for all employees and management as of December 31, 2020:

Employees	Generation
Female[(a)(b)]	2,492
People of Color[(b)]	2,083
Aged <30	1,363
Aged 30-50	6,712
Aged >50	4,407
Total Employees[(c)]	12,482

Management[(d)]	Generation
Female[(a)(b)]	299
People of Color[(b)]	220
Aged <30	51
Aged 30 – 50	1,220

Management[d]	Generation
Aged >50	841
Within 10 years of retirement eligibility	1,113
Total Employees in Management[c]	2,112

(a) We are devoted to creating an environment that allows women to stay in the workforce, grow with the company, and move up the ranks, all with parity of pay. We employ an independent third-party vendor to run regression analysis on all management positions each year. The analysis consistently shows that we have no systemic pay equity issues.

(b) This is based on self-disclosed information.

(c) Total employees represents the sum of the aged categories.

(d) Management is defined as executive/senior level officials and managers as well as all employees who have direct reports and supervisory responsibilities.

Environmental Matters

We are subject to comprehensive and complex environmental legislation and regulation at the federal, state, and local levels, including requirements relating to climate change, air and water quality, solid and hazardous waste, and impacts on species and habitats.

Our board of directors is responsible for overseeing the management of environmental matters. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process.

Climate Change Mitigation

We support comprehensive federal climate legislation that addresses the climate crisis and would ensure the country meets the targets set by the Paris Climate Accord. In the absence of comprehensive federal legislation, we support the EPA moving forward with meaningful regulation of GHG emissions under the Clean Air Act.

We are currently subject to, and may become subject to additional, federal and/or state legislation and/or regulations addressing GHG emissions. We produce electricity predominantly from low- and zero-carbon generating facilities (such as nuclear, hydroelectric, natural gas, wind, and solar PV) and neither own nor operate any coal-fueled generating assets. Our natural gas and biomass fired generating plants produce GHG emissions, most notably CO2. However, our owned-asset emission intensity, or rate of carbon dioxide equivalent (CO2e) emitted per unit of electricity generated, is among the lowest in the industry. In addition, we sell natural gas at retail; and consumers' use of such natural gas produces GHG emissions.

International Climate Change Agreements. At the international level, the United States is a party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. Under the Agreement, which became effective on November 4, 2016, the parties committed to try to limit the global average temperature increase and to develop national GHG reduction commitments. The Biden administration has announced a new target of 50-52 percent reduction in U.S. Greenhouse Gas Pollution from 2005 levels by 2030. In order to achieve this target and maintain high standards of reliability, the U.S. will need a reliable baseload of zero-carbon generating electricity sources, which our nuclear fleet helps provide.

Federal Climate Change Legislation and Regulation. It is highly uncertain whether federal legislation to significantly reduce GHG emissions will be enacted in the near-term. If such legislation were adopted, it would likely increase the value of our low-carbon fleet even though we may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. Continued inaction could negatively impact the value of our low-carbon fleet.

The Clean Power Plan and Affordable Clean Energy Rule. The EPA's 2015 Clean Power Plan (CPP) established regulations addressing carbon dioxide emissions from existing fossil-fired power plants under Clean Air Act Section 111(d). The CPP's carbon pollution limits could be met through changes to the electric generation system, including shifting generation from higher-emitting units to lower- or zero-emitting units, as well as the development of new or expanded zero-emissions generation. In July 2019, the EPA published its final Affordable Clean Energy rule, which repealed the CPP and replaced it with less stringent emissions guidelines for existing fossil-fired power plants based on heat rate improvement measures that could be achieved within the fence line of individual plants. Exelon, together with a coalition of other electric utilities, filed a lawsuit in the D.C. Circuit Court on September 6, 2019, challenging the Affordable Clean Energy rule as unlawful. This lawsuit was consolidated with separate challenges to the Affordable Clean Energy rule filed by various states, non-governmental organizations, and business coalitions. On January 19, 2021, the D.C. Circuit Court held the Affordable Clean Energy Rule to be unlawful, vacated the rule, and remanded it to the EPA. The EPA has indicated it will promulgate new GHG limits for existing power plants in accordance with the D.C. Circuit Court's order.

State Climate Change Legislation and Regulation. A number of states in which we operate have state and regional programs to reduce GHG emissions and renewable and other portfolio standards, which impact the power sector. See discussion below for additional information on renewable and other portfolio standards. As the nation's largest generator of carbon-free electricity, our fleet supports these efforts to produce safe, reliable electricity with minimal GHGs.

On September 15, 2021, Illinois Public Act 102-0662 was signed into law by the Governor of Illinois. The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. See "Overview of the U.S. Power Markets — Key Drivers — Policy Support for Nuclear Energy — Illinois Zero Emission Standard and Carbon Mitigation Credit Procurement" above for more information.

Eleven northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia) currently participate in the RGGI, which is in the process of strengthening its requirements. The program requires most fossil fuel-fired power plants in the region to hold allowances, purchased at auction, for each ton of CO2 emissions. Non-emitting resources do not have to purchase or hold these allowances. In October 2019, the Governor of Pennsylvania issued an Executive Order directing the PA DEP to begin a rulemaking process to allow Pennsylvania to join the RGGI, with the goal of reducing carbon emissions from the electricity sector. On November 7, 2020, the PA DEP proposed its rule.

Broader state programs impact other sectors as well, such as New York's Climate Leadership and Community Protection Act, which establishes statewide emission limits; and Massachusetts' Clean Energy and Climate Plan, which aims to reduce GHG emissions across all sectors through increased efficiency in buildings and vehicles, the electrification of vehicles and thermal conditioning in buildings, and the replacement of carbon intensive fuels with renewable energy sources.

While we cannot predict the nature of future regulations or how such regulations might impact future financial statements, we have a low emission portfolio, and GHG restrictions would likely benefit zero- and low-emission generating units relative to higher-emission fossil fuel-fired generating units.

In addition, our facilities and operations are subject to the global impacts of climate change. We believe our operations could be significantly affected by the physical risks of climate change. See "Risk Factors" beginning on page 26 of this information statement for additional information.

Renewable and Clean Energy Standards

Thirty states and the District of Columbia, incorporating the vast majority of states where we operate, have adopted some form of renewable or clean energy procurement requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. We own multiple facilities participating in these programs within states that have adopted standards targeted at preserving the zero-carbon attributes of certain nuclear-powered generating facilities, including Illinois, New York, and New Jersey. Other states in which we operate are considering similar programs. See Note 3 — Regulatory Matters of the Notes to Audited Consolidated Financial Statements for additional information.

Air Quality

Mercury and Air Toxics Standards (MATS). In 2011, the EPA signed a final rule, known as MATS, to reduce emissions of hazardous air pollutants from power plants. MATS requires coal-fired power 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. In 2016, in response to a Supreme Court decision requiring the EPA to consider costs in determining whether it was appropriate and necessary to regulate power plant emissions of hazardous air pollutants, the EPA issued a supplemental finding that, after considering costs, it remained appropriate and necessary. On May 22, 2020, the EPA reversed course, publishing a final rule revoking the “appropriate and necessary” finding underpinning MATS. A coal mining company filed a lawsuit in the D.C. Circuit Court seeking vacatur of MATS based on the EPA’s May 22, 2020 finding; on September 11, 2020, the D.C. Circuit Court granted a motion by Exelon and two other entities to intervene in that lawsuit to defend MATS, and on September 28, 2020, the D.C. Circuit Court issued an Executive Order holding this portion of the MATS litigation in abeyance. On July 21, 2020, Exelon and two other entities filed a lawsuit in the D.C. Circuit Court challenging the EPA’s May 22, 2020 rescission of the appropriate and necessary finding underpinning MATS. This portion of the case is also being held in abeyance in response to the DOJ’s motion filed February 12, 2021. On January 20, 2021, President Biden issued an Executive Order directing the EPA to reconsider its May 22, 2020 rescission by August 2021; the EPA is expected to re-affirm the finding that it is appropriate and necessary to regulate power plant emissions of hazardous air pollutants. As a result, this litigation is likely to be rendered moot, and MATS will likely remain in place in the interim.

Water Quality

Under the federal Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated, and permits must be renewed periodically. Certain of our facilities discharge stormwater, industrial wastewater, and/or cooling water into waterways and are therefore subject to these regulations and operate under NPDES permits.

Clean Water Act Section 316(b) is implemented through the NDPES program and requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. Our power generation facilities with cooling water intake systems are subject to the EPA’s Section 316(b) regulations finalized in 2014; the regulation’s requirements have been or will be addressed through renewal of these facilities’ NPDES permits. Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, we cannot estimate the effect that compliance with the EPA’s 2014 rule will have on the operation of its generating facilities and its financial statements. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility’s economic viability could be called into question. However, the final rule does not mandate cooling towers and allows state permitting directors to require alternative, less costly technologies and/or operational measures, based on a site-specific assessment of the feasibility, costs, and benefits of available options.

On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers and allows Salem to continue to operate utilizing the existing cooling water system with certain required system modifications. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

Under Clean Water Act Section 404 and state laws and regulations, we may be required to obtain permits for projects involving dredge or fill activities in Waters of the United States.

Where our facilities are required to secure a federal license or permit for activities that may result in a discharge to covered waters, we may be required to obtain a state water quality certification for those facilities under Clean Water Act section 401.

We are also subject to the jurisdiction of the Delaware River Basin Commission and the Susquehanna River Basin Commission, regional agencies that primarily regulate water usage.

Solid and Hazardous Waste and Environmental Remediation

CERCLA provides for response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of hazardous waste at sites, many of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight. Most states have also enacted statutes that contain provisions substantially similar to CERCLA. Such statutes apply in many states where we currently own or operate, or previously owned or operated, facilities, including Delaware, Illinois, Maryland, New Jersey, and Pennsylvania and the District of Columbia. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Our operations have in the past, and may in the future, require substantial expenditures in order to comply with these Federal and state environmental laws. Under these laws, we may be liable for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances generated by us. We own or lease a number of real estate parcels, including parcels on which our operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. We and our subsidiaries are, or could become in the future, parties to proceedings initiated by the EPA, state agencies, and/or other responsible parties under CERCLA and RCRA or similar state laws with respect to a number of sites or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

As of December 31, 2020, we have established appropriate contingent liabilities for environmental remediation requirements. In addition, we may be required to make significant additional expenditures not presently determinable for other environmental remediation costs. See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements for additional information regarding our environmental matters, remediation efforts, and related impacts to our Consolidated Financial Statements.

Legal Proceedings

We are parties to various lawsuits and regulatory proceedings in the ordinary course of our business. For information regarding material lawsuits and proceedings, see Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Company Overview

Our integrated business consists of the generation, physical delivery, and marketing of power across multiple geographical regions through our customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers and the production and sale of power through our competitive power generation business, Generation. We also sell renewable energy and other energy-related products and services. We have five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. For a more detailed description of the business, see "Summary" and "Our Business," which are included elsewhere within this information statement.

The Separation

On February 21, 2021, the Exelon Board authorized management to pursue a plan to separate its competitive generation and customer-facing businesses into a stand-alone publicly traded company, which we refer to as the separation in this information statement. The separation will occur through a distribution to Exelon's shareholders of all of the shares of common stock of the Company, which will own Generation, including its competitive generation, customer-facing power and gas supply, and related businesses. Following the distribution, Exelon shareholders will own 100% of the shares of our common stock. For a more detailed description of the separation, see "Summary" and "The Separation," which are included elsewhere within this information statement.

Significant 2020 and 2021 Transactions and Developments

COVID-19

We have taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of COVID-19. We provide a critical service to our customers which means that it is paramount that we keep our employees who operate our businesses safe and minimize unnecessary risk of exposure to the virus. We have taken extra precautions for our employees who work in the field and for employees who continue to work in our facilities. We have implemented work from home policies where appropriate, and imposed travel limitations on our employees. In addition, we have updated our existing business continuity plan in the context of this pandemic.

We continue to implement strong physical and cyber-security measures to ensure that our systems remain functional in order to both serve our operational needs with a remote workforce and keep them running to ensure uninterrupted service to our customers.

There were no changes in internal control over financial reporting in 2020 as a result of COVID-19 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Unfavorable economic conditions due to COVID-19 have impacted the demand for electricity and natural gas, which has resulted in a decrease in operating revenues.

As a result of COVID-19, we temporarily suspended interruption of service for all retail residential customers for non-payment and temporarily ceased new late payment fees for all retail customers from March to May of 2020. Such measures resulted in an increase in credit loss expense.

We have also incurred direct costs related to COVID-19 consisting primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of our employees. These costs are recorded as Operating and maintenance expense.

The estimated impact to our Net income was approximately $170 million for the year ended December 31, 2020 and is not expected to be material for the year ending December 31, 2021.

We rely on the capital markets for publicly offered debt as well as the commercial paper markets to meet our financial commitments and short-term liquidity needs. As a result of the disruptions in the commercial paper markets in March of 2020, we borrowed $1.5 billion on our revolving credit facility to refinance commercial paper, which we repaid on April 3, 2020. We also entered into two short-term loan agreements in March of 2020 for an aggregate of $500 million. On April 8, 2020, we received approximately $500 million in cash after entering into an accounts receivable financing arrangement. In addition, we issued long-term debt of $1.7 billion and were able to successfully complete our planned long-term debt issuances in 2020. See Liquidity and Capital Resources, Note 17 — Debt and Credit Agreements, and Note 6 — Accounts Receivable of the Notes to Audited Consolidated Financial Statements for additional information.

We assessed long-lived assets and investments for recoverability and there were no material impairment charges recorded in 2020 as a result of COVID-19. See Note 12 — Asset Impairments of the Notes to Audited Consolidated Financial Statements for additional information related to other impairment assessments in the third quarter of 2020. Certain assumptions are highly sensitive to changes. Changes in significant assumptions could potentially result in future impairments, which could be material.

This is an evolving situation that could lead to extended disruption of economic activity in our markets. We will continue to monitor developments affecting our workforce, customers, and suppliers and will take additional precautions that we determine to be necessary in order to mitigate the impacts. The extent to which COVID-19 may impact our ability to operate our generating assets, the ability to access capital markets, and results of operations, including demand for electricity and natural gas, will depend on the spread and proliferation of COVID-19 around the world and future developments, which are highly uncertain and cannot be predicted at this time.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions.

The estimated impact to our Net income for the nine months ended September 30, 2021 arising from these market and weather conditions was a reduction of approximately $880 million. We estimate a reduction in Net income of approximately $670 million to $820 million for the full year 2021. Our full year range is primarily based upon the estimated net loss for the nine months ended September 30, 2021 of approximately $800 million that has settled in cash. The nine months estimated Net income impact included a reduction of approximately $80 million due to estimated net penalties associated with the natural gas business, that we anticipate will be lowered in the fourth quarter 2021. Therefore, such charges are not included in the estimated full year earnings impact. Additionally, our full year range contemplates probabilities of outcomes on various pending legal and regulatory matters. The ultimate impact to our consolidated financial statements may be affected by a number of factors, including the impacts of customer and counterparty credit losses, any state or federal solutions to address the financial challenges caused by the event, and related litigation and contract disputes. See Note 3 — Regulatory Matters and Note 15 — Commitments and Contingencies of the Notes to Interim Consolidated Financial Statements for additional information.

We expect to offset between $370 million and $450 million of this impact for the full year 2021 through a combination of enhanced revenue opportunities, deferral of selected non-essential maintenance, and primarily one-time cost savings.

CENG Put Option

EDF had the option to sell us its 49.99% equity interest in CENG exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. On November 20, 2019, we received notice of EDF’s intention to exercise the put option and sell us its 49.99% equity interest in CENG and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period.

On August 6, 2021, we entered into a settlement agreement with EDF pursuant to which we, through a wholly owned subsidiary, purchased EDF’s equity interest in CENG for a net purchase price of $885 million, which includes, among other things, an adjustment for EDF's share of the balance of the preferred distribution payable to us by CENG. The difference between the net purchase price and EDF's noncontrolling interest as of the closing date was recorded to Membership interest in the Consolidated Balance Sheet.

In connection with the settlement agreement, on August 6, 2021, we issued approximately $880 million under a term loan credit agreement to fund the transaction, which will expire on August 5, 2022.

See Note 2 — Mergers, Acquisitions, and Dispositions and Note 13 — Debt and Credit Agreements of the Notes to Interim Consolidated Financial Statements for additional information.

Clean Energy Law

On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("*Clean Energy Law*"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorizes the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. The Byron, Dresden, and Braidwood nuclear plants located in Illinois were eligible to participate in the CMC procurement process and were awarded contracts to sell their respective CMCs in an amount equivalent to their full output to ComEd for a term of 5 years staring on June 1, 2022, committing them to operate through May 31, 2027.

Following enactment of the Clean Energy Law, we announced on September 15, 2021, that we have reversed our previous decision to retire Byron and Dresden given the opportunity for additional revenue. In addition, we no longer consider the Braidwood or LaSalle nuclear plants to be at risk for premature retirement. See Note 7 — Early Plant Retirements of the Notes to Interim Consolidated Financial Statements for additional information and Early Retirement of Facilities below.

Early Retirement of Facilities

In August 2020, we announced that we intended to retire the Byron Generating Station in September 2021, Dresden Generating Station in November 2021, and Mystic Units 8 and 9 at the expiration of the cost of service commitment in May 2024. As a result, we recognized certain one-time charges in the third and fourth quarters of 2020. Further, there were ongoing annual financial impacts stemming from shortening the expected economic useful lives of these facilities, primarily related to accelerated depreciation of plant assets (including any ARC) and accelerated amortization of nuclear fuel.

Also, as a result, in the third quarter of 2020, we recognized a $500 million pre-tax impairment for the New England asset group. In the second quarter of 2021, an incremental decline in value resulted in an additional pre-tax impairment charge of $350 million for the New England asset group.

Further, in the second quarter and third quarter of 2021, we recorded a pre-tax charge of $53 million and $140 million, respectively for decommissioning-related activities that were not offset for the Byron units due to the inability to recognize a regulatory asset at ComEd.

On September 15, 2021, we reversed our previous decision to early retire Byron and Dresden and updated the expected economic useful life for both facilities to 2044 and 2046 for Byron Units 1 and 2, respectively, and to 2029 and 2031 for Dresden Units 2 and 3, respectively. Depreciation was therefore adjusted beginning September 15, 2021, to reflect these extended useful life estimates. In addition, in the third quarter of 2021, we reversed approximately $81 million of severance benefit costs and $13 million of other one-time charges initially recorded in the third and fourth quarters of 2020 associated with the early retirements.

The following table summarizes the incremental expense for Byron, Dresden, and Mystic Units 8 and 9 and the reversal of one-time charges recorded in the nine months ended September 30, 2021. For Mystic Units 8 and 9, the projected amounts for the remainder of 2021 and through the retirement date of 2024 are not expected to be material.

Income statement expense (pre-tax) (in millions)	Nine Months Ended September 30, 2021
Depreciation and amortization	
Accelerated depreciation[a]	$1,845
Accelerated nuclear fuel amortization	148
Operating and maintenance	
Reversal of one-time charges	(94)
Other charges	8
Contractual offset[b]	(451)
Total	$1,456

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

(b) Reflects contractual offset for ARO accretion, ARC depreciation, and net impacts associated with the remeasurement of the ARO for Byron and Dresden and exclude any changes in earnings in the NDT funds. Decommissioning-related activities were not offset for the Byron units starting in the second quarter of 2021 due to the inability to recognize a regulatory asset at ComEd. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. Based on the regulatory agreement with the ICC, decommissioning-related activities are offset in the Consolidated Statements of Operations and Comprehensive Income as long as the net cumulative decommissioning-related activities result in a regulatory liability at ComEd. Recognition of a regulatory asset for nuclear decommissioning-related activities at ComEd is not permissible. The offset results in an equal adjustment to the noncurrent payables to ComEd.

See Note 7 — Early Plant Retirements, Note 8 — Nuclear Decommissioning, and Note 9 — Asset Impairments of the Notes to Interim Consolidated Financial Statements for additional information.

Agreement for Sale of our Solar Business

On December 8, 2020, we entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of our solar business, including 360 megawatts of generation in operation or under construction across more than 600 sites across the United States. We will retain certain solar assets not included in this agreement, primarily Antelope Valley.

Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions which were satisfied in the first quarter of 2021. The sale was completed on March 31, 2021 for a purchase price of $810 million. We received cash proceeds of $675 million, net of $125 million long term debt assumed by the buyer and certain working capital and other post-closing adjustments. We recognized a pre-tax gain of $68 million which is included in Gain on sales of assets and businesses in our Consolidated Statements of Operations and Comprehensive Income. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Interim Consolidated Financial Statements for additional information.

Agreement for the Sale of a Biomass Facility

On April 28, 2021, we entered into a purchase agreement with ReGenerate Energy Holdings, LLC (“ReGenerate”), under which ReGenerate agreed to purchase our interest in the Albany Green Energy biomass facility. As a result, in the second quarter of 2021, we recorded a pre-tax impairment charge of $140 million. The sale was completed on June 30, 2021 for a net purchase price of $36 million. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Interim Consolidated Financial Statements for additional information.

Sales of Customer Accounts Receivable

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly owned by us, entered into an accounts receivable financing facility with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivables (the Facility). We received approximately $500 million of cash in accordance with the initial sale of approximately $1.2 billion receivables. On February 17, 2021, we received additional cash of $250 million from the Purchasers for the remaining capacity in the Facility. The Facility was renewed on March 29, 2021. The Facility term was extended through March 29, 2024, unless further renewed by the mutual consent of the parties, and the maximum capacity was increased to $900 million. On March 31, 2021, we received cash of approximately $150 million in connection with the increased capacity at the time of the Facility renewal. See Note 6 — Accounts Receivable of the Notes to Interim Consolidated Financial Statements for additional information.

Other Key Business Drivers

Power Markets

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 from imports of uranium products, alleging that these imports threaten national security.

The United States Nuclear Fuel Working Group (“Working Group”) report was made public on April 23, 2020. The Working Group report states that nuclear power is intrinsically tied to national security, and promises that the U.S. government will take bold actions to strengthen all parts of the nuclear fuel industry in the U.S. It recommends the Agreement Suspending the Antidumping Investigation on Uranium from the Russian Federation (the “Russian Suspension Agreement” or “RSA”) be extended and to consider reducing the amount of Russian imports of nuclear fuel. The Russian Suspension Agreement is the historical resolution of a 1991 DOC investigation that found that the Russians had been selling or “dumping” cheap uranium products into the U.S. The RSA has been amended several times in the intervening years to allow Russia to supply limited amounts of uranium products into the U.S. It was set to expire at the end of 2020, but was amended on October 5, 2020 to extend for another 20 years.

The Working Group report should be viewed as policy recommendations that may be implemented by executive agencies, congress, and or regulatory bodies. We cannot currently predict the outcome of all of the policy changes recommended by the Working Group.

Complaint at FERC Seeking to Alter Capacity Market Default Offer Caps

On February 21, 2019, PJM’s Independent Market Monitor (IMM) filed a complaint alleging that the number of performance assessment intervals used to calculate the default offer cap for bids to supply capacity in PJM is too high, resulting in an overstated default offer cap that obviates the need for most sellers to seek unit-specific approval of their offers. The IMM argued that this allows for the exercise of market power. The IMM asked FERC to require PJM to reduce the number of performance assessment intervals used to calculate the opportunity costs of a capacity supplier assuming a capacity obligation. This would, in turn, lower the default offer cap and allow the IMM to review more offers on a unit-specific basis. Several consumer advocates filed a complaint seeking similar relief several months after the IMM’s complaint. On March 18, 2021, FERC granted the complaints, finding the current estimate of performance assessment intervals to be excessive compared to the reasonably expected number of performance assessment intervals which results in an unjust and unreasonable default offer cap. FERC did not establish the number of performance assessment intervals that should be used to calculate the default offer cap and instead requested briefs on the matter, including alternative approaches to mitigation in the capacity market. We submitted an initial and reply briefs on May 3, 2021 and June 9, 2021, respectively, and an answer to briefs filed by other parties on June 24, 2021. On September 2, 2021, FERC issued an order adopting the IMM’s unit-specific avoidable cost offer review methodology and directed PJM to submit a compliance filing establishing new deadlines for offer review and related other activities leading up to the base residual auction for the 2023-2024 planning year and an additional compliance filing revising the PJM Tariff to comply with FERC’s order. We filed at FERC for rehearing on this matter on October 4, 2021. We cannot predict the outcome of these proceedings or the financial statement impact.

Hedging Strategy

Our policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. We are exposed to commodity price risk associated with the unhedged portion of our electricity portfolio. We enter 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. As of September 30, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 96%-99% for the remainder of 2021. We have been and will continue to be proactive in using hedging strategies to mitigate commodity price risk.

We procure natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are 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 are subject to price fluctuations and availability restrictions. Approximately 60% of our uranium concentrate requirements from 2021 through 2025 are supplied by three suppliers. In the event of non-performance by these or other suppliers, we believe 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 our consolidated financial statements.

See Note 12 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements and “Quantitative and Qualitative Disclosures About Market Risk” for additional information.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management believes that the accounting policies described below require significant judgment in their application or incorporate estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional information of the application of these accounting policies can be found in the Notes to Audited Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations

Our ARO associated with decommissioning our nuclear units was $11.9 billion at December 31, 2020. The authoritative guidance requires that we estimate our obligation for the future decommissioning of our nuclear generating plants. To estimate that liability, we use an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning outcome scenarios.

As a result of recent nuclear plant retirements in the industry, nuclear operators and third-party service providers are obtaining more information about costs associated with decommissioning activities. At the same time, regulators are gaining more information about decommissioning activities which could result in changes to existing decommissioning requirements. In addition, as more nuclear plants are retired, it is possible that technological advances will be identified that could create efficiencies and lead to a reduction in decommissioning costs. The availability of NDT funds could impact the timing of the decommissioning activities. Additionally, certain factors such as changes in regulatory requirements during plant operations or the profitability of a nuclear plant could impact the timing of plant retirements. These factors could result in material changes to our current estimates as more information becomes available and could change the timing of plant retirements and the probability assigned to the decommissioning outcome scenarios.

The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing and/or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the following methodologies and significant estimates and assumptions:

Decommissioning Cost Studies. We use unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of our nuclear units at least every five years, unless circumstances warrant more frequent updates. As part of the annual cost study update process, we evaluate newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle.

Cost Escalation Factors. We use cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs. All of the nuclear AROs are adjusted each year for the updated cost escalation factors.

Probabilistic Cash Flow Models. Our probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning cost levels, decommissioning approaches, and timing of plant shutdown on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. The assumed decommissioning scenarios include the following three alternatives: (1) DECON which assumes decommissioning activities begin shortly after the cessation of operation, (2) Shortened SAFSTOR generally has a 30-year delay prior to onset of decommissioning activities, and (3) SAFSTOR which assumes the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated generally within 60 years after cessation of operations. In each decommissioning scenario, spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

The actual decommissioning approach selected once a nuclear facility is shutdown will be determined at the time of shutdown and may be influenced by multiple factors including the funding status of the nuclear decommissioning trust fund at the time of shutdown.

The assumed plant shutdown timing scenarios include the following four alternatives: (1) the probability of operating through the original 40-year nuclear license term, (2) the probability of operating through an extended 60-year nuclear license term (regardless of whether such 20-year license extension has been received for each unit), (3) the probability of a second, 20-year license renewal for some nuclear units, and (4) the probability of early plant retirement for certain sites due to changing market conditions and regulatory environments. As power market and regulatory environment developments occur, we evaluate and incorporate, as necessary, the impacts of such developments into its nuclear ARO assumptions and estimates.

Our probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. We currently assume DOE will begin accepting SNF in 2035. The SNF acceptance date assumption is based on management’s estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage. For additional information regarding the estimated date when DOE will begin accepting SNF, see Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements.

Discount Rates. The probability-weighted estimated future cash flows for the various assumed scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. We initially recognize an ARO at fair value and subsequently adjust it for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions. The ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. Increases in the ARO as a result of upward revisions in estimated undiscounted cash flows are considered new obligations and are measured using a current CARFR as the increase creates a new cost layer within the ARO. Any decrease in the estimated undiscounted future cash flows relating to the ARO are treated as a modification of an existing ARO cost layer and, therefore, is measured using the average historical CARFR rates used in creating the initial ARO cost layers. If our future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFR, the obligation would increase from approximately $11.9 billion to approximately $15.0 billion.

The following table illustrates the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO (dollars in millions):

Change in the CARFR applied to the annual ARO update (in millions)	(Decrease) Increase to ARO at December 31, 2020
2019 CARFR rather than the 2020 CARFR	$(370)
2020 CARFR increased by 50 basis points	(390)
2020 CARFR decreased by 50 basis points	490

ARO Sensitivities. Changes in the assumptions underlying the ARO could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions may correspondingly change.

The following table illustrates the effects of changing certain ARO assumptions while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption (in millions)	Increase to ARO at December 31, 2020
Cost escalation studies	
Uniform increase in escalation rates of 50 basis points	$2,560
Probabilistic cash flow models	
Increase the estimated costs to decommission the nuclear plants by 10 percent	1,050
Increase the likelihood of the DECON scenario by 10 percent and decrease the likelihood of the SAFSTOR scenario by 10 percent[a]	610
Shorten each unit’s probability weighted operating life assumption by 10 percent[b]	1,690
Extend the estimated date for DOE acceptance of SNF to 2040	280

(a) Excludes any sites in which management has committed to a specific decommissioning approach.

(b) Excludes any retired sites.

See Note 1 — Significant Accounting Policies, Note 7 — Early Plant Retirements, and Note 10 — Asset Retirement Obligations of the Notes to Audited Consolidated Financial Statements for additional information regarding accounting for nuclear AROs.

Unamortized Energy Contract Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that we have acquired. The initial amount recorded represents the fair value of the contracts at the time of acquisition. The unamortized energy contract assets and liabilities are amortized over the life of the contract in relation to the expected realization of the underlying cash flows. Amortization of the unamortized energy contract assets and liabilities is recorded through purchased power and fuel expense or operating revenues, depending on the nature of the underlying contract. See Note 13 — Intangible Assets of the Notes to Audited Consolidated Financial Statements for additional information.

Impairment of Long-Lived Assets

We regularly monitor and evaluate the carrying value of long-lived assets and asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of potential impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, an asset remaining idle for more than a short period of time, specific regulatory disallowance, advances in technology, plans to dispose of a long-lived asset significantly before the end of its useful life, and financial distress of a third party for assets contracted with them on a long-term basis, among others.

The review of long-lived assets and asset groups for impairment utilizes significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. Forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power and purchases of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could potentially result in material future impairments. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. The lowest level of independent cash flows is determined by the evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units as well as the associated intangible assets or liabilities recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generating assets (typically contracted renewables). For such assets the financial viability of the third party, including the impact of bankruptcy on the contract, may be a significant assumption in the assessment.

On a quarterly basis, we assess our long-lived assets or asset groups for indicators of impairment. If indicators are present for a long-lived asset or asset group, a comparison of the undiscounted expected future cash flows to the carrying value is performed. When the undiscounted cash flow analysis indicates the carrying value of a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value of the long-lived asset or asset group is dependent upon a market participant’s view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances often do not occur as expected resulting in differences between prospective financial information and actual results, which may be material. The determination of fair value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources.

See Note 12 — Asset Impairments of the Notes to Audited Consolidated Financial Statements for a discussion of asset impairment assessments.

Depreciable Lives of Property, Plant and Equipment

We have significant investments in electric generation assets. These assets are generally depreciated on a straight-line basis, using the group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for heterogeneous assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are generally completed every five years, or more frequently if an event, regulatory action, or change in retirement patterns indicate an update is necessary.

Along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of our generating facilities and reassesses the reasonableness of estimated useful lives whenever events or changes in circumstances warrant. When a determination has been made that an asset will be retired before the end of its current estimated useful life, depreciation provisions will be accelerated to reflect the shortened estimated useful life, which could have a material unfavorable impact on future results of operations. See Note 7 — Early Plant Retirements of the Notes to Audited Consolidated Financial Statements for additional information.

Changes in estimated useful lives of electric generation assets could have a significant impact on the future results of operations. See Note 1 — Significant Accounting Policies of the Notes to Audited Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment.

Accounting for Derivative Instruments

We use derivative instruments to manage commodity price risk, foreign currency exchange risk and interest rate risk related to ongoing business operations. Our derivative activities are in accordance with our Risk Management Policy (RMP). See Note 16 — Derivative Financial Instruments of the Notes to Audited Consolidated Financial Statements for additional information.

We account for derivative financial instruments under the applicable authoritative guidance. Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing market liquidity as well as determining whether a contract has one or more underlyings and one or more notional quantities. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance, could result in previously excluded contracts becoming in scope of new authoritative guidance.

All derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, NPNS. Derivatives entered into for economic hedging and for proprietary trading purposes are recorded at fair value through earnings.

NPNS. As part of our energy marketing business, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as NPNS transactions, which are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the NPNS requires judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as NPNS are recognized when the underlying physical transaction is completed. Contracts that qualify for the NPNS are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and the contract is not financially settled on a net basis.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires us to determine that the contract is in accordance with the RMP. We reassess our economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of the authoritative guidance, we make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. Under the authoritative guidance for fair value measurements, we categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value.

Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are generally categorized in Level 1 in the fair value hierarchy.

Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges. The price quotations reflect the average of the bid-ask mid-point from markets that we believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. Our derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using models that consider inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2.

For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs and are categorized in Level 3.

We consider nonperformance risk, including credit risk in the valuation of derivative contracts, including both historical and current market data, in our assessment of nonperformance risk, including credit risk. The impacts of nonperformance and credit risk to date have generally not been material to the financial statements.

See “Quantitative and Qualitative Disclosures About Market Risk” and Note 18 — Fair Value of Financial Assets and Liabilities and Note 16 — Derivative Financial Instruments of the Notes to Audited Consolidated Financial Statements for additional information regarding derivative instruments.

Taxation

Significant management judgment is required in determining our provision for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. We account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the consolidated financial statements.

We evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. We also assess negative evidence, such as the expiration of historical operating loss or tax credit carryforwards, that could indicate our inability to realize our deferred tax assets. Based on the combined assessment, we record valuation allowances for deferred tax assets when it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including future changes in income tax laws, our forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. See Note 14 — Income Taxes of the Notes to Audited Consolidated Financial Statements for additional information.

Accounting for Loss Contingencies

In the preparation of our financial statements, we make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amount recorded may differ from the actual expense incurred when the uncertainty is resolved. Such difference could have a significant impact in our consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which we will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work and changes in technology, regulations and the requirements of local governmental authorities. In addition, periodic reviews are performed to assess the adequacy of other environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant impact in the consolidated financial statements. See Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements for additional information.

Other, Including Personal Injury Claims. We are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. We have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material impact in the consolidated financial statements.

Revenue Recognition

Sources of Revenue and Determination of Accounting Treatment. We earn revenue 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) 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. We primarily apply the Revenue from Contracts with Customers and Derivatives guidance to recognize revenue as discussed in more detail below.

Revenue from Contracts with Customers. We 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 and services are provided to the customer. Transactions within the scope of Revenue from Contracts with Customers generally include non-derivative agreements, contracts that are designated as NPNS and spot-market energy commodity sales, including settlements with independent system operators.

The determination of our retail power and natural gas sales to individual customers is based on systematic readings of customer meters, generally on a monthly basis. Energy delivered to customers that has not yet been billed as of the reporting period is estimated and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is based upon individual customer meter readings, forecasted volumes, and applicable rates. See Note 1 — Significant Accounting Policies of the Notes to Audited Consolidated Financial Statements for additional information.

Derivative Revenues. We 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.

Factors Affecting the Comparability of our Future Results of Operations to our Historical Results of Operations

The historical audited financial information we have included in this information statement does not necessarily reflect what our financial condition, results of operations or cash flows would have been as an independent public company during the periods presented and is not necessarily indicative of our future financial condition, future results of operations or future cash flows. This is primarily a result of the following factors:

- The historical audited financial results reflect allocations of expenses for services historically provided by BSC, and those allocations may be different than the comparable expenses we would have incurred as an independent company,
- Our cost of debt and other capitalization may be different from that reflected in our historical audited financial statements,

- The historical audited financial information does not reflect the changes that will occur in our cost structure, management, financing arrangements and business operations as a result of our separation from Exelon, including the costs related to being an independent company, and
- Other significant changes may occur in our cost structure, management, financing and business operations as a result of our operation as a company separate from Exelon.

Results of Operations

Nine Months Ended September 30, 2021 Compared to the Nine Months Ended September 30, 2020

(in millions)	Nine Months Ended September 30, 2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$14,117	$13,272	$ 845
Operating expenses			
Purchased power and fuel	8,103	6,961	(1,142)
Operating and maintenance	3,413	4,188	775
Depreciation and amortization	2,735	1,161	(1,574)
Taxes other than income taxes	354	364	10
Total operating expenses	14,605	12,674	(1,931)
Gain on sales of assets and businesses	144	12	132
Operating (loss) income	(344)	610	(954)
Other income and (deductions)			
Interest expense, net	(225)	(277)	52
Other, net	561	199	362
Total other income and (deductions)	336	(78)	414
(Loss) income before income taxes	(8)	532	(540)
Income taxes	108	41	(67)
Equity in losses of unconsolidated affiliates	(6)	(6)	—
Net (loss) income	(122)	485	(607)
Net income (loss) attributable to noncontrolling interests	125	(85)	210
Net (loss) income attributable to membership interest	$ (247)	$ 570	$ (817)

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. Net income attributable to membership interest decreased by $817 million primarily due to:

- Impacts of the February 2021 extreme cold weather event;
- Accelerated depreciation and amortization associated with our previous decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021, a decision which was reversed on September 15, 2021, and our decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024;
- Decommissioning-related activities that were not offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date;
- Impairments of the New England asset group, the Albany Green Energy biomass facility, and a wind project, partially offset by the absence of an impairment of the New England asset group in the third quarter of 2020; and
- The absence of a prior year one-time tax settlement.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Higher net unrealized and realized gains on NDT funds;
- Absence of one time charges recorded in the third quarter of 2020 associated with our decision to early retire the Byron and Dresden nuclear facilities and Mystic Units 8 and 9, and the reversal of one-time charges resulting from the reversal of the previous decision to early retire Byron and Dresden on September 15, 2021;
- Lower nuclear outage days; and
- Higher New York ZEC revenues due to higher generation and an increase in ZEC prices.

Operating revenues. The basis for our reportable segments is the integrated management of our 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). Our hedging strategies and risk metrics are also aligned with these same geographic regions. Our five reportable segments are Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 5 — Segment Information of the Notes to Interim Consolidated Financial Statements for additional information on these reportable segments.

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 overall operating revenues or results of operations.

For the nine months ended September 30, 2021 compared to 2020, Operating revenues by region were as follows:

	Nine Months Ended September 30,			
(in millions)	**2021**	**2020**	**Variance**	**% Change[(a)]**
Mid-Atlantic	$ 3,527	$ 3,561	$ (34)	(1.0)%
Midwest	2,945	3,007	(62)	(2.1)%
New York	1,173	1,061	112	10.6%
ERCOT	890	754	136	18.0%
Other Power Regions	3,729	2,984	745	25.0%
Total electric revenues	12,264	11,367	897	7.9%
Other	2,811	1,667	1,144	68.6%
Mark-to-market (losses) gains	(958)	238	(1,196)	
Total Operating revenues	$14,117	$13,272	$ 845	6.4%

(a) % Change in mark-to-market is not a meaningful measure.

Supply Sources. Our supply sources by region are summarized below:

Supply Source (GWhs)	Nine Months Ended September 30, 2021	2020	Variance	% Change
Nuclear Generation[a]				
Mid-Atlantic	40,203	39,630	573	1.4%
Midwest	70,363	71,929	(1,566)	(2.2)%
New York	21,323	19,296	2,027	10.5%
Total Nuclear Generation	131,889	130,855	1,034	0.8%
Fossil and Renewables				
Mid-Atlantic	1,675	1,864	(189)	(10.1)%
Midwest	763	852	(89)	(10.4)%
New York	1	3	(2)	(66.7)%
ERCOT	10,250	10,658	(408)	(3.8)%
Other Power Regions	7,641	8,905	(1,264)	(14.2)%
Total Fossil and Renewables	20,330	22,282	(1,952)	(8.8)%
Purchased Power				
Mid-Atlantic	12,123	17,924	(5,801)	(32.4)%
Midwest	386	595	(209)	(35.1)%
ERCOT	2,626	3,351	(725)	(21.6)%
Other Power Regions	38,778	37,981	797	2.1%
Total Purchased Power	53,913	59,851	(5,938)	(9.9)%
Total Supply/Sales by Region				
Mid-Atlantic	54,001	59,418	(5,417)	(9.1)%
Midwest	71,512	73,376	(1,864)	(2.5)%
New York	21,324	19,299	2,025	10.5%
ERCOT	12,876	14,009	(1,133)	(8.1)%
Other Power Regions	46,419	46,886	(467)	(1.0)%
Total Supply/Sales by Region	206,132	212,988	(6,856)	(3.2)%

(a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants. Includes the total output for fully owned plants and the total output for CENG prior to the acquisition of EDF's interest on August 6, 2021 as CENG was fully consolidated. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Interim Consolidated Financial Statements for additional information on our acquisition of EDF's interest in CENG.

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for our plants, which reflects ownership percentage of stations operated by us, excluding Salem, which is operated by PSEG. 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. We consider capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. We have 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.

	Nine Months Ended September 30,	
	2021	2020
Nuclear fleet capacity factor	95.0%	95.1%
Refueling outage days	172	203
Non-refueling outage days	10	15

ZEC Prices. We are compensated through state programs for the carbon-free attributes of our nuclear generation. ZEC prices have a significant impact on Operating revenues. The following table presents the average ZEC prices ($/MWh) for each of our major regions in which state programs have been enacted. Prices reflect the weighted average price for the various delivery periods within each calendar year.

	Nine Months Ended September 30,			
State (Region)	2021	2020	Variance	% Change
New Jersey (Mid-Atlantic)	$10.00	$10.00	$ —	—%
Illinois (Midwest)	16.50	16.50	—	—%
New York (New York)	20.78	19.59	1.19	6.1%

Capacity Prices. We participate in capacity auctions in each of our major regions, except ERCOT which does not have a capacity market. We also incur capacity costs associated with load served, except in ERCOT. Capacity prices have a significant impact on our operating revenues and purchased power and fuel. The following table presents the average capacity prices ($/MW Day) for each of our major regions. Prices reflect the weighted average price for the various auction periods within each calendar year.

	Nine Months Ended September 30,			
Location (Region)	2021	2020	Variance	% Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic and Midwest)	$178.03	$159.50	$ 18.53	11.6%
ComEd (Midwest)	191.42	194.22	(2.80)	(1.4)%
Rest of State (New York)	94.12	54.32	39.80	73.3%
Southeast New England (Other)	166.76	200.69	(33.93)	(16.9)%

Electricity Prices. The price of electricity has a significant impact on our operating revenues and purchased power cost. The following table presents the average day-ahead around-the-clock price ($/MWh) for each of our major regions.

	Nine Months Ended September 30,			
Location (Region)	2021	2020	Variance	% Change
PJM West (Mid-Atlantic)	$ 33.70	$20.24	$ 13.46	66.5%
ComEd (Midwest)	31.76	18.57	13.19	71.0%
Central (New York)	26.58	16.33	10.25	62.8%
North (ERCOT)	182.23	21.83	160.40	734.8%
Southeast Massachusetts (Other)[(a)]	41.54	21.26	20.28	95.4%

(a) Reflects New England, which comprises the majority of the activity in the Other region.

For the nine months ended September 30, 2021 compared to 2020, changes in **Operating revenues** by region were approximately as follows:

(in millions)	Variance	% Change[(a)]	Nine Months Ended September 30, 2021
Mid-Atlantic	$ (34)	(1.0)%	• unfavorable wholesale load revenue of $(370) primarily due to lower volumes; partially offset by • favorable settled economic hedges of $305 due to settled prices relative to hedged prices • favorable retail load revenue of $35 primarily due to higher prices
Midwest	(62)	(2.1)%	• unfavorable settled economic hedges of $(375) due to settled prices relative to hedged prices; partially offset by • favorable net wholesale load and generation revenue of $315 primarily due to higher prices, partially offset by decreased generation due to higher nuclear outage days
New York	112	10.6%	• favorable nuclear generation revenue of $40 primarily due to lower outage days and higher prices • favorable ZEC revenue of $65 due to higher prices and higher nuclear generation
ERCOT	136	18.0%	• favorable retail load revenue of $120 primarily due to higher prices in part due to the February 2021 extreme cold weather event
Other Power Regions	745	25.0%	• favorable settled economic hedges of $520 due to settled prices relative to hedged prices • favorable retail load revenue of $400 due to higher prices and higher volumes; partially offset by • unfavorable wholesale load revenue of $(205) primarily due to lower volumes
Other	1,144	68.6%	• favorable gas revenue of $1,060 primarily due to higher prices in part due to the February 2021 extreme cold weather event
Mark-to-market[(b)]	(1,196)		• losses on economic hedging activities of $(958) in 2021 compared to gains of $238 in 2020
Total	$ 845	6.4%	

(a) % Change in mark-to-market is not a meaningful measure.

(b) See Note 12 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements for additional information on mark-to-market gains and losses.

Purchased power and fuel. See Operating revenues above for discussion of our reportable segments and hedging strategies and for supplemental statistical data, including supply sources by region, nuclear fleet capacity factor, capacity prices, and electricity prices.

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 overall purchased power and fuel expense or results of operations, and accelerated nuclear fuel amortization associated with nuclear decommissioning.

For the nine months ended September 30, 2021 compared to 2020, Purchased power and fuel by region were as follows:

(in millions)	Nine Months Ended September 30, 2021	2020	Variance	% Change[a]
Mid-Atlantic	$ 1,815	$1,878	$ 63	3.4%
Midwest	930	829	(101)	(12.2)%
New York	293	336	43	12.8%
ERCOT	1,812	429	(1,383)	(322.4)%
Other Power Regions	3,165	2,446	(719)	(29.4)%
Total electric purchased power and fuel	8,015	5,918	(2,097)	(35.4)%
Other	2,288	1,277	(1,011)	(79.2)%
Mark-to-market gains	(2,200)	(234)	1,966	
Total purchased power and fuel	$ 8,103	$6,961	$(1,142)	(16.4)%

(a) % Change in mark-to-market is not a meaningful measure.

For the nine months ended September 30, 2021 compared to 2020, changes in **Purchased power and fuel** by region were approximately as follows:

(in millions)	Variance	% Change[a]	Nine Months Ended September 30, 2021
Mid-Atlantic	$ 63	3.4%	• favorable purchased power and net capacity impact of $45 primarily due to lower load and higher capacity prices earned partially offset by lower cleared capacity volumes • favorable settlement of economic hedges of $40 due to settled prices relative to hedged prices
Midwest	(101)	(12.2)%	• unfavorable purchased power and net capacity impact of $(140) primarily due to lower nuclear generation due to higher nuclear outage days, higher energy prices, lower cleared capacity volumes, and lower capacity prices
New York	43	12.8%	• favorable settlement of economic hedges of $70 due to settled prices relative to hedged prices; partially offset by • unfavorable purchased power and net of capacity impact of $(35) primarily due to higher energy prices partially offset by higher capacity prices earned
ERCOT	(1,383)	(322.4)%	• unfavorable purchased power of $(750) primarily due to higher energy prices primarily during the February 2021 extreme cold weather event • unfavorable settlement of economic hedges of $(460) due to settled prices relative to hedged prices • unfavorable fuel cost of $(150) primarily due to higher gas prices

(in millions)	Variance	% Change[(a)]	Nine Months Ended September 30, 2021
Other Power Regions	(719)	(29.4)%	• unfavorable purchased power and net capacity impact of $(680) primarily due to higher load, lower generation, higher energy prices, lower cleared capacity volumes, and lower capacity prices • unfavorable RPS expense of $(55) primarily due to higher prices and higher load • unfavorable fuel cost of $(40) primarily due to higher gas prices; partially offset by • favorable settlement of economic hedges of $80 due to settled prices relative to hedged prices
Other	(1,011)	(79.2)%	• unfavorable net gas purchase costs and settlement of economic hedges of $(830) • unfavorable accelerated nuclear fuel amortization associated with announced early plant retirements of $(125)
Mark-to-market[(b)]	1,966		• gains on economic hedging activities of $2,200 in 2021 compared to gains of $234 in 2020
Total	$(1,142)	(16.4)%	

(a) % Change in mark-to-market is not a meaningful measure.

(b) See Note 12 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements for additional information on mark-to-market gains and losses.

The changes in **Operating and maintenance expense,** consisted of the following:

(in millions)	Nine Months Ended September 30, 2021 Increase (Decrease)
Asset impairments	$ 23
Plant retirements and divestitures[(a)]	(706)
ARO update	(49)
Labor, other benefits, contracting, and materials	(29)
Change in environmental liabilities	(18)
Cost management program	(24)
Corporate allocations	(19)
Credit loss expense	46
Acquisition related costs	17
Separation costs	25
Nuclear refueling outage costs, including the co-owned Salem plants	(70)
Other	29
Total decrease	$(775)

(a) Primarily reflects contractual offset of accelerated depreciation and amortization associated with our previous decision to early retire the Byron and Dresden nuclear facilities. See Note 8 — Nuclear Decommissioning of the Notes to Interim Consolidated Financial Statements for additional information.

Depreciation and amortization expense increased for the nine months ended September 30, 2021 compared to the same period in 2020, primarily due to the accelerated depreciation and amortization associated with our previous decision to early retire the Byron and Dresden nuclear facilities. This decision was reversed on September 15, 2021 and depreciation for Byron and Dresden was adjusted beginning September 15, 2021 to reflect the extended useful life estimates. A portion of this accelerated depreciation and amortization is offset in Operating and maintenance expense.

Gain on sales of assets and businesses increased for the nine months ended September 30, 2021 compared to the same period in 2020, primarily due to gains on sales of equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021, and additionally increased for the nine months ended September 30, 2021 compared to the same period in 2020, due to a gain on sale of our solar business.

Interest expense, net decreased for the nine months ended September 30, 2021 compared to the same period in 2020, primarily due to mark-to-market gains related to the EGR IV interest swaps entered into in December 2020 and decreases in interest rates. See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on the interest swaps.

Other, net increased for the nine months ended September 30, 2021 compared to the same period in 2020, due to activity described in the table below:

	Nine Months Ended September 30,	
(in millions)	**2021**	**2020**
Net unrealized (losses) gains on NDT funds[a]	$ 33	$ 1
Net realized gains on sale of NDT funds[a]	349	58
Interest and dividend income on NDT funds[a]	73	69
Contractual elimination of income tax expense[b]	150	46
Net unrealized losses from equity investments[c]	(83)	—
Other	39	25
Total other, net	$561	$199

(a) Unrealized (losses) gains, realized gains, and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units.

(b) Contractual elimination of income tax expense is associated with the income taxes on the NDT funds of the Regulatory Agreement units.

(c) Net unrealized losses from equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021.

Effective income tax rates were (1,350.0)% and 7.7% for the nine months ended September 30, 2021 and 2020, respectively. See Note 10 — Income Taxes of the Notes to Interim Consolidated Financial Statements for additional information.

Net income attributable to noncontrolling interests increased for the nine months ended September 30, 2021 compared to the same period in 2020, primarily due to higher net gains on NDT fund investments for CENG prior to our acquisition of EDF's interest in CENG on August 6, 2021 partially offset by the noncontrolling portion of a wind project impairment.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

(in millions)	**2020**	**2019**	**(Unfavorable) Favorable Variance**
Operating revenues	$17,603	$18,924	$(1,321)
Operating expenses			
Purchased power and fuel	9,585	10,856	1,271
Operating and maintenance	5,168	4,718	(450)
Depreciation and amortization	2,123	1,535	(588)

(in millions)	2020	2019	(Unfavorable) Favorable Variance
Taxes other than income taxes	482	519	37
Total operating expenses	17,358	17,628	270
Gain on sales of assets and businesses	11	27	(16)
Operating income	256	1,323	(1,067)
Other income and (deductions)			
Interest expense	(357)	(429)	72
Other, net	937	1,023	(86)
Total other income and (deductions)	580	594	(14)
Income before income taxes	836	1,917	(1,081)
Income taxes	249	516	267
Equity in losses of unconsolidated affiliates	(8)	(184)	176
Net income	579	1,217	(638)
Net (loss) income attributable to noncontrolling interests	(10)	92	(102)
Net income attributable to membership interest	$ 589	$ 1,125	$ (536)

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. Net income attributable to membership interest decreased by $536 million primarily due to:

- One-time charges and accelerated depreciation and amortization associated with our decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024, partially offset by the absence of accelerated depreciation and amortization due to the early retirement of TMI in September 2019;
- Impairment of the New England asset group;
- Lower capacity revenue;
- Reduction in load due to COVID-19;
- Lower realized energy prices;
- Higher nuclear outage days;
- Impact of our annual update to the nuclear ARO for Non-regulatory Agreement Units;
- Lower net unrealized and realized gains on NDT funds;
- COVID-19 direct costs; and

The decreases were partially offset by:

- Higher mark-to-market gains;
- Unrealized gains resulting from equity investments without readily determinable fair values that became publicly traded entities in the fourth quarter of 2020 and were fair valued based on quoted market prices of the stocks as of December 31, 2020;
- Lower operating and maintenance expense primarily due to previous cost management programs, lower contracting costs, and lower travel costs partially offset by lower NEIL insurance distributions;
- Lower nuclear fuel costs;
- Lower depreciation and amortization expense due to the impact of extending the operating license at Peach Bottom;
- A tax benefit related to a settlement in the first quarter of 2020, partially offset by the absence of a tax benefit related to certain research and development activities recorded in the fourth quarter of 2019.

Operating revenues. The basis for our reportable segments is the integrated management of our 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). Our hedging strategies and risk metrics are also aligned with these same geographic regions. Our five reportable segments are Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 5 — Segment Information of the Notes to Consolidated Financial Statements for additional information on these reportable segments.

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 overall operating revenues or results of operations.

For the years ended December 31, 2020 compared to 2019, Operating revenues by region were as follows:

(in millions)	2020	2019	2020 vs. 2019 Variance	2020 vs. 2019 % Change[(a)]
Mid-Atlantic	$ 4,645	$ 5,075	$ (430)	(8.5)%
Midwest	4,024	4,293	(269)	(6.3)%
New York	1,431	1,596	(165)	(10.3)%
ERCOT	958	1,013	(55)	(5.4)%
Other Power Regions	4,002	4,246	(244)	(5.7)%
Total electric revenues	15,060	16,223	(1,163)	(7.2)%
Other	2,433	2,706	(273)	(10.1)%
Mark-to-market gains (losses)	111	(2)	113	
Total Operating revenues	$17,603	$18,924	$(1,321)	(7.0)%

(a) % Change in mark-to-market is not a meaningful measure

Supply Sources. Our supply sources by region are summarized below:

Supply Source (GWhs)	2020	2019	2020 vs. 2019 Variance	2020 vs. 2019 % Change
Nuclear Generation[(a)]				
Mid-Atlantic	52,202	58,347	(6,145)	(10.5)%
Midwest	96,322	94,890	1,432	1.5%
New York	26,561	28,088	(1,527)	(5.4)%
Total Nuclear Generation	175,085	181,325	(6,240)	(3.4)%
Fossil and Renewables				
Mid-Atlantic	2,206	2,884	(678)	(23.5)%
Midwest	1,240	1,374	(134)	(9.8)%
New York	4	5	(1)	(20.0)%
ERCOT	11,982	13,572	(1,590)	(11.7)%
Other Power Regions	11,121	11,476	(355)	(3.1)%
Total Fossil and Renewables	26,553	29,311	(2,758)	(9.4)%
Purchased Power				
Mid-Atlantic	22,487	14,790	7,697	52.0%
Midwest	770	1,424	(654)	(45.9)%
ERCOT	5,636	4,821	815	16.9%
Other Power Regions	51,079	48,673	2,406	4.9%
Total Purchased Power	79,972	69,708	10,264	14.7%

Supply Source (GWhs)	2020	2019	2020 vs. 2019 Variance	2020 vs. 2019 % Change
Total Supply/Sales by Region[b]				
Mid-Atlantic	76,895	76,021	874	1.1%
Midwest	98,332	97,688	644	0.7%
New York	26,565	28,093	(1,528)	(5.4)%
ERCOT	17,618	18,393	(775)	(4.2)%
Other Power Regions	62,200	60,149	2,051	3.4%
Total Supply/Sales by Region	281,610	280,344	1,266	0.5%

(a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated.

(b) Reflects a decrease in load due to COVID-19.

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for our plants, which reflects ownership percentage of stations operated by us, excluding Salem, which is operated by PSEG. 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. We consider capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. We have 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.

	2020	2019
Nuclear fleet capacity factor	95.4%	95.7%
Refueling outage days	260	209
Non-refueling outage days	19	51

ZEC Prices. We are compensated through state programs for the carbon-free attributes of our nuclear generation. ZEC prices have a significant impact on Operating revenues. The following table presents the average ZEC prices ($/MWh) for each of our major regions in which state programs have been enacted. Prices reflect the weighted average price for the various delivery periods within each calendar year.

State (Region)	2020	2019	2020 vs. 2019 Variance	2020 vs. 2019 % Change
New Jersey (Mid-Atlantic)	$10.00	$10.00	$ —	—
Illinois (Midwest)	16.50	16.50	—	—
New York (New York)	19.59	19.06	0.53	2.8%

Capacity Prices. We participate in capacity auctions in each of our major regions, except ERCOT which does not have a capacity market. We also incur capacity costs associated with load served, except in ERCOT. Capacity prices have a significant impact on our operating revenues and purchased power and fuel. The following table presents the average capacity prices ($/MW Day) for each of our major regions. Prices reflect the weighted average price for the various auction periods within each calendar year.

Location (Region)	2020	2019	2020 vs. 2019 Variance	2020 vs. 2019 % Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic and Midwest)	$159.50	$163.79	$ (4.29)	(2.6)%
ComEd (Midwest)	194.22	207.87	(13.65)	(6.6)%
Rest of State (New York)	47.81	26.95	20.86	77.4%
Southeast New England (Other)	200.69	269.35	(68.65)	(25.5)%

Electricity Prices. The price of electricity has a significant impact on our operating revenues and purchased power cost. The following table presents the average day-ahead around-the-clock price ($/MWh) for each of our major regions.

			2020 vs. 2019	
Location (Region)	**2020**	**2019**	**Variance**	**% Change**
PJM West (Mid-Atlantic)	$20.95	$26.69	$ (5.74)	(21.5)%
ComEd (Midwest)	18.96	23.59	(4.63)	(19.6)%
Central (New York)	16.36	21.80	(5.44)	(25.0)%
North (ERCOT)	22.03	37.80	(15.77)	(41.7)%
Southwest Massachusetts (Other)[a]	23.57	31.51	(7.94)	(25.2)%

(a) Reflects New England, which comprises the majority of the activity in the Other region

For the years ended December 31, 2020 compared to 2019 changes in **Operating revenues** by region were approximately as follows:

	2020 vs. 2019		
(in millions)	**Variance**	**% Change[a]**	**Description**
Mid-Atlantic	$ (429)	(8.5)%	• unfavorable settled economic hedges of $(175) due to settled prices relative to hedged prices • unfavorable retail load revenue of $(205) primarily due to lower volumes • unfavorable wholesale load revenue of $(95) primarily due to lower prices; partially offset by • favorable ZEC revenues of $20 due to the approval of the NJ ZEC program in the second quarter of 2019
Midwest	(269)	(6.3)%	• unfavorable retail load revenue of $(230) primarily due to lower volumes • unfavorable wholesale load revenue, net of generation of $(110) primarily due to lower load volume, partially offset by higher generation due to lower nuclear outage days • unfavorable net capacity revenues of $(50) due to lower prices, partially offset by higher volumes; partially offset by • favorable settled economic hedges of $85 due to settled prices relative to hedged prices
New York	(165)	(10.3)%	• unfavorable retail load revenue of $(70) primarily due to lower volumes • unfavorable generation from jointly-owned nuclear stations of $(50) due to higher outage days • unfavorable settled economic hedges of $(30) due to settled prices relative to hedged prices
ERCOT	(55)	(5.4)%	• unfavorable retail load revenue of $(50) primarily due to lower volumes • unfavorable settled economic hedges of $(30) due to settled prices relative to hedged prices
Other Power Regions	(244)	(5.7)%	• unfavorable wholesale load revenue of $(195) primarily due to lower prices • unfavorable settled economic hedges of $(175) due to settled prices relative to hedged prices; partially offset by • favorable retail load revenue of $130 primarily due to higher volumes

	2020 vs. 2019		
(in millions)	Variance	% Change[a]	Description
Other	(272)	(10.1)%	• unfavorable gas revenue of $(205) primarily due to lower prices • unfavorable revenue of $(55) related to the energy efficiency business
Mark-to-market[b]	113		• gains on economic hedging activities of $111 in 2020 compared to losses of $2 in 2019
Total	$(1,321)	(7.0)%	

(a) % Change in mark-to-market is not a meaningful measure

(b) See Note 16 — Derivative Financial Instruments of the Notes to Audited Consolidated Financial Statements for additional information on mark-to-market gains and losses.

Purchased power and fuel expense. See Operating revenues above for discussion of our reportable segments and hedging strategies and for supplemental statistical data, including supply sources by region, nuclear fleet capacity factor, capacity prices, and electricity prices.

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 overall purchased power and fuel expense or results of operations, and accelerated nuclear fuel amortization associated with nuclear decommissioning.

For the years ended December 31, 2020 compared to 2019, Purchased power and fuel expense by region was as follows:

			2020 vs. 2019	
(in millions)	2020	2019	Variance	% Change[a]
Mid-Atlantic	$2,442	$ 2,420	$ (22)	(0.9)%
Midwest	1,121	1,330	209	15.6%
New York	434	502	68	13.5%
ERCOT	532	705	173	24.5%
Other Power Regions	3,336	3,625	289	7.9%
Total electric purchased power and fuel	7,865	8,582	717	8.3%
Other	1,904	2,061	157	7.6%
Mark-to-market (gains) losses	(184)	213	397	
Total purchased power and fuel	$9,585	$10,856	$1,271	11.7%

(a) % Change in mark-to-market is not a meaningful measure

For the years ended December 31, 2020 compared to 2019 changes in **Purchased power and fuel** by region was approximately as follows:

	2020 vs. 2019		
(in millions)	Variance	% Change[a]	Description
Mid-Atlantic	$ (22)	(0.9)%	• unfavorable purchased power and net capacity obligation of $(130) primarily due to lower nuclear generation as a result of the permanent cease of operations at TMI and higher nuclear outage days; partially offset by • favorable nuclear fuel of $50 primarily due to the permanent cease of generation at TMI in the third quarter of 2019 and higher nuclear outage days • favorable RPS expense of $55 primarily due to lower prices
Midwest	209	15.7%	• favorable purchased power of $110 primarily due to lower retail and wholesale load • favorable settlement of economic hedges of $60 due to settled prices relative to hedged prices
New York	68	13.5%	• favorable purchased power of $85 primarily due to lower retail load and lower prices
ERCOT	173	24.5%	• favorable purchased power of $140 primarily due to availability of generation during peak price periods
Other Power Regions	289	8.0%	• favorable purchased power and net capacity obligation of $105 primarily due to lower prices • favorable fuel cost of $105 due to lower prices and lower generation • favorable RPS expense of $145 primarily due to lower prices; partially offset by • unfavorable settled economic hedges of $(65) due to settled prices relative to hedged prices
Other	157	7.6%	• favorable net gas purchase costs and settlement of economic hedge of $215; partially offset by • unfavorable accelerated nuclear fuel amortization associated with announced early plant retirements of $(75)
Mark-to-market[b]	397		• gains on economic hedging activities of $184 in 2020 compared to losses of $212 million in 2019
Total	$1,271	11.7%	

(a) % Change in mark-to-market is not a meaningful measure

(b) See Note 16 — Derivative Financial Instruments of the Notes to Audited Consolidated Financial Statements for additional information on mark-to-market gains and losses.

The changes in **Operating and maintenance expense**, consisted of the following:

(in millions)	2020 vs. 2019 Increase (Decrease)
Asset Impairments	$499
ARO update	125
Nuclear refueling outage costs, including the co-owned Salem plants	60
Insurance	52
COVID-19 direct costs	46
Litigation settlements	26
Change in environmental liabilities	18

(in millions)	2020 vs. 2019 Increase (Decrease)
Credit loss expense[a]	16
Accretion expense	14
Plant retirements and divestitures	(8)
Pension and non-pension postretirement benefits expense	(19)
Corporate allocations	(35)
Travel costs	(38)
Other	(71)
Labor, other benefits, contracting, materials[b]	(235)
Total increase	$ 450

(a) Increased credit loss expense including impacts from COVID-19.

(b) Primarily reflects decreased costs related to the permanent cease of generation operations at TMI, lower labor costs resulting from previous cost management programs, and decreased contracting costs.

Depreciation and amortization expense for the year ended December 31, 2020 compared to the same period in 2019 increased primarily due to the accelerated depreciation and amortization associated with our decision to early retire the Byron and Dresden nuclear facilities, partially offset by the permanent cease of generation operations at TMI.

Taxes other than income taxes for the year ended December 31, 2020 compared to the same period in 2019 decreased primarily due to decreased sales and power usage.

Gain on sales of assets and businesses for the year ended December 31, 2020 compared to the same period in 2019 decreased primarily due to our gain on sale of certain wind assets in 2019 partially offset by the loss on sale of Oyster Creek.

Other, net for the year ended December 31, 2020 compared to the same period in 2019 decreased due to activity associated with NDT funds as described in the table below.

(in millions)	2020	2019
Net unrealized gains on NDT funds[a]	$391	$ 411
Net realized gains on sale of NDT funds[a]	70	253
Interest and dividend income on NDT funds[a]	90	110
Contractual elimination of income tax expense[b]	180	216
Unrealized gains from equity investments[c]	186	—
Other	20	33
Total other, net	$937	$1,023

(a) Unrealized gains, realized gains and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units.

(b) Contractual elimination of income tax expense is associated with the income taxes on the NDT funds of the Regulatory Agreement Units.

(c) Unrealized gains resulting from equity investments without readily determinable fair values that became publicly traded entities in the fourth quarter of 2020 and were fair valued based on quoted market prices of the stocks as of December 31, 2020.

Interest Expense for the year ended December 31, 2020 compared to the same period in 2019 decreased primarily due to the redemption of long-term debt in 2020.

Effective income tax rates were 29.8% and 26.9% for the years ended December 31, 2020 and 2019, respectively. The change in 2020 is primarily related to one-time income tax settlements partially offset by the absence of research and development refund claims. See Note 14 — Income Taxes of the Notes to Audited Consolidated Financial Statements for additional information.

Equity in losses of unconsolidated affiliates for the year ended December 31, 2020 compared to the same period in 2019 increased primarily due to the impairment of equity method investments in certain distributed energy companies in the third quarter of 2019.

Net income attributable to noncontrolling interests for the year ended December 31, 2020 compared to the same period in 2019 decreased primarily due to lower unrealized losses on NDT fund investments for CENG.

Liquidity and Capital Resources

All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

Our operating and capital expenditures requirements are provided by internally generated cash flows from operations, the sale of certain receivables, as well as funds from external sources in the capital markets and through bank borrowings. Our business is capital intensive and requires considerable capital resources. We annually evaluate our financing plan and credit line sizing, focusing on maintaining our investment grade ratings while meeting our cash needs to fund capital requirements, retire debt, 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 our 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.). Our access to external financing on reasonable terms depends on our credit ratings and current overall capital market business conditions. If these conditions deteriorate to the extent that we no longer have access to the capital markets at reasonable terms, we have access to credit facilities with aggregate bank commitments of $6.6 billion. As a result of disruptions in the commercial paper markets due to COVID-19 in March of 2020, we borrowed $1.5 billion on our revolving credit facility to refinance commercial paper. We repaid the $1.5 billion borrowed on the revolving credit facility on April 3, 2020 using funds from short-term loans issued in March 2020, cash proceeds from the sale of certain customer accounts receivable, and borrowings from the Exelon intercompany money pool. See Note 6 — Accounts Receivable of the Notes to Audited Consolidated Financial Statements for additional information on the sale of customer accounts receivable. See Significant 2020 and 2021 Transactions and Developments for additional information on COVID-19. We continue to utilize our credit facilities to support our commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the “Credit Matters” section below for additional information. We expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements.

We primarily use our capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, fund pension and OPEB obligations, and invest in new and existing ventures. See Note 13 — Debt and Credit Agreements of the Notes to Interim Consolidated Financial Statements and Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information of our debt and credit agreements.

Despite disruptions in the financial markets due to COVID-19, we issued long-term debt of $1.7 billion and were able to successfully complete our planned long-term debt issuances in 2020.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are typically based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant’s owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 8 — Nuclear Decommissioning of the Notes to Interim Consolidated Financial Statements and Note 10 — Asset Retirement Obligations of the Notes to Audited Consolidated Financial Statements for additional information.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT funds could appreciate in value. A shortfall could require that we address the shortfall by providing additional financial assurances such as surety bonds, letters of credit, or parent company guarantees for our share of the funding assurance. However, the amount of any assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the NDT fund investment performance going forward. No later than two years after shutting down a plant, we must submit a PSDAR to the NRC that includes the planned option for decommissioning the site. As a result of the early retirement reversal, additional financial assurance is no longer required for Byron.

Upon issuance of any required financial assurance, subject to satisfying various regulatory preconditions, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, under the regulations, the NRC must approve an exemption in order for us to utilize the NDT funds to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs, if applicable). If a unit does not receive this exemption, those costs would be borne by us without reimbursement from or access to the NDT funds.

As of September 30, 2021, we are not required to provide any additional financial assurances for TMI Unit 1 under the SAFSTOR scenario which is the planned decommissioning option as described in the TMI Unit 1 PSDAR filed by us with the NRC on April 5, 2019. On October 16, 2019, the NRC granted our exemption request to use the TMI Unit 1 NDT funds for spent fuel management costs. An additional exemption request to allow the TMI Unit 1 NDT funds to be used for site restoration costs was submitted to the NRC on May 20, 2021 and is pending NRC review.

Cash Flows from Operating Activities

Our cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Our future cash flows from operating activities may be affected by future demand for, and market prices of, energy and our ability to continue to produce and supply power at competitive costs, as well as to obtain collections from customers and the sale of certain receivables. See Note 3 — Regulatory Matters and Note 15 — Commitments and Contingencies of the Notes to Interim Consolidated Financial Statements and Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements for additional information of regulatory and legal proceedings and proposed legislation.

The following tables provide a summary of the change in cash flows from operating activities for the nine months ended September 30, 2021 and 2020 and the years ended December 31, 2020 and 2019:

(Decrease) increase in cash flows from operating activities for the nine months ended September 30, 2021 and 2020 (in millions)	
Net income	$ (607)
Adjustments to reconcile net income to cash:	
Non-cash operating activities	(527)
Pension and non-pension postretirement benefit contributions	12
Income taxes	65
Changes in working capital and other noncurrent assets and liabilities	(611)
Option premiums paid, net	(55)
Collateral received, net	1,334
Decrease in cash flows from operating activities	$ (389)

(Decrease) increase in cash flows from operating activities for the years ended December 31, 2020 and 2019 (in millions)	
Net income	$ (638)
Adjustments to reconcile net income to cash:	
Non-cash operating activities	328
Pension and non-pension postretirement benefit contributions	(80)
Income taxes	(116)
Changes in working capital and other noncurrent assets and liabilities	(2,633)
Option premiums paid, net	(110)
Collateral received, net	960
Decrease in cash flows from operating activities	$(2,289)

Changes in our cash flows from operations were generally consistent with changes in results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the nine months ended September 30, 2021 and 2020 and the years ended December 31, 2020 and 2019 were as follows:

- See Note 17 — Supplemental Financial Information of the Notes to Interim Consolidated Financial Statements and Note 22 — Supplemental Financial Information of the Notes to Audited Consolidated Financial Statements and the Consolidated Statements of Cash Flows for additional information on **non-cash operating activity**.
- See Note 10 — Income Taxes of the Notes to Interim Consolidated Financial Statements and Note 14 — Income Taxes of the Notes to Audited Consolidated Financial Statements and the Consolidated Statements of Cash Flows for additional information on **income taxes.**
- **Changes in working capital and other noncurrent assets and liabilities** for the nine months ended September 30, 2021 and 2020 include a decrease in Accounts receivable resulting from the impact of cash received in 2020 related to the revolving accounts receivable financing arrangement entered into on April 8, 2020 and an increase in Accounts payable and accrued expenses resulting from the impact of certain penalties for natural gas delivery associated with the February 2021 extreme cold weather event. See Note 6 — Accounts Receivable and Note 3 — Regulatory Matters of the Notes to Interim Consolidated Financial Statements for additional information on the sales of customer accounts receivable and on the February 2021 extreme cold weather event, respectively.

Changes in working capital and other noncurrent assets and liabilities for the years ended December 31, 2020 and 2019 are primarily due to the revolving accounts receivable financing arrangement entered into on April 8, 2020.

- Depending upon whether we are in a net mark-to-market liability or asset position, **collateral** may be required to be posted with or collected from our counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets. See Note 12 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements and Note 16 — Derivative Financial Instruments of the Notes to Audited Consolidated Financial Statements for additional information on collateral.

Pension and Other Postretirement Benefits

See Note 15 — Retirement Benefits of the Notes to Audited Consolidated Financial Statements for additional information on planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to OPEB plans in 2021.

Cash Flows from Investing Activities

The following tables provide a summary of the change in cash flows from investing activities for the nine months ended September 30, 2021 and 2020 and the years ended December 31, 2020 and 2019:

Increase (decrease) in cash flows from investing activities for the nine months ended September 30, 2021 and 2020 (in millions)	
Capital expenditures	$ 126
Proceeds from NDT fund sales, net	(66)
Proceeds from sales of assets and businesses	756
Collection of DPP	534
Increase in cash flows from investing activities	$1,350

Increase (decrease) in cash flows from investing activities for the years ended December 31, 2020 and 2019 (in millions)	
Capital expenditures	$ 98
Proceeds from NDT fund sales, net	(87)
Acquisitions of assets and businesses, net	41
Proceeds from sales of assets and businesses	(6)
Collection of DPP	3,771
Other investing activities	8
Increase in cash flows from investing activities	$3,825

Significant investing cash flow impacts for the nine months ended September 30, 2021 and 2020 and the years ended December 31, 2020 and 2019 were as follows:

- Variances in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. Refer below for additional information on projected capital expenditure spending.
- **Proceeds from sales of assets and businesses** for the nine months ended September 30, 2021 and 2020 increased primarily due to the sale of a significant portion of our solar business and a biomass facility and proceeds received on sales of equity investments. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Interim Consolidated Financial Statements for additional information on the sale of our solar business and biomass facility.
- See Note 6 — Accounts Receivable of the Notes to Interim Consolidated Financial Statements for additional information on the **Collection of DPP**.

Capital Expenditure Spending

Our most recent estimate of capital expenditures for plant additions and improvements for 2021 is approximately $1.5 billion. Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Approximately 52% of projected 2021 capital expenditures are for the acquisition of nuclear fuel, with the remaining amounts primarily reflecting additions and upgrades to existing generation facilities (including material condition improvements during nuclear refueling outages). We anticipate that we will fund capital expenditures with internally generated funds and borrowings.

Cash Flows from Financing Activities

The following tables provide a summary of the change in cash flows from financing activities for the nine months ended September 30, 2021 and 2020 and the years ended December 31, 2020 and 2019:

Increase (decrease) in cash flows from financing activities for the nine months ended September 30, 2021 and 2020 (in millions)	
Changes in short-term borrowings, net	$ 320
Long-term debt, net	1,271
Changes in intercompany money pool	(285)
Acquisition of CENG's noncontrolling interest	(885)
Distributions to member	33
Other financing activities	3
Increase in cash flows from financing activities	$ 457

Increase (decrease) in cash flows from financing activities for the years ended December 31, 2020 and 2019 (in millions)	
Changes in short-term borrowings, net	$ 200
Long-term debt, net	(958)
Changes in intercompany money pool	385
Distributions to member	(835)
Contributions from member	23
Other financing activities	(19)
Decrease in cash flows from financing activities	$(1,204)

Significant financing cash flow impacts for the nine months ended September 30, 2021 and 2020 and the years ended December 31, 2020 and 2019 were as follows:

- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due in less than 365 days. Refer to Note 13 — Debt and Credit Agreements of the Notes to Interim Consolidated Financial Statements and Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on short-term borrowings.
- **Long-term debt, net,** varies due to debt issuances and redemptions each year. Refer to Note 13 — Debt and Credit Agreements of the Notes to Interim Consolidated Financial Statements for debt issuances for the nine months ended September 30, 2021 and 2020 and to tables below for debt issuances for the years ended December 31, 2020 and 2019. Refer to tables below for debt redemptions for the nine months ended September 30, 2021 and 2020 and for the years ended December 31, 2020 and 2019.
- **Changes in intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.
- See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Interim Consolidated Financial Statements for additional information related to **the acquisition** of CENG noncontrolling interest.
- For the nine months ended September 30, 2021 and 2020 and the years ended December 31, 2020 and 2019, other financing activities primarily consists of debt issuance costs. Refer to Note 13 — Debt and Credit Agreements of the Notes to Interim Consolidated Financial Statements for additional information on debt issuances for the nine months ended September 30, 2021 and 2020 and to tables below for additional information on debt issuances for the years ended December 31, 2020 and 2019.

Debt Issuances and Redemptions

See Note 13 — Debt and Credit Agreements of the Notes to Interim Consolidated Financial Statements and Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on our long-term debt. See Note 13 — Debt and Credit Agreements of the Notes to Interim Consolidated Financial Statements for additional information on debt issuances for the nine months ended September 30, 2021 and tables below for additional information on debt issuances for the years ended December 31, 2020 and 2019. See tables below for additional information on debt redemptions for the nine months ended September 30, 2021 and for the years ended December 31, 2020 and 2019.

During 2020, the following long-term debt was issued:

Type	Interest Rate	Maturity	Amount (in millions)	Use of Proceeds
Senior Notes	3.25%	June 1, 2025	$ 900	Repay existing indebtedness and for general corporate purposes.
EGR IV Nonrecourse Debt[(a)]	LIBOR + 2.75%	December 15, 2027	750	Repay existing indebtedness and for general corporate purposes.
Energy Efficiency Project Financing[(b)]	3.95%	February 28, 2021	3	Funding to install energy conservation measures for the Fort Meade project.
Energy Efficiency Project Financing[(b)]	2.53%	March 31, 2021	3	Funding to install energy conservation measures for the Fort AP Hill project.

(a) See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information of nonrecourse debt.

(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

During 2019, the following long-term debt was issued:

Type	Interest Rate	Maturity	Amount (in millions)	Use of Proceeds
Energy Efficiency Project Financing[(a)]	3.95%	February 28, 2021	$ 4	Funding to install energy conservation measures for the Fort Meade project.
Energy Efficiency Project Financing[(a)]	3.46%	February 28, 2021	39	Funding to install energy conservation measures for the Marine Corps. Logistics Project.
Energy Efficiency Project Financing[(a)]	2.53%	March 31, 2021	2	Funding to install energy conservation measures for the Fort AP Hill project.

(a) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

During the nine months ended September 30, 2021, the following long-term debt was retired and/or redeemed:

Type[a]	Interest Rate		Maturity	Amount (in millions)
Continental Wind Nonrecourse Debt[b]	6.00%		February 28, 2033	$35
EGR IV Nonrecourse Debt[b]	3 month LIBOR + 2.50%	(c)	December 15, 2027	17
SolGen Nonrecourse Debt[b]	3.93%		September 30, 2036	7
Antelope Valley DOE Nonrecourse Debt[b]	2.29% – 3.56%		January 5, 2037	13
West Medway II Nonrecourse Debt[b]	LIBOR + 3%	(d)	March 31, 2026	8
RPG Nonrecourse Debt[a]	4.11%		March 31, 2035	9

(a) On October 5, 2021, we redeemed $11 million of 2.29% — 3.56% Antelope Valley DOE nonrecourse debt.

(b) See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on nonrecourse debt.

(c) The rate was amended to 3 month LIBOR + 2.50% on June 16, 2021.

(d) The nonrecourse debt has an average blended interest rate.

During 2020, the following long-term debt was retired and/or redeemed:

Type	Interest Rate	Maturity	Amount (in millions)
Senior Notes	2.95%	January 15, 2020	$1,000
Senior Notes	4.00%	October 1, 2020	550
Senior Notes[a]	5.15%	December 1, 2020	550
Tax-Exempt Bonds	2.50% – 2.70%	December 1, 2025 – June 1, 2036	412
EGR IV Nonrecourse Debt[b]	3 month LIBOR + 3.00%	November 30, 2024	796
Continental Wind Nonrecourse Debt[b]	6.00%	February 28, 2033	33
Antelope Valley DOE Nonrecourse Debt[b]	2.29% – 3.56%	January 5, 2037	23
RPG Nonrecourse Debt[b]	4.11%	March 31, 2035	9
Energy Efficiency Project Financing	3.71%	December 31, 2020	4
NUKEM	3.15%	September 30, 2020	3
SolGen Nonrecourse Debt	3.93%	September 30, 2036	3
Energy Efficiency Project Financing	4.12%	November 30, 2020	1

(a) The senior notes are legacy Constellation mirror debt that were previously held at Exelon and Generation. As part of the 2012 Constellation merger, Exelon and Generation assumed intercompany loan agreements that mirrored the terms and amounts of external obligations held by Exelon, resulting in notes payable to related parties in our Consolidated Balance Sheets.

(b) See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information of nonrecourse debt.

During 2019, the following long-term debt was retired and/or redeemed:

Type	Interest Rate	Maturity	Amount (in millions)
Antelope Valley DOE Nonrecourse Debt[a]	2.33% – 3.56%	January 5, 2037	$ 23
Kennett Square Capital Lease	7.83%	September 20, 2020	5
Continental Wind Nonrecourse Debt[a]	6.00%	February 28, 2033	32
Pollution control notes	2.50%	March 1, 2019	23
RPG Nonrecourse Debt[a]	4.11%	March 31, 2035	10
Energy Efficiency Project Financing	3.46%	April 30, 2019	39
EGR IV Nonrecourse debt[a]	3 month LIBOR +3.00%	November 30, 2024	38
Hannie Mae, LLC Defense Financing	4.12%	November 30, 2019	1
Energy Efficiency Project Financing	3.72%	July 31, 2019	25
NUKEM	3.15%	September 30, 2020	36
SolGen Nonrecourse Debt[a]	3.93%	September 30, 2036	6
Energy Efficiency Project Financing	4.17%	October 31, 2019	1
Energy Efficiency Project Financing	3.53%	March 31, 2020	1
Energy Efficiency Project Financing	4.26%	September 30, 2019	1
Senior Notes	5.20%	October 1, 2019	600
Dominion Federal Corp	3.17%	October 31, 2019	18
Fort Detrick Project Financing	3.55%	October 31, 2019	1

(a) See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information of nonrecourse debt.

From time to time and as market conditions warrant, we may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt.

Credit Matters

We fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $6.6 billion in aggregate total commitments of which $4.3 billion was available to support additional commercial paper as of September 30, 2021, and of which no financial institution has more than 8% of the aggregate commitments. We had access to the commercial paper markets and had availability under our revolving credit facilities during the nine months ended September 30, 2021 and the year ended December 31, 2020 to fund our short-term liquidity needs, when necessary. We used our available credit facilities to manage short-term liquidity needs as a result of the impacts of the February 2021 extreme cold weather event and continue to believe we have sufficient cash on hand and available capacity on our revolver to meet our liquidity requirements. We routinely review the sufficiency of our liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. We have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See “Risk Factors” in this information statement for additional information regarding the effects of uncertainty in the capital and credit markets.

We believe our cash flow from operating activities, access to credit markets and our credit facilities provide sufficient liquidity. If we lost our investment grade credit rating as of September 30, 2021, we would have been required to provide incremental collateral of approximately $3.0 billion to meet collateral obligations for derivatives, non-derivatives, normal purchases and normal sales contracts, and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within the $4.3 billion of available credit capacity of our revolver.

Project Financing

Project financing is used to help mitigate risk of specific generating assets. Project financing is based upon a nonrecourse financial structure, in which project debt is paid back from the cash generated by the specific asset or portfolio of assets. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against us 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. Additionally, project finance has credit facilities. See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on nonrecourse debt and credit facilities .

Credit Facilities

We meet our short-term liquidity requirements primarily through the issuance of commercial paper and, historically, through borrowings from the Exelon intercompany money pool. We may use our credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 13 — Debt and Credit Agreements of the Notes to Interim Consolidated Financial Statements and Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on our short-term borrowing activity and credit facilities.

Capital Structure

At December 31, 2020, our capital structure consisted of the following:

	Percentage of Capital Structure
Long-term debt	27%
Long-term debt to affiliates	1%
Member’s equity	68%
Commercial paper and notes payable	4%

Security Ratings

Our access to the capital markets, including the commercial paper market, and our financing costs in those markets, may depend on our securities ratings.

Our borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading could increase fees and interest charges under our credit agreements.

As part of the normal course of business, we enter into contracts that contain express provisions or otherwise permit us and our counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if we are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 16 — Derivative Financial Instruments of the Notes to Audited Consolidated Financial Statements for additional information on collateral provisions.

S&P lowered Generation’s senior unsecured debt rating to ‘BBB’ from ‘BBB+’ on November 4, 2020, following public announcement by Exelon of a strategic review of its corporate structure and consideration of separating the competitive generation and customer-facing businesses, bringing Generation's rating in-line with its stand-alone credit profile. The change was the result of S&P's Group Rating Methodology and the revision of the strategic relationship between the Company and Exelon from "core" to "moderately strategic," removing any rating benefit from Exelon. The Group Rating Methodology and the associated impacts are unique to S&P.

Subsequently on February 24, 2021, S&P lowered Generation's senior unsecured debt rating to 'BBB-' from 'BBB' in response to the financial impacts of the February 2021 weather event and Texas-based generating assets outages. See "Significant 2020 and 2021 Transactions and Developments — Impacts of the February 2021 Extreme Weather Event and Texas-based Generating Assets Outages" for additional information.

The S&P ratings changes did not materially impact our financial statements. Furthermore, there were no material increases in required collateral or financial assurances or material impacts to our anticipated access to liquidity or cost of financing.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable than the cost of external financing, we have historically participated in Exelon's intercompany money pool. Maximum amounts contributed to and borrowed from the money pool and the net contribution or borrowing as of September 30, 2021 and December 31, 2020, are presented in the following tables:

For the Nine Months Ended September 30, 2021		As of September 30, 2021
Maximum Contributed (in millions)	Maximum Borrowed (in millions)	Borrowed (in millions)
$ —	$(426)	$ —

For the Year Ended December 31, 2020		As of December 31, 2020
Maximum Contributed (in millions)	Maximum Borrowed (in millions)	Borrowed (in millions)
$254	$(980)	$(285)

Contractual Obligations and Off-Balance Sheet Arrangements

The following table summarizes the future estimated cash payments as of December 31, 2020 under existing contractual obligations, including payments due by period.

		Payment due within			
(in millions)	Total	2021	2022 – 2023	2024 – 2025	2026 and beyond
Long-term debt	$ 6,066	$ 195	$1,024	$ 900	$3,947
Interest payments on long-term debt[a]	3,536	270	474	443	2,349
Operating leases[b]	731	47	114	109	461
Purchase power obligations[c]	1,613	512	823	264	14
Fuel purchase agreements[d]	4,450	928	1,207	1,022	1,293
Other purchase obligations[e]	2,286	1,208	231	155	692
SNF obligation	1,208	—	—	—	1,208
Total contractual obligations	$19,890	$3,160	$3,873	$2,893	$9,964

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2020.

(b) Capacity payments associated with contracted generation lease agreements are net of sublease and capacity offsets of $98 million, $55 million, $44 million, $44 million, $44 million and $179 million for 2021, 2022, 2023, 2024, 2025 and thereafter, respectively and $464 million in total.

(c) Purchase power obligations primarily include expected payments for REC purchases and capacity payments associated with contracted generation agreements, which may be reduced based on plant availability. Expected payments exclude payments on renewable generation contracts that are contingent in nature.

(d) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, including those related to CENG.

(e) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into with third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

See Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements for additional information of other commitments potentially triggered by future events and SNF obligation. See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on long-term debt and interest payments on long-term debt. See Note 11 — Leases of the Notes to Audited Consolidated Financial Statements for additional information on operating leases.

Sales of Customer Accounts Receivable

On April 8, 2020, we entered into an accounts receivable financing facility with a number of financial institutions and a commercial paper conduit to sell certain receivables, which expires on April 7, 2021 unless renewed by the mutual consent of the parties in accordance with its terms. The facility allows us to obtain financing at lower cost and diversify our sources of liquidity. See Note 6 — Accounts Receivable of the Notes to Audited Consolidated Financial Statements for additional information.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates, and equity prices. The RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. Historically, the RMC has been chaired by the chief executive officer of Exelon and included the chief risk officer, chief strategy officer, chief commercial officer, chief financial officer, and chief executive officer of Constellation and reported to the Finance and Risk Committee of the Exelon Board on the scope of the risk management activities.

Commodity Price Risk

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors.

Electricity available from our owned or contracted generation supply in excess of our obligations to customers is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, we enter into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards, and options, with approved counterparties to hedge anticipated exposures. We use derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. We expect the settlement of the majority of our economic hedges will occur during 2021 through 2023.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on our own and contracted generation positions which have not been hedged. Our hedging program involves the hedging of commodity price risk for our expected generation, typically on a ratable basis over three-year periods. As of September 30, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 96%-99% for the remainder of 2021. 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 generation 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, which include economic hedges and certain non-derivative contracts, including our sales to ComEd, PECO, BGE, Pepco, DPL and ACE to serve their retail load.

A portion of our hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for our entire economic hedge portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on September 30, 2021 market conditions and hedged position would be immaterial for 2021. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. We actively manage our portfolio to mitigate market price risk exposure for our unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in our portfolio. See Note 12 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements for additional information.

Fuel Procurement

We procure natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are 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 are subject to price fluctuations and availability restrictions. Supply market conditions may make our 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 60% of our uranium concentrate requirements from 2021 through 2025 are supplied by three suppliers. In the event of non-performance by these or other suppliers, we believe that replacement uranium concentrates 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 our financial statements.

Trading and Non-Trading Marketing Activities

The following table detailing our trading and non-trading marketing activities are included to address the recommended disclosures by the energy industry’s Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in our commodity mark-to-market net asset or liability balance sheet position from December 31, 2018 to September 30, 2021. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 12 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements and Note 16 — Derivative Financial Instruments of the Notes to Audited Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of September 30, 2021 and as of December 31, 2020 and 2019.

(in millions)	Mark-to-market Energy Contract Net Assets (Liabilities)
Balance as of December 31, 2018[a]	$ 548
Total change in fair value during 2019 of contracts recorded in result of operations	(427)
Reclassification to realized at settlement of contracts recorded in results of operations	226
Changes in allocated collateral	572
Net option premium received	29
Option premium amortization	(22)
Upfront payments and amortizations[b]	(58)
Balance as of December 31, 2019[a]	$ 868
Total change in fair value during 2020 of contracts recorded in result of operations	(203)
Reclassification to realized at settlement of contracts recorded in results of operations	469
Changes in allocated collateral	(513)
Net option premium paid	139
Option premium amortization	(104)
Upfront payments and amortizations[b]	73
Balance as of December 31, 2020[a]	$ 729
Total change in fair value during 2021 of contracts recorded in results of operations	1,434
Reclassification to realized at settlement of contracts recorded in results of operations	(186)
Changes in allocated collateral	(2,061)
Net option premium paid	186
Option premium amortization	(45)
Upfront payments and amortizations[b]	(107)
Balance as of September 30, 2021[a]	$ (50)

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) Includes derivative contracts acquired or sold through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

Fair Values

The following table presents maturity and source of fair value for mark-to-market commodity contract net assets (liabilities). The table provides two fundamental pieces of information. First, the table provides the source of fair value used in determining the carrying amount of our total mark-to-market net assets (liabilities), net of allocated collateral. Second, the table shows the maturity, by year, of our commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 18 — Fair Value of Financial Assets and Liabilities of the Notes to Audited Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

(in millions)	Maturities Within 2021	2022	2023	2024	2025	2026 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$ 302	$ 578	$ 63	$ 53	$38	$ 23	$ 1,057
Prices provided by external sources (Level 2)	17	737	40	(40)	—	—	754
Prices based on model or other valuation methods (Level 3)	(565)	(1,293)	39	8	5	(55)	(1,861)
Total	$(246)	$ 22	$142	$ 21	$43	$(32)	$ (50)

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.

(b) Amounts are shown net of collateral paid/(received) from counterparties (and offset against mark-to-market assets and liabilities) of $(1,645) million at September 30, 2021.

Credit Risk

We would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements for a detailed discussion of credit risk.

The following tables provide information on our credit exposure for all derivative instruments, normal purchases and normal sales agreements, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the table below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, and commodity exchanges, which are discussed below.

Rating as of September 30, 2021 (in millions)	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 701	$254	$447	—	$ —
Non-investment grade	23	2	21	—	—
No external ratings					
Internally rated – investment grade	110	1	109	—	—
Internally rated – non-investment grade	309	48	261	—	—
Total	$1,143	$305	$838	—	$ —

(a) As of September 30, 2021, credit collateral held from counterparties where we had credit exposure included $188 million of cash and $117 million of letters of credit.

Rating as of September 30, 2021 (in millions)	Maturity of Credit Risk Exposure Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$579	$ 69	$53	$ 701
Non-investment grade	23	—	—	23
No external ratings				
Internally rated – investment grade	96	10	4	110
Internally rated – non-investment grade	251	49	9	309
Total	$949	$128	$66	$1,143

Net Credit Exposure by Type of Counterparty (in millions)	As of September 30, 2021
Financial institutions	$ 53
Investor-owned utilities, marketers, power producers	652
Energy cooperatives and municipalities	62
Other	71
Total	$838

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physical or financial contracts for the sale and purchase of electricity, natural gas, and other commodities. In accordance with the contracts and applicable law, if we are downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on our net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. See Note 12 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements for additional information regarding collateral requirements and Note 15 — Commitments and Contingencies of the Notes to Interim Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

We transact output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on our financial statements. As market prices rise above or fall below contracted price levels, we are required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with us. To post collateral, we depend on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See “Liquidity and Capital Resources — Credit Matters” of “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information.

RTOs and ISOs

We participate in all, or some, of the established, wholesale spot energy markets that are administered by PJM, ISO-NE, NYISO, CAISO, MISO, SPP, AESO, OIESO, and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no spot energy market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on our financial statements.

Exchange Traded Transactions

We enter into commodity transactions on NYMEX, ICE, NASDAQ, NGX, and the Nodal exchange (“the Exchanges”). The Exchange clearinghouses act as the counterparty to each trade. Transactions on the Exchanges must adhere to comprehensive collateral and margining requirements. As a result, transactions on Exchanges are significantly collateralized and have limited counterparty credit risk.

Interest Rate and Foreign Exchange Risk

We use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. We may also utilize interest rate swaps to manage our interest rate exposure. A hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $1 million decrease in our pre-tax income for the nine months ended September 30, 2021 and a $2 million decrease in our pre-tax income for the year ended December 31, 2020. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, we utilize foreign currency derivatives, which are typically designated as economic hedges. See Note 16 — Derivative Financial Instruments of the Notes to Interim Consolidated Financial Statements for additional information.

Equity Price Risk

We maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of September 30, 2021, our NDT funds are reflected at fair value in the Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate us for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the investment performance of the trust funds and periodically reviews asset allocation in accordance with our NDT fund investment policy. A hypothetical 25 basis points increase in interest rates and 10% decrease in equity prices would result in a $863 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See “Liquidity and Capital Resources” under “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for additional information of equity price risk as a result of the current capital and credit market conditions.

MANAGEMENT

Executive Officers Following the Separation

The following table and accompanying narrative present information, as of December 6, 2021, regarding the individuals who are expected to serve as our executive officers following the completion of the separation. Some of our executive officers are currently executive officers of Exelon but will cease to hold such positions at Exelon upon the consummation of the separation.

Name	Age	Position with Constellation
Joseph Dominguez	56	President and Chief Executive Officer
Daniel Eggers	46	Executive Vice President and Chief Financial Officer
Kathleen Barrón	51	Executive Vice President and Chief Strategy Officer
Bryan Hanson	56	Executive Vice President and Chief Generation Officer
Mike Koehler	54	Executive Vice President and Chief Administration Officer
James McHugh	50	Executive Vice President and Chief Commercial Officer
David Dardis	49	Executive Vice President and General Counsel

Joseph Dominguez. Mr. Dominguez has more than 20 years of experience in the energy industry, having most recently served since 2018 as Chief Executive Officer of ComEd, an Exelon company that serves more than 4,000,000 residential and business customers in Illinois. Prior to serving in that position, Mr. Dominguez served from 2012 to 2018 as Exelon's Executive Vice President of Governmental and Regulatory Affairs and Public Policy where he led the development and implementation of federal, state, and regional governmental, regulatory, and public policy strategies.

Daniel Eggers. Mr. Eggers is a seasoned financial industry professional and most recently served since 2018 as Exelon's Senior Vice President of Corporate Finance where he led Exelon's management of investor relations, treasury, corporate planning, corporate financial operations, and insurance. From 2016 to 2018, Mr. Eggers served as Exelon's Senior Vice President of Investor Relations where he served as the primary interface with Exelon's institutional investors and sell-side analysts. Prior to joining Exelon, Mr. Eggers spent 18 years with Credit Suisse where he served in a variety of positions including managing director in the Investment Banking Division. He was also a member of the Equity Research department where he covered regulated utility, integrated power and independent power producer stocks, and served as co-head of U.S. Energy Research where he had macro coverage responsibilities for the power sector as well as wind energy and carbon policy.

Kathleen Barrón. Ms. Barrón leads the Company's management of strategy, public policy, sustainability, corporate development, communications, corporate relations and philanthropy. Ms. Barrón joined Exelon in 2010 and served in a variety of positions, most recently as Exelon's Executive Vice President of Government and Regulatory Affairs since 2018 where she led the development and implementation of federal, state and regional governmental, regulatory and public policy strategies, and managed wholesale market design advocacy in each of the regional markets where Generation operates. Prior to joining Exelon, she served as Deputy General Counsel at the Federal Energy Regulatory Commission where she advised the Commission on all aspects of its responsibilities and represented the Commission before Congress, government agencies, and industry groups.

Bryan Hanson. Mr. Hanson has more than 30 years of progressive experience in the nuclear power industry and is responsible for the safe, efficient and reliable operation of the Company's power generation fleet. Prior to his current role, Mr. Hanson was president and chief nuclear officer of Generation's nuclear fleet from 2015 to 2020 where he was responsible for ensuring that Generation maintained high levels of performance and safety across its nuclear fleet. During his tenure with Exelon, which began in 2006, Mr. Hanson also served as the Nuclear Chief Operating Officer, Senior Vice President of Midwest Operations, Site Vice President for Braidwood Generating Station and Site Vice President for Clinton Power Station.

Mike Koehler. Mr. Koehler leads the Company's technology, tech platforms, cyber security, supply, real estate and facilities, transportation, and physical security operations. Prior to this role, he served from

2016 to 2021 as Exelon's Senior Vice President and Chief Information and Chief Digital Officer where he was responsible for the strategic direction of information technology and digital strategy including resources and technology innovation and for ensuring effective and secure delivery and support of technology systems. Before joining Exelon, he served as President of EMC Professional Services, where he managed its Global Services group's broad portfolio of professional services, practices and delivery, as well as go-to-market execution, to maximize benefits from customers' investments in EMC's technology. Mr. Koehler serves on the board of directors of Coresite Realty Corporation , a business that owns, acquires, constructs and operates data centers in some of the largest markets in the U.S., since 2010.

James McHugh. Mr. McHugh has more than 25 years of experience in the energy industry and has led the Company's competitive retail and commodities business since 2018. He previously served from 2016 to 2018 as Senior Vice President of wholesale trading where he was responsible for the wholesale trading and portfolio management of the Company's generation, load, transactions and contracted assets. Since joining Exelon in 2004, Mr. McHugh has served in a variety of positions of increasing responsibility withing the organization, including Senior Vice President of portfolio management and strategy, director of the Midwest and mid-Atlantic regional trading and director of portfolio management.

David Dardis. Mr. Dardis is a veteran energy industry lawyer with nearly 20 years of experience representing investor-owned electric and gas utilities, competitive retail suppliers, and merchant generation companies. He has served as General Counsel of Generation since 2020, and previously served as General Counsel of Exelon's competitive retail and commodities business from 2016 to 2020 where he managed legal affairs and had oversight responsibility for wholesale and retail compliance programs. Mr. Dardis joined Exelon in 2007 and held various leadership roles leading large legal teams and advising senior management on key issues. Prior to that, Mr. Dardis was legal advisor to Chairman Joseph Kelliher of the Federal Energy Regulatory Commission where he advised on the organized electric markets in the Eastern Interconnection, implementation of the Energy Policy Act of 2005 and the development of the agency's enforcement program.

Board of Directors Following the Separation

Although we have not yet finalized the full expected composition of the Company's Board of Directors following the separation, we expect the following individuals will serve on the Board as of the date of the distribution. With the exception of Joseph Dominquez, each of the other individuals currently serves on the Exelon Board of Directors and is expected to resign as of the date of the distribution. Robert Lawless is expected to serve as Chair of the Board of Directors.

Name	Age	Independent Under Nasdaq Rules
Joseph Dominguez	56	No
Yves de Balmann	75	Yes
Laurie Brlas	64	Yes
Robert Lawless	75	Yes
John Richardson	61	Yes

Yves de Balmann. Mr. de Balmann has served on the Exelon Board since 2012. He has extensive experience in corporate finance, including the derivatives and capital markets as well as industry experience as a former director of Constellation Energy Group prior to its merger with Exelon in 2012. His deep knowledge of strategic planning, compensation, governance, and investor insights will provide significant value to the Company Board. Mr. de Balman currently serves as Executive Partner at Bridge Growth Partners, a private equity firm focusing on technology and financial services companies, and previously served as Co-Chairman of Bregal Investments LP, a private equity investing firm, from 2002 to 2012. He is also currently on the Board of Directors of ESI Group, a virtual prototyping software company.

Laurie Brlas. Ms. Brlas has served on the Exelon Board since 2018. She has proven leadership skills derived from her significant experience as an executive leader at global, capital-intensive companies, and operations and finance experience in the natural resources industry in addition to her background in financial and governance matters that will bring valuable insights to the Company Board. Ms. Brlas served as Executive Vice President and Chief Financial Officer of Newmont Mining Corporation, a global mining company, from 2013 to 2016. Prior to that, she served in multiple senior positions between 2006 and 2013, ultimately as Executive Vice President and President, Global Operations, with Cleveland-Cliffs, Inc., a company specializing in the mining, benefication and pelletizing of iron ore. Ms. Brlas currently serves on the Boards of Directors of Albemarle Corporation (since 2017), Graphic Packaging Holding Company (since 2019) and Autoliv, Inc. (since 2020). She previously served on the Boards of Directors of Calpine Corporation (2016 to 2018) and Perrigo Company plc (2003 to 2019).

Robert Lawless. Mr. Lawless has served on the Exelon Board since 2012. He has deep executive leadership, strategic planning, and corporate governance experience, as well as industry experience as a former director of Constellation Energy Group prior to its merger with Exelon in 2012, and will provide the Company Board with critical perspectives on governance and other public company issues. Mr. Lawless served in numerous senior level positions over a more than thirty year career with McCormick & Company, Inc., a global food manufacturing company, including as President from 1996 to 2006, as Chief Executive Officer from 1997 to 2008, and as Chairman from 1997 until 2009.

Admiral John Richardson. Admiral Richardson has served on the Exelon Board of Directors since 2019. His experience leading the U.S. Navy as well as his expertise in nuclear oversight and operational excellence will bring invaluable knowledge to our Board. Admiral Richardson served in various senior positions during his thirty-seven year career with the U.S. Navy, including as Chief of Naval Operations from 2015 to 2019, Director of Naval Reactors, commander of U.S. Submarine Forces, and Director of Strategy and Policy at the U.S. Joint Forces Command. He currently serves as a director of The Boeing Company (since 2019) and BWX Technologies, Inc. (since 2020). Admiral Richardson also currently serves as a director of Sparkcognition Government Systems, a developer of A.I. solutions for multiple industries including energy, defense and finance, and of the Center for New American Security, a bipartisan think tank focused on national security, including issues around energy and geopolitics.

We are currently in the process of evaluating additional candidates for the Company's Board and expect that, as of the distribution date, the Board will consist of nine members, of whom eight will meet applicable SEC and Marketplace Rules' independence requirements. Biographical information concerning each additional member will be included either in an amendment to this information statement or, if after the effectiveness of this information statement, on a Current Report on Form 8-K.

Our Corporate Governance

Our corporate governance will be structured in a manner that we believe will align our interests with those of our shareholders.

Following the separation, we anticipate our corporate governance will include the following notable features:

Board Diversity. Our Corporate Governance Committee is responsible for reviewing with the Board of Directors, on an annual basis, the appropriate characteristics, skills and experience required for the Board as a whole. In evaluating and recommending the suitability of candidates (both new candidates and current members) for election, the following factors will be taken into account:

- personal and professional integrity, ethics and values;
- experience in corporate management, such as serving as an officer or former officer of a publicly held company;
- experience as a board member or executive officer of another publicly held company;
- strong finance experience;
- expertise and experience in substantive matters pertaining to our business;
- diversity of background and perspective, including with respect to age, gender, race, place of residence and specialized experience;
- experience relevant to our business industry and with relevant social policy concerns; and
- relevant academic expertise or other proficiency in an area of our business operations.

Currently, our board evaluates each individual in the context of the Board of Directors as a whole, with the objective of assembling a group that can best maximize the success of the business and represent shareholder interests through the exercise of sound judgment using its diversity of experience in these various areas.

Composition of the Board of Directors Following the Separation

Upon completion of the separation, our amended and restated articles of incorporation and amended and restated bylaws will provide that our Board of Directors may consist of no less than five and no more than fifteen directors. The number of directors on our Board of Directors will be fixed exclusively by our Board of Directors, subject to the minimum and maximum number permitted by our amended and restated articles of incorporation and bylaws. We expect our Board of Directors to initially comprise nine members, eight of whom we expect will qualify as “independent” under the Nasdaq Stock Market Rules (the “*Marketplace Rules*”).

There will be no cumulative voting in the election of directors, and a director will be elected by receiving a majority of votes cast in uncontested elections and by a plurality of the votes cast in any contested election of directors.

Committees of the Board of Directors

Following the separation, our Board of Directors will have four standing committees, an Audit Committee, a Compensation and Leadership Development Committee, a Corporate Governance Committee, and a Nuclear Oversight Committee, each of which will have the composition and responsibilities described below. The members of the Audit, Compensation and Leadership Development, and the Corporate Governance Committees will satisfy the applicable independence standards of the SEC and the transition periods provided under the rules and regulations of the Marketplace Rules. The charter of each such standing committee will be posted on our website in connection with the separation. Our Board may also establish any other committees that it deems necessary or desirable from time to time. Committee memberships may be changed subject to the discretion of our Board.

Audit Committee

Upon completion of the separation, we expect our Audit Committee will consist of at least three members. The members and chair are expected to be appointed shortly following the distribution. It will function pursuant to a written charter adopted by the Board of Directors. The Audit Committee’s responsibilities will include, among other things:

- Assists the Board of Directors in the oversight and review of the quality and integrity of the Company’s financial statements and internal controls over financial reporting
- Appoints, retains and oversees the independent auditor and evaluates its qualifications, performance, independence and fees
- Oversees the Company’s internal audit function
- Reviews the processes by which the Company assesses and manages enterprise risk
- Oversees compliance with the Company’s Code of Business Conduct, and the process for the receipt and responses to complaints regarding accounting, internal controls, ethics or audit matters

The responsibilities of our Audit Committee will be more fully described in our Audit Committee charter. Our Board of Directors is expected to determine that each of the committee’s members satisfy the applicable independence and other requirements of the Marketplace Rules and the SEC for audit committees and that at least one will qualify as an “audit committee financial expert” as defined under applicable SEC rules and regulations. Laurie Brlas is expected to serve as a member of the Audit Committee and will serve as an “audit committee financial expert” and is independent, as defined under applicable SEC rules and regulations.

Compensation and Leadership Development Committee

Upon completion of the separation, we expect our Compensation and Leadership Development Committee will consist of at least three members. The members and chair are expected to be appointed shortly following the distribution. It will function pursuant to a written charter adopted by the Board of Directors. The Compensation and Leadership Development Committee's responsibilities will include, among other things:

- Assists the Board of Directors in establishing performance criteria, evaluation, and compensation for CEO
- Approves executive compensation program design for executive officers, other than the CEO
- Monitors and reviews leadership and succession information for executive roles
- Retains the Committee's independent compensation consultant
- Reviews Compensation Discussion and Analysis and prepares Compensation Committee Report for proxy statements

The responsibilities of our Compensation and Leadership Development Committee, and its procedures for the consideration and determination of executive compensation, will be more fully described in our Compensation and Leadership Development Committee charter. Our Board of Directors is expected to determine that each of the committee's members satisfy the applicable independence and other requirements of the Marketplace Rules, the SEC and the IRS for compensation committee members.

Corporate Governance Committee

Upon completion of the separation, we expect our Corporate Governance Committee will consist of at least three members. The members and chair are expected to be appointed shortly following the distribution. It will function pursuant to a written charter adopted by the Board of Directors. The Corporate Governance Committee's responsibilities will include, among other things:

- Identifies and recommends qualified candidates for election by the Board of Directors and shareholders and oversees the Board and committee structure and compensation
- Recommends Corporate Governance Guidelines and advises on corporate governance issues including evaluation processes for the Board, its committees, and directors and the CEO
- Oversees the Company's environmental strategies, including climate change and sustainability policies
- Reviews the Company's director compensation program and retains an independent compensation consultant
- Has authority to retain an independent search firm to identify candidates for a director

The responsibilities of our Corporate Governance Committee and the process for identifying and evaluating director nominees (including nominees recommended by shareholders) will be more fully described in our Corporate Governance Committee charter. Our Board of Directors is expected to determine that each of the committee's members satisfy the applicable independence and other requirements of the Marketplace Rules and the SEC for Corporate Governance Committee members.

Nuclear Oversight Committee

Upon completion of the separation, we expect to form a Nuclear Oversight Committee, the members and chair to be appointed shortly following the distribution. It will function pursuant to a written charter adopted by the Board of Directors. The Nuclear Oversight Committee's responsibilities will include, among other things:

- Oversees the safe and reliable operation of the Company's nuclear generating facilities with a principal focus on nuclear safety

- Oversees management and operations of the Company's nuclear generating facilities and the overall organizational effectiveness of nuclear generating station operations
- Oversees compliance with policies and procedures to manage and mitigate risks associated with the security and integrity of the Company's nuclear generation assets
- Reviews environmental, health and safety issues relating to nuclear generating facilities

The responsibilities of our Nuclear Oversight Committee, which are anticipated to be substantially the same as the responsibilities of Exelon's Generation Oversight Committee, will be more fully described in our Nuclear Oversight Committee charter.

Director Independence

We expect that our Board of Directors, upon recommendation of our Corporate Governance Committee, will formally determine the independence of our directors following the separation. We expect a majority of the directors will be independent and that our Board will determine that the following directors are independent: Ms. Brlas and Messrs. De Balmann, Lawless and Richardson. We expect our Board will determine the independence of directors annually based on a review by the Corporate Governance Committee. In determining whether a director is independent, we expect our Board will determine whether each director meets the objective standards for independence set forth in the Marketplace Rules.

Meetings of Independent Directors

We expect that our independent directors will meet regularly in executive session.

Attendance at Annual Meeting of Shareholders

Although we do not expect to have a formal policy regarding attendance by members of our Board of Directors at our annual meeting of shareholders, directors will be encouraged to attend and expect that at least a majority of directors will attend the annual meeting.

Shareholder Communication

We expect our Board of Directors will adopt a policy that will permit shareholders and other interested parties to communicate directly with the Board, any committee of our Board, or any individual director.

Risk Oversight

Our Board of Directors will rely on each of its committees to help oversee the risk management responsibilities relating to the functions performed by such committees. Our Audit Committee will periodically discuss with management our major financial risk exposures and the steps management has taken to monitor and control such exposures, including our risk assessment and risk management policies. Our Compensation and Leadership Development Committee will help the Board to identify our exposure to any risks potentially created by our compensation programs and practices. Our Corporate Governance Committee will oversee risks relating to our policies and assist the Board and management in promoting an organizational culture that encourages robust governance practices and oversight. And our Nuclear Oversight Committee will assist the Board in overseeing compliance with policies and procedures to manage and mitigate risks associated with the security and integrity of generating assets. Each of these committees will be required to make regular reports of its actions and any recommendations to the Board of Directors, including recommendations to assist the Board with its overall risk oversight function.

Compensation Committee Interlocks and Insider Participation

We do not expect any of members of our Compensation and Leadership Development Committee will have at any time been one of our officers or employees or have any relationships with us of the type that is required to be disclosed under Item 404 of Regulation S-K. We also expect that none of our executive officers will have served at any time as a member of the Board of Directors, compensation committee or other board committee performing equivalent functions of any entity that has one or more executive officers serving as one of our directors or on our Compensation and Leadership Development Committee.

Code of Conduct and Ethics

Prior to the completion of the separation, our Board of Directors will adopt a code of conduct and ethics (the "*Code of Ethics*") that will apply to all of our directors, officers and employees, including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. The Code of Ethics will be available upon written request to our corporate secretary or on our website, which we currently intend to make available at following the completion of separation. If we amend or grant any waiver from a provision of our Code of Ethics that applies to our executive officers, we will publicly disclose such amendment or waiver on our website and as required by applicable law. The information contained on, or accessible from, our website is not part of this information statement by reference or otherwise.

EXECUTIVE AND DIRECTOR COMPENSATION

Compensation Discussion & Analysis

The Company is currently a wholly owned subsidiary (which, prior to the separation, will own Generation and its subsidiaries) of Exelon Corporation and its compensation committee has not yet been formed. All decisions regarding 2020 compensation of Generation and its subsidiaries' named executive officers were made by the Compensation and Leadership Development Committee of the Exelon board of directors (referred to in this section as the "*Exelon Compensation Committee*") if the executive previously served as an executive officer of Exelon, or otherwise by Exelon management. After the distribution, the executive compensation programs, policies and practices for the Company's executive officers will be subject to the review and approval of the Compensation Committee of the Company board (the "*Company Compensation Committee*").

For purposes of this Compensation Discussion and Analysis and the following executive compensation tables, the individuals referred to as the "named executive officers" ("*NEOs*") are Generation and its subsidiaries' principal executive officer, principal financial officer and the three most highly compensated executive officers of Generation and its subsidiaries' based on 2020 compensation. The compensation discussed in this section refers to legacy Exelon compensation plans.

The individuals determined to be our NEOS based on 2020 compensation are listed below. The information reflects positions and compensation while we were held by Exelon and does not reflect the individuals who may be identified as NEOs by us in the future.

CHRISTOPHER CRANE[(a)]	President and Chief Executive Officer, Exelon
KENNETH W. CORNEW[(a)]	*(Former)* President and Chief Executive Officer, Generation
BRYAN WRIGHT	Senior Vice President and Chief Financial Officer, Generation
MICHAEL PACILIO[(b)]	*(Former)* Executive Vice President and Chief Operating Officer, Generation
BRYAN HANSON[(c)]	Executive Vice President, Chief Generation Officer, Generation
JAMES MCHUGH	Chief Executive Officer, Constellation business unit

(a) Mr. Crane was named principal executive officer of Generation effective October 21, 2020. Mr. Cornew served as Senior Executive Vice President and Chief Commercial Officer, Exelon; President and Chief Executive Officer, Generation through his departure on March 31, 2021.

(b) Mr. Pacilio held the role of Executive Vice President and Chief Operating Officer of Generation until his retirement on January 15, 2021.

(c) Mr. Hanson held the title of Senior Vice President Generation; President & Chief Nuclear Officer Generation Nuclear until his promotion to Executive Vice President, Chief Generation Officer effective September 9, 2020.

All NEOs have compensation that is structured in part like Exelon's executive officers, based in part on overall Exelon goals as well as goals of Generation and its subsidiaries. The Company NEOs will participate in compensation programs designed to align their interests with the Company's customers and other stakeholders.

Mr. Pacilio departed Generation on January 15, 2021 and Mr. Cornew departed Generation as of March 31, 2021. Additional details about their separations are included on the termination tables shown below.

For both the CEO and NEOs, a significant portion of their compensation is tied to the achievement of short- and long-term financial and operational goals and is paid in the form of Exelon equity with all components except for salary being "at-risk."

CEO		All NEOs	
Base Salary	**9.1%**	Base Salary	**22.5%**
Annual Incentive Plan (AIP)	**13.2%**	Annual Incentive Plan (AIP)	**17.9%**
Long-Term Incentive Plan (LTIP)	**77.6%**	Long-Term Incentive Plan (LTIP)	**59.6%**
Pay at Risk (AIP + LTIP)	***90.9%***	*Pay at Risk (AIP + LTIP)*	***77.5%***

Executive Compensation Program Philosophy and Objectives

The goal of our executive compensation program is to retain and reward leaders who create long-term value by delivering on objectives that support strategic business objectives. Each element of total direct compensation is based on market data, the executive's competencies and skills, scope of responsibilities, experience and performance, retention, succession planning and organizational structure of the business.

2020 Compensation Program Structure

The 2020 compensation program is summarized below. Primary compensation elements include fixed and variable components.

Pay Element	Form	Shareholder Alignment
Salary	Cash	a) Fixed income at competitive, market-based levels attracts and retains top talent.
Annual Incentive Plans ("*AIP*")	Cash	b) Motivates executives to achieve key annual financial and operational goals that reflect commitment to superior operations and supporting our customers and communities
Long-Term Incentive Plan ("*LTIP*")	Performance Shares (**67%** of LTIP)	c) Drives executive focus on long-term goals supporting utility growth, financial results, and capital stewardship d) Rewards relative achievement of financial goals and stock price compared to utility peers ("*UTY*") over three-year period
	Restricted Stock (**33%** of LTIP)	e) Aligns the interests of executives with stockholders by capping payouts if absolute TSR is negative for the prior 36-month period f) Balances LTI portfolio providing executive with market competitive time-based award.

2020 Base Salaries

Base salaries for 2020 were determined by the Exelon Compensation Committee for Messrs. Crane and Cornew. The Exelon Compensation Committee also set the base salary for Mr. Hanson following his promotion in September 2020. When evaluating whether to make any adjustments, the Exelon Compensation Committee considers a number of factors including the outcome of the annual merit review, results of the annual market assessment of executive compensation provided by Exelon Compensation Committee's independent compensation consultant, the need to retain experienced executives, individual performance, scope of responsibility, leadership skills and values, current compensation, internal equity, and legacy matters.

Base salaries for the remaining Generation and subsidiary NEOs are set by the Exelon CEO. Base salaries may be adjusted (1) as part of the annual merit review or (2) based on a promotion or significant change in job scope. The Exelon CEO considers the results of the annual market assessment in addition to the following factors when contemplating a merit review: individual performance, scope of responsibility, leadership skills and values, current compensation, internal equity, and legacy matters.

In January 2020 as part of its annual merit review, the Exelon Compensation Committee recommended Mr. Crane's base salary be held flat based on the annual market assessment conducted by the independent compensation consultant, Meridian Compensation Partners, LLC. At the same time, the Exelon Compensation Committee approved a 2.5% increase in base salary for Mr. Cornew. For each other NEO, Mr. Crane approved a 2.5% increase in base salary. Merit increases were effective March 1, 2020.

In September 2020, Mr. Hanson was promoted to Executive Vice President and Chief Generation Officer and his total direct compensation was increased accordingly.

2020 Annual Incentive Plan (AIP) Overview and Goal Setting

AIP metrics are linked to business goals and strategic focus areas. The goal-setting process employs a multi-layer approach and analysis that incorporates a blend of objective and subjective business considerations and other analytical methods to ensure that the goals are sufficiently rigorous. Such considerations include:

Recent History — Goals generally reflect a logical progression of results from the recent past

Relative Performance — Performance is evaluated against a relevant group of Generation and its subsidiaries' peers

Strategic Aspirations — Near- and intermediate-term goals follow a trend line consistent with long-term aspirations

Shareholder Expectations — Goals are aligned with externally communicated financial guidance and shareholder expectations

Sustainable Sharing — Earned awards reflect a balanced degree of shared benefits between shareholders and participants

The following process was used to determine 2020 AIP awards for each NEO:

1) **Set AIP Target** — Expressed as percentage of base salary. Mr. Crane's annual incentive target was 145% and for the other NEOs, the annual incentive targets ranged from 50%-100%.

2) **Determine Performance Factor** — Based on various financial and operating metrics.

3) **Determine Individual Performance Multiplier (IPM) —** IPM measures individual performance and ranged from 50% to 110% (target of 100%). Messrs. Crane, Cornew, and Hanson were not eligible for an IPM. For the other NEOs, the IPMs were approved by Mr. Crane up to a maximum of 110%.

4) **Apply Final Multiplier —** Multiply the target award by the performance factor and then multiply the outcome by the IPM. Awards could range from 0% to 200% of target (target of 100%).

The following tables detail the 2020 threshold, target, and distinguished, i.e., maximum, performance goals, and the results achieved for the AIP. The Exelon Compensation Committee selected the performance metrics below as they align with the long-term business strategy.

Messrs. Crane, Cornew, and Hanson (for Mr. Hanson, for September 9 – December 31, 2020 only):

2020 Goals	Threshold	Target	Distinguished	2020 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
Exelon Adjusted (non-GAAP) Operating EPS(1)*	$ 2.97	$3.19 – $3.22	$ 3.57	**$ 3.08**	75.00%	52.5%
CAIDI	92	85	80	**80**	200.00%	15.0%
SAIFI	0.82	0.69	0.56	**0.59**	176.92%	13.27%
Fleetwide Capacity Factor	91.954%	93.954%	95.847%	**94.381%**	122.56%	9.19%
Dispatch Match	94.8%	97.4%	99.4%	**98.4%**	150.00%	11.25%
					Payout:	**101.21%**

Mr. Hanson (January 1 – September 8, 2020):

2020 Goals	Threshold	Target	Distinguished	2020 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
Exelon Adjusted (non-GAAP) Operating EPS(1)*	$ 2.97	$3.19 – $3.22	$ 3.57	**$ 3.08**	75.00%	37.5%
Generation Operating Net Income ($M)*	$1,124.0	$ 1,208.6	$1,353.6	**$1,410.3**	200.00%	50.00%
Fleetwide Capacity Factor %	91.954%	93.954%	95.847%	**94.381%**	122.56%	30.64%
					Payout:	**118.14%**

Mr. Wright

2020 Goals	Threshold	Target	Distinguished	2020 Actual Results	Unadjusted Payout as a % of Target	Board Limiter Application
Average of Nuclear, Power, and Constellation KPIs	50%	100%	200%	**131.86%**	131.86%	YES
					Payout:	**130.00%**

Mr. Pacilio

2020 Goals	Threshold	Target	Distinguished	2020 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
Exelon Adjusted (non-GAAP) Operating EPS(1)*	$ 2.97	$3.19 – $3.22	$ 3.57	**$ 3.08**	75.00%	37.5%
Generation Operating Net Income ($M)*	$1,124.0	$ 1,208.6	$1,353.6	**$1,410.3**	200.00%	50.00%
Average of Nuclear and Power KPIs	50%	100%	200%	**141.1%**	141.1%	35.3%
					Payout:	**122.78%**

Mr. McHugh

2020 Goals	Threshold	Target	Distinguished	2020 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
Exelon Adjusted (non-GAAP) Operating EPS[(1)]*	$ 2.97	$3.19 – $3.22	$ 3.57	**$ 3.08**	75.00%	37.5%
Generation Operating Net Income ($M)*	$1,124.0	$ 1,208.6	$1,353.6	**$1,410.3**	200.00%	50.0%
Constellation Adj EBIT*	$5,987.2	$ 6,507.8	$7,288.8	**$6,437.4**	93.24%	23.3%
					Payout:	**110.81%**

(1) Exelon's 2020 Adjusted EPS was $3.22. However, for purposes of determining the 2020 AIP payouts for Exelon executives, $3.08 was used, which excludes the impact of $0.14 of unrealized gain from equity investments.

* Exelon reports its financial results in accordance with accounting principles generally accepted in the United States (GAAP) and supplements its reporting with certain non-GAAP financial measures, including adjusted (non-GAAP) operating earnings per share, earned ROE, and FFO/Debt to enhance investors' understanding of Exelon's performance. Our method of calculating adjusted (non-GAAP) operating earnings and operating ROE may not be comparable to other companies' presentations.

Adjusted (non-GAAP) operating earnings per share exclude certain costs, expenses, gains and losses and other specified items, including mark-to-market adjustments from economic hedging activities, unrealized gains and losses from nuclear decommissioning trust fund investments, certain costs associated with plant retirements and divestitures, costs related to cost management programs, and other items as set forth in the table below reconciling adjusted (non-GAAP) operating earnings from GAAP earnings, which is the most directly comparable GAAP measure. Management uses adjusted (non-GAAP) operating earnings as one of the primary indicators to evaluate performance, allocate resources, set incentive compensation targets and plan and forecast future periods. We believe the measure enhances an investor's overall understanding of period over period financial results and provides an indication of Exelon's baseline operating performance by excluding items that are considered by management to not be directly related to the ongoing operations of the business.

The table below reconciles reported GAAP Earnings per share to adjusted (non-GAAP) operating earnings per share for 2020 (amounts may not add due to rounding).

2020 GAAP Earnings (Loss) Per Share	2.01
Adjustments:	
Mark-to-market impact of economic hedging activities	(0.22)
Unrealized gains related to nuclear decommissioning trust (NDT) funds	(0.26)
Asset impairments	0.41
Plant retirements and divestitures	0.74
Cost management program	0.05
Change in environmental liabilities	0.02
COVID-19 direct costs	0.05
Deferred Prosecution Agreement Payments	0.20
Asset retirement obligation	0.05
Income tax-related adjustments	0.07
Noncontrolling interests	0.11
2020 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	3.22

Earned ROE is calculated using adjusted (non-GAAP) operating earnings, reflecting all lines of business for the utility businesses (electric distribution, gas distribution, transmission), divided by average shareholder's equity over the year. Management uses operating ROE as a measurement of the actual performance of the company's utility business.

FFO/Debt is a coverage ratio that compares funds from operations to total debt and is a key ratio analyzed by the credit rating agencies in determining Exelon's credit rating. An investment grade rating is critical as it increases the ability to participate in commercial business opportunities, lowers collateral requirements, creates reliable and cost-efficient access to capital markets and increases business and financial flexibility. The ratio is calculated following S&P's current methodology. The most directly comparable GAAP measure to FFO is GAAP Cash Flow from Operations and the most directly comparable GAAP measure to Debt is Long-Term Debt plus Short-Term Borrowings. Management uses FFO/Debt to evaluate financial risk by measuring the company's ability to service debt using cash from operations. We believe the measure enhances an investor's overall understanding of the creditworthiness of Exelon's operating companies.

Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available; therefore, management is unable to reconcile these measures.

The following table shows how the formula was applied and the actual amounts awarded. The Exelon Compensation Committee applied negative discretion to limit Mr. Wright's payout to 130% of target.

NEO	AIP Target (%)	AIP Target ($)	Formulaic Performance Factor (Note 1)	Individual Performance Multiplier (IPM)	Actual Award ($)
Crane	145%	1,874,850	101.21%	100%	1,897,536
Cornew	100%	951,541	101.21%	100%	963,055
Wright	50%	226,504	130.00%	105%	309,178
Pacilio	85%	742,050	122.78%	110%	1,002,198
Hanson	80%	560,000	101.21%	100%	594,728
McHugh	80%	525,600	110.81%	105%	611,538

Mr. Hanson's AIP award was prorated based on the performance goals prior to his promotion in September 2020 (performance factor of 118.14%) and the performance goals after his promotion (101.21%).

Long-Term Incentive Plan (LTIP) Overview & Goal Setting Process

The Exelon Compensation Committee grants long-term equity incentive awards annually at its January or February meeting. When the total target equity incentive award is determined, the value is split between RSUs (33%) and performance shares (67%).

Restricted Stock Units ("*RSUs*"). RSUs granted to NEOs vest ratably over a three-year period. RSUs receive dividend equivalents that are reinvested as additional RSUs and remain subject to the same vesting conditions as the underlying RSUs. RSUs are not subject to any performance metrics.

Performance Shares. Performance shares granted to NEOs in January 2020 are earned based on performance achieved for the three-year period ending on December 31, 2022. The performance metrics underlying the 2020-2022 performance share awards are listed below. These are the same performance metrics underlying the performance shares granted for the 2018-2020 and 2019-2021 performance cycles.

Performance share metrics:	Why it is Important
Utility Earned ROE* (33.3%) Average utility ROE weighted by year-end rate base. Earned ROE is calculated using adjusted (non-GAAP) operating earnings, reflecting all lines of business for the utility businesses (electric	Measure of value created by utility businesses. Aligned with our strategy to invest in our utilities where we can earn an appropriate return.

Performance share metrics:	Why it is Important
distribution, gas distribution, transmission), divided by average shareholder's equity over the year.	
Utility Net Income (33.3%)	
Aggregate utility adjusted (non-GAAP) operating earnings, including Exelon hold-co net operating income (loss)	Measures financial performance of the Utilities. Aligned with our strategy to grow our regulated utility business.
Exelon FFO/Debt* (33.4%)	
Funds from operations to total debt ratio. The ratio is calculated following S&P's current methodology. Management uses FFO/Debt to evaluate financial risk by measuring ability to service debt using cash from operations	Key ratio for determining our credit rating and thereby our access to capital. Aligned with our strategy to generate free cash and reduce debt.

* See definitions of Non-GAAP measures on pages 160 to 161.

Setting Performance Share Targets. Performance share targets are set based on external commitments and/or probability modeling. The performance scale range for the Utility ROE and Utility Net Income metrics was based on the following probability levels of achievement: 95% for threshold and 5% for distinguished with the target aligned with projected performance. The target for the Exelon FFO/Debt metric is aligned with the expectations of credit rating agencies.

Actual Targets Disclosed After Each Cycle. Actual targets used in our performance share cycles are not disclosed until each cycle is completed to safeguard the confidentiality of our long-term outlook on projected performance. This policy supports the propriety of our long-standing disclosure practices to only issue annual performance guidance as part of our financial disclosure policies.

Performance Share Awards Subject to TSR Modifier and Cap. Performance share awards are subject to a total shareholder return ("*TSR*") modifier that compares Exelon's performance relative to the performance of the UTY index on a point by point basis. Performance share awards are also subject to a TSR cap that will limit payouts at target if TSR is negative for the prior 36-month period.

The Exelon Compensation Committee used the following process to determine performance share targets and awards:

(1) **Establish Performance Share Award Target** — Targets are set in January/February of the first year of the performance cycle.

(2) **Determine Performance Multiplier** — The Performance Multiplier is based on performance achieved over the three-year cycle. Performance can range from 0% to 150% of target (target of 100%).

(3) **Determine TSR Modifier** — Calculated by subtracting the TSR of the UTY over the three-year performance period from Exelon's TSR for the same three-year period.

(4) **Calculate Final Multiplier —** Calculated by multiplying the Performance Multiplier by (100% + TSR Modifier). This value is the Final Multiplier.

(5) **Apply Final Multiplier & TSR Cap (if applicable)** — Apply the Final Multiplier to determine the number of shares issued. If Exelon's absolute TSR for the final 12-month of the performance period is negative, payout will be capped at 100%. (Beginning with the 2020-2022 cycle, the TSR cap will apply if TSR is negative for the prior 36-month period.) Awards can range from 0% to 200% of target (target of 100%) after application of the TSR modifier.

2018 – 2020 Performance and Performance Share Payout Determinations

The following table details the 2018 – 2020 threshold, target, and distinguished performance goals, and the results achieved. The performance multiplier for the 2018 – 2020 Performance Share awards was calculated to be **76.01%** of target, based on the following:

Performance Share Scorecard

	Metric Weighting	Threshold (50%)	75%	Target (100%)	125%	Distinguished (150%)	Actual Score	Actual Award v. Metric Weighting
Utility Earned ROE*	33.3%	8.0%	9.3%			10.7%	**8.7%**	25.62%
Utility Net Income	33.3%	$1,587	$1,880			$2,185	**$1,740**	25.34%
Exelon FFO/Debt*	33.4%	≥16.0% and <17.0%	≥17.0% and <18.0%	≥18.0% and <22.0%	≥22.0% and <24.0%	≥24.0%	**17.8%**	25.05%
					Committee Approved Performance:			**76.01%**

The Utility Earned ROE* and Utility Net Income use interpolation between threshold, target, and distinguished levels of performance whereas the FFO/Debt* metric uses a "stair-step" approach with no interpolation between the performance levels.

* See definitions of Non-GAAP measures on pages 160 to 161.

Payout Determinations. The Exelon Compensation Committee approved a payout of 63.65%, based on 2018 – 2020 performance and the application of a TSR modifier of -16.26% based on 2018 – 2020 TSR performance relative to the UTY.

The following table shows how the formula was applied and the actual amounts awarded.

NEO	Target Shares		Performance Factor		Actual Award
Crane	176,541	x	63.65%	=	**112,368**
Cornew	51,020	x	63.65%	=	**32,474**
Wright	8,531	x	63.65%	=	**5,430**
Pacilio	36,927	x	63.65%	=	**23,504**
Hanson	25,346	x	63.65%	=	**16,133**
McHugh	27,547	x	63.65%	=	**17,534**

Performance Awards Settled in Common Stock and/or Cash. Pursuant to the terms of the long-term incentive program, all NEOs that have achieved 200% or more of their stock ownership targets receive performance share award payouts in cash. Other performance share participants who have not achieved 200% of their stock ownership targets receive payouts that are settled 50% in shares of Exelon common stock and 50% in cash.

Performance Share Goal Rigor

To ensure adequate rigor for the financial targets applicable to the 2020-2022 performance share cycle, we conducted statistical simulations to understand the level of difficulty of our payout range. We conducted a sensitivity analysis of reasonable value ranges for several internal and external variables that are significant drivers of performance, and we also examined historical levels of deviation of Generation and its subsidiaries' performance compared to plan.

2020 Target Compensation for Named Executive Officers

The table below lists the target value of the compensation elements for each NEO as of December 31, 2020.

NEO	Cash Compensation: Base ($)	Cash Compensation: AIP Target	Cash Compensation: Target Total Cash ($)	Long-Term Incentives: RSUs (33% of LTIP) ($)	Long-Term Incentives: Performance Shares (67% of LTIP) ($)	Long-Term Incentives: Target Total LTIP ($)	Target Total Direct Compensation ($)
Crane	1,293,000	145%	3,167,850	3,630,000	7,370,000	11,000,000	14,167,850
Cornew	951,541	100%	1,903,082	963,204	1,955,596	2,918,800	4,821,882
Wright	453,008	50%	679,512	161,040	326,960	488,000	1,167,512
Pacilio	873,000	85%	1,615,050	697,125	1,415,375	2,112,500	3,727,550
Hanson	700,000	80%	1,260,000	684,750	1,390,250	2,075,000	3,335,000
McHugh	657,000	80%	1,182,600	552,750	1,122,250	1,675,000	2,857,600

Shareholder Engagement

The Exelon Compensation Committee regularly reviews executive compensation, taking into consideration input received through regular and ongoing engagement with investors. Feedback is typically solicited throughout the year in connection with the annual meeting of shareholders and the Exelon Compensation Committee's review of the executive compensation program. The Chairs of Exelon's Compensation and Corporate Governance Committees participated in select investor discussions in 2020. Feedback from all discussions was shared with the appropriate board committee and/or the full board. Shareholders in general expressed their approval of the ongoing executive compensation program and did not request any significant changes during our engagement conversations.

2020 Compensation Decisions — Setting Target Total Direct Compensation ("*TDC*")

Setting Target TDC for Mr. Crane: The Exelon Compensation Committee is responsible for reviewing and recommending the Exelon CEO's target total direct compensation. The CEO's compensation is then approved by the independent members of the Exelon board. The Exelon Compensation Committee fulfills this responsibility by analyzing peer group compensation and performance data with its independent compensation consultant. The Committee also reviews the various elements of the CEO's compensation in the context of the target TDC, which includes base salary, annual and long-term incentive target opportunities.

Setting Target TDC for Messrs. Cornew, and Hanson: The Exelon Compensation Committee is also responsible for approving the executive compensation for each of Exelon's executive officers (including Messrs. Cornew and Hanson) by analyzing peer group compensation and performance data. Mr. Hanson's compensation was first included under the Committee's scope as of September 9, 2020 as a result of his promotion.

Setting Target TDC for the other NEOs: The Exelon CEO analyzes a variety of data to gauge market competitiveness, including peer group compensation and performance data provided by Exelon's independent compensation consultant. TDC can vary by named executive officer based on competencies and skills, scope of responsibilities, the executive's experience and performance, retention, succession planning and the organizational structure of the businesses (e.g., internal alignment and reporting relationships).

Role of the Compensation Consultant

As referenced earlier, the Exelon Compensation Committee retains Meridian Compensation Partners, LLC ("*Meridian*"), an independent compensation consultant, to support its duties and responsibilities. Meridian provides advice and counsel on executive and director compensation matters and provides information and advice regarding market trends, competitive compensation programs, and strategies including as described below:

- Market data for each senior executive position, including evaluating Exelon's compensation strategy and reviewing and confirming the peer group used to prepare the market data,
- An independent assessment of management recommendations for changes in the compensation structure,

- Assisting management to ensure Generation and its subsidiaries' executive compensation programs are designed and administered consistent with the Exelon Compensation Committee's requirements, and
- Ad hoc support on executive compensation matters and related governance trends.

Peer Groups Used for Benchmarking 2020 Executive Compensation

Exelon uses a blended peer group for assessing our executive compensation program that consists of two sub-groups: energy services peers and general industry peers because (1) there are not enough energy services peers with size, scale and complexity comparable to Exelon to create a robust energy services-only peer group, and (2) Exelon's market for attracting talent includes general industry peers, with key executives hired from several Fortune 100 companies. When selecting general industry peers, we look for capital asset-intensive companies with size, scale and complexity similar to Exelon, and we also consider the extent to which they may be subject to the effects of volatile commodity prices similar to Exelon's sensitivity to commodity price volatility. Exelon evaluates its peer group on an annual basis in July and adjusts for changes with our energy and general industry peers when needed.

Exelon's revenues are at the 64th percentile of the following blended peer group comprising 21 companies:

(1) *Energy Services (11 peer companies)*: American Electric Power Company, Inc.; Dominion Energy, Inc.; DTE Energy; Duke Energy Corporation; Edison International; Entergy Corporation; FirstEnergy Corporation; NextEra Energy, Inc.; Public Service Enterprise Group, Inc.; Sempra Energy; and The Southern Company.

(2) *General Industry (10 peer companies)*: 3M Company; Deere & Company; Delta Air Lines; General Dynamics Corporation; Honeywell International, Inc.; International Paper Company; Lockheed Martin; Marathon Petroleum Company; Northrop Grumman Corporation; and Valero Energy Corporation.

Because there is a correlation between the size of an organization and its compensation levels, market data is statistically adjusted using a regression analysis. This commonly applied technique allows for a more precise estimate of the market value of Generation and its subsidiaries given the size and scope of responsibility for Generation and its subsidiaries' executive roles. Each element of NEO compensation is then compared to these size-adjusted medians of the peer group.

In preparation for the separation, we are reviewing the peers to be used for benchmarking the assessment of 2022 compensation for named executive officers of the Company.

Stock Ownership

To strengthen the alignment of executive interests with those of Exelon's shareholders, officers of Generation and its subsidiaries are required to own certain amounts of Exelon common stock five years following his or her employment or promotion to a new position (six-times base salary for Mr. Crane; two to three times base salary for the other NEOs). As of the annual measurement date of September 30, 2020, all NEOs had exceeded 200% of their stock ownership guidelines. We expect to adopt a similar stock ownership policy for officers of the Company.

Prohibition on Hedging and Pledging of Common Stock; Other Trading Requirements

Exelon requires executive vice presidents and above who wish to sell Exelon common stock to do so only through the adoption of a stock trading plan meeting the requirements of SEC Rule 10b5-1(c). This requirement is designed to enable officers with the ability to diversify holdings in an orderly manner to meet personal financial plans. Our insider trading policy includes provisions that prohibit directors and employees (including officers) and certain of their related persons (including certain family members and entities which they own a significant interest) from engaging in short sales, put or call options, hedging transactions, pledging, or other derivative transactions involving Exelon stock. We expect to adopt a similar policy for officers of the Company.

Clawback Policy

The Exelon board of directors approved its current clawback policy in 2018. The policy provides broad discretionary ability to clawback incentive compensation when deemed appropriate. Under the policy, the Exelon board has sole discretion to recoup incentive compensation if it determines that (a) the incentive compensation was based on the achievement of financial or other results that were subsequently restated or corrected, (b) the incentive plan participant engaged in fraud or intentional misconduct that caused or contributed to the need for restatement or correction, (c) a lower incentive plan award would have been made to the participant based on the restated or corrected results, and (d) recoupment is not precluded by applicable law or employment agreements.

The Exelon board or Exelon Compensation Committee may also seek to recoup incentive compensation paid or payable to current or former incentive plan participants if, in its sole discretion, the Exelon board or Exelon Compensation Committee determines that (a) the current or former incentive plan participant breached a restrictive covenant or engaged or participated in misconduct or intentional or reckless acts or omissions or serious neglect of responsibilities that caused or contributed to a significant financial loss or serious reputational harm to Exelon or its subsidiaries regardless of whether a financial statement restatement or correction of incentive plan results was required, and (b) recoupment is not precluded by applicable law or employment agreements.

We expect to adopt clawback policies that are similar to those maintained by Exelon.

Risk Management Assessment of Compensation Policies and Practices

The Exelon Compensation Committee reviews Exelon's compensation policies and practices as they relate to the risk management practices and risk-taking incentives. The Exelon Compensation Committee partners with Generation's enterprise risk management group to assess and validate that the controls in place continued to mitigate incentive compensation risks.

Tax Consequences

Under Section 162(m) of the Internal Revenue Code (the Code), generally NEO compensation over $1 million for any year is not deductible for United States income tax purposes. The Compensation and Leadership Development Committee believes that it must maintain flexibility in its approach to executive compensation in order to structure a program that it considers to be the most effective in attracting, motivating and retaining the Company's key executives, and therefore, the deductibility of compensation is one of several factors considered when making executive compensation decisions.

Executive Compensation Tables

2020 Summary Compensation Table

Name	Year	Salary ($)	Bonus ($) (Note 1)	Stock Awards ($) (Note 2)	Non-Equity Incentive Plan Compensation ($) (Note 3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (Note 4)	All Other Compensation ($) (Note 5)	Total ($)
Christopher Crane President and CEO, Exelon	2020	1,293,000	—	11,000,013	1,897,536	757,754	214,500	15,162,803
Kenneth Cornew (Former) President and Chief Executive Officer, Generation	2020	947,189	—	2,918,828	963,055	299,794	338,335	5,467,201

Name	Year	Salary ($)	Bonus ($) (Note 1)	Stock Awards ($) (Note 2)	Non-Equity Incentive Plan Compensation ($) (Note 3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (Note 4)	All Other Compensation ($) (Note 5)	Total ($)
Bryan Wright Senior Vice President and Chief Financial Officer, Generation	2020	450,936	64,723	488,016	294,455	123,461	25,975	1,447,566
Michael Pacilio (Former) Executive Vice President and Chief Operating Officer, Generation	2020	869,067	91,109	2,112,544	911,089	870,150	67,338	4,921,297
Bryan Hanson Chief Generation Officer, Generation	2020	686,418	—	1,450,054	594,728	885,522	59,602	3,676,324
James McHugh Chief Executive Officer, Constellation business unit	2020	653,981	29,121	1,675,059	582,417	26,209	60,738	3,027,525

Notes to the Summary Compensation Table

(1) In recognition of their overall performance, certain NEOs received an individual performance multiplier (IPM) to their annual incentive payments or other special recognition awards. Messrs. Crane, Cornew and Hanson were not eligible for an IPM.

(2) The amounts shown in this column include the aggregate grant date fair value of restricted stock unit and performance share unit awards for the 2020-2022 performance period granted January 27, 2020. The grant date fair values of the stock awards have been computed in accordance with FASB ASC Topic 718 using the assumptions described in Note 21 of the Combined Notes to Consolidated Financial Statements included in Exelon’s 2020 Annual Report on Form 10-K. The 2020-2022 performance share award component of the stock award values depicted above are subject to performance conditions and the grant date fair value assumes the achievement of the target level of performance; however, values may be higher based on performance including the maximum total shareholder return multiplier as follows:

	Performance Share Award Value	
Name	At Target ($)	At Maximum ($)
Crane	7,370,008	14,740,016
Cornew	1,955,607	3,911,214
Wright	326,967	653,934
Pacilio	1,415,406	2,830,812
Hanson	971,540	1,943,080
McHugh	1,122,284	2,244,568

(3) The amounts shown in this column for 2020 represent payments made pursuant to the Annual Incentive Plan.

(4) The amounts shown in this column represent the change in the accumulated pension benefit for the NEOs from December 31, 2019 to December 31, 2020. None of the NEOs had above market earnings in a non-qualified deferred compensation account in 2020.

(5) All Other Compensation: The following table describes the incremental cost of other benefits provided in 2020 that are shown in this column.

All Other Compensation

Name	Perquisites ($) (Note 1)	Reimbursement for Income Taxes ($) (Note 2)	Exelon Contributions to Savings Plans ($) (Note 3)	Exelon Paid Term Life Insurance Premiums ($) (Note 4)	Total ($)
Crane	108,713	3,257	64,545	37,985	214,500
Cornew	271,930	17,363	45,290	3,752	338,335
Wright	7,500	—	14,150	4,325	25,975
Pacilio	19,340	375	43,056	4,567	67,338
Hanson	19,343	1,669	34,476	4,114	59,602
McHugh	24,382	428	31,552	4,376	60,738

Notes to All Other Compensation Table

(1) Amounts reported for personal benefits provided to NEOs include: (1) transportation related benefits (including corporate aircraft, parking, spousal and family travel); and (2) other benefits (including personal financial planning, company gifts, and matching charitable contributions).

a. Amounts reported for the personal use of corporate aircraft are based on the aggregate incremental cost to Exelon and are calculated using the hourly incremental cost for flight services, including federal excise taxes, fuel charges, and domestic segment fees. Exelon's board-approved policy on corporate aircraft usage includes spousal/domestic partner and other family member usage when appropriate. Amounts reported in this column for Mr. Crane include $81,873 for personal use of corporate aircraft.

b. Amounts include the value received by Mr. Cornew due to Generation's agreement to have its relocation vendor purchase at an appraised value the Baltimore residence purchased by Mr. Cornew in connection with his relocation to Baltimore as Chief Executive Officer of Constellation business unit. The value of the benefit included is $216,640, based on a determination of the difference between the average of two appraisals to be received and the price Mr. Cornew paid for the home in 2012 plus qualified capital improvements as provided for under the executive relocation program's standard terms.

c. Limited personal financial planning benefits valued at $16,840 for each executive are provided with usage values imputed as additional taxable income. Executive officers may request matching gifts to qualified charitable organizations in amounts up to $10,000 and up to $15,000 for Mr. Cornew under the Constellation Energy Group, Inc. legacy policy.

(2) Exelon provides reimbursements of tax obligations incurred when: employees are required to work outside their state of home residence and encounter double taxation in states and localities where tax credits are not permitted in home state tax filings; business-related spousal travel involves personal benefits and income is imputed to the employee and for required relocation and housing/living expenses incurred in compliance with regulatory requirements.

(3) The amounts represent the respective corporate matching contributions to the NEOs' accounts. Each of the named executive officers participated in the 401(k) Plan and the Deferred Compensation Plan. Mr. Wright does not participate in the Deferred Compensation Plan.

(4) Exelon provides basic term life insurance, accidental death and disability insurance, and long-term disability insurance to all employees, including NEOs. The values shown in this column include the premiums paid during 2020 for additional term life insurance policies for the NEOs and for additional supplemental accidental death and dismemberment insurance and long-term disability over and above the basic coverage provided to all employees.

2020 Grants of Plan-Based Awards

Name	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (Note 1) Threshold ($)	Plan ($)	Maximum ($)	Estimated Possible Payouts Under Equity Incentive Plan Awards (Note 2) Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares or Units (#) (Note 3)	Grant Date Fair Value of Stock and Option Awards ($) (Note 4)
Crane	1/27/20	70,307	1,874,850	3,749,700					
	1/27/20				25,991	155,913	311,826		7,370,008
	1/27/20							76,793	3,630,005
Cornew	1/27/20	35,683	951,541	1,903,082					
	1/27/20				6,897	41,371	82,742		1,955,607
	1/27/20							20,377	963,221
Wright	1/27/20	56,626	226,504	453,008					
	1/27/20				1,153	6,917	13,834		326,967
	1/27/20							3,407	161,049
Pacilio	1/27/20	46,378	742,050	1,484,100					
	1/27/20				4,991	29,943	59,886		1,415,406
	1/27/20							14,748	697,138
Hanson	1/27/20	21,000	560,000	1,120,000					
	1/27/20				3,426	20,553	41,106		971,540
	1/27/20							10,123	478,514
McHugh	1/27/20	32,850	525,600	1,051,200					
	1/27/20				3,958	23,742	47,484		1,122,284
	1/27/20							11,694	552,775

Notes to Grants of Plan-Based Awards Table

(1) All NEOs have annual incentive plan target opportunities based on a fixed percentage of base salaries. Under the terms of the AIP, threshold performance earns 50% of the respective target, while performance at plan earns 100% of the respective target and the maximum payout is capped at 200% of target.

a. For Messrs. Crane, Cornew, and Hanson, the possible payout at threshold for AIP was calculated at 3.75% of target based on a threshold payout of 50% for the lowest weighted metric of 7.5%.

b. For Mr. Wright, the possible payout at threshold for AIP was calculated at 25% of target based on a threshold payout of 50% and an individual performance multiplier of 50%.

c. For Messrs. Pacilio and McHugh, the possible payout at threshold for AIP was calculated at 6.25% of target based on threshold payout of 50% for the lowest weighted metric and an individual performance multiplier of 50%.

For additional information about the terms of these programs, see “Compensation Discussion and Analysis” above.

(2) NEOs have a long-term performance share unit target opportunity that is a fixed number of performance share units commensurate with the officer’s position. The possible payout at threshold for performance share unit awards was calculated at 16.67% of target. The possible maximum payout for performance share units was calculated at 150% of target, with an uncapped total shareholder return multiplier, capped at 200% of target. For additional information about the terms

of these programs, see Compensation Discussion and Analysis and the footnotes to the Summary Compensation Table above.

(3) This column shows restricted stock unit awards made during the year. The vesting dates of the awards are provided in footnote 2 to the Outstanding Equity Table below.

(4) This column shows the grant date fair value, calculated in accordance with FASB ASC Topic 718, of the performance share unit awards and restricted stock units granted to each NEO during 2020. Fair value of performance share unit awards granted on January 27, 2020 are based on an estimated payout of 100% of target.

2020 Outstanding Equity Awards at Year End

	Option Awards (Note 1)				Stock Awards			
Name	**Number of Securities Underlying Unexercised Options That Are Exercisable (#)**	**Number of Securities Underlying Unexercised Options That Are Not Exercisable (#)**	**Option Exercise or Base Price ($)**	**Option Expiration Date**	**Number of Shares or Units of Stock That Have Not Yet Vested (#) (Note 2)**	**Market Value of Shares or Units of Stock That Have Not Yet Vested Based on 12/31 Closing Price $42.22 ($) (Note 2)**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Yet Vested (#) (Note 3)**	**Equity Incentive Plan Awards: Market or Payout Value or Unearned Shares, Units or Other Rights That Have Not Yet Vested ($) (Note 3)**
Crane	285,000	—	39.21	04/02/22	278,970	11,778,113	623,192	26,311,166
	94,000	—	43.40	01/24/21	—	—	—	—
Cornew	70,000	—	39.81	03/12/22	77,445	3,269,728	165,362	6,981,584
Wright	—	—	—	—	12,951	546,791	27,648	1,167,299
Pacilio	—	—	—	—	56,052	2,366,515	119,684	5,053,058
Hanson	—	—	—	—	78,478	3,313,341	82,150	3,468,373
McHugh	—	—	—	—	44,905	1,895,889	94,898	4,006,594

Notes to Outstanding Equity Table

(1) Non-qualified stock options were previously granted to NEOs pursuant to the Company's long-term incentive plans. All grants are fully vested and expire on the tenth anniversary of the grant date.

(2) The amount shown includes unvested restricted stock unit awards and the performance share award earned for the performance period beginning January 1, 2018 and ending December 31, 2020, which vested on January 25, 2021. The unvested restricted stock unit awards are composed of the final third of the award made in January 2018, which vested on January 25, 2021; two-thirds of the award made in February 2019, half of which vested on January 25, 2021 and half of which will vest on the date of the Exelon Compensation Committee's first regular meeting in 2022; and the full award granted on January 27, 2020, one-third of which vested on January 25, 2021 and one-third of which will vest on the date of each of the Exelon Compensation Committee's first regular meetings in 2022 and 2023, respectively. All RSU awards accrue additional shares through automatic dividend reinvestment. For Mr. Hanson, the amount shown includes grants of 40,000 restricted stock units awarded on January 29, 2018, which vest on January 29, 2022. All shares are valued at $42.22, the closing price on December 31, 2020.

(3) The amount shown includes the target performance share awards granted on February 4, 2019 for the performance period ending December 31, 2021 and the target performance share awards granted on January 27, 2020 for the performance period ending December 31, 2022. These target awards have been increased to reflect the highest level of performance for the period, 200%. All shares are valued at $42.22, the closing price on December 31, 2020.

2020 Option Exercises and Stock Vested

	Option Awards		Stock Awards (Note 1)	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
Crane	—	—	300,152	14,188,163
Cornew	—	—	86,120	4,070,907
Wright	—	—	14,403	680,841
Pacilio	—	—	62,333	2,946,463
Hanson	—	—	42,780	2,022,215
McHugh	—	—	44,666	2,111,376

Notes to Option Exercises and Stock Vested Table

(1) Share amounts are composed of the following tranches of prior awards that vested on January 27, 2020: the performance share awards granted for the performance period of January 1, 2017 through December 31, 2019; the final third of the RSU awards granted in January 2017, the second third of the RSU awards granted in January 2018 and the first third of the RSU awards granted in January 2019. All of these awards were valued at $47.27 upon vesting.

Pension Benefits

Exelon sponsors the Exelon Corporation Retirement Program, a defined benefit pension plan that includes the Service Annuity System (SAS), a traditional pension plan covering NEOs who commenced employment prior to January 1, 2001 and the Cash Balance Pension Plan ("*CBPP*"), an account-based plan covering eligible NEOs hired between January 1, 2001, and February 1, 2018, and certain NEOs who previously elected to transfer to the CBPP from the SAS. Exelon also sponsors the Pension Plan of Constellation Energy Group, Inc. ("*CEG Pension Plan*"), which covers certain legacy Constellation Energy Group, Inc. employees. It includes a traditional pension formula for employees hired before January 1, 2000, and a pension equity formula ("*PEP*") for employees hired thereafter or who elected to participate in that formula. The Retirement Program and CEG Pension Plan are intended to be tax-qualified under Section 401(a) of the Internal Revenue Code.

Service Annuity System ("SAS")

For NEOs participating in the SAS, the annuity benefit payable at normal retirement age is equal to the sum of 1.25% of the participant's earnings as of December 25, 1994, reduced by a portion of the participant's Social Security benefit as of that date, plus 1.6% of the participant's highest average annual pay, multiplied by the participant's years of credited service (up to a maximum of 40 years). Pension-eligible compensation for the SAS's Final Average Pay Formula includes base pay and annual incentive awards. Benefits under the SAS are vested after five years of service.

The "normal retirement age" under the SAS is 65. The plan also offers an early retirement benefit prior to age 65, which is payable if a participant retires after attainment of age 50 and completion of 10 years of service. The annual pension payable under the plan is determined as of the early retirement date, reduced by 2% for each year of payment before age 60 to age 58, then 3% for each year before age 58 to age 50. In addition, under the SAS, the early retirement benefit is supplemented prior to age 65 by a temporary payment equal to 80% of the participant's estimated monthly Social Security benefit. The supplemental benefit is partially offset by a reduction in the regular annuity benefit.

Cash Balance Pension Plan ("CBPP")

For NEOs who participate in the CBPP, a notional account is established for each participant, and the account balance grows as a result of annual benefit credits and annual investment credits. NEOs who transferred from the SAS to the CBPP also have a frozen transferred SAS benefit and received a “transition” credit based on age, service and compensation at the time of transfer. When the CBPP was initially established in 2001, it provided an annual benefit credit of 5.75% of an employee’s base pay and annual incentive award for the year, and an annual investment credit based on the average of that year’s S&P 500 stock index return and the 30-year bond rate for the month of November (subject to 4% minimum). The benefit and investment credit rates have been subsequently modified periodically pursuant to U.S. Treasury Department guidance on cash balance plans. NEO participants in the CBPP currently receive an annual benefit credit ranging from 7.0% to 10.5% (depending on length of service) of base salary and annual incentive award, and an annual investment credit based on the third segment spot rate of interest on long-term investment grade corporate bonds for the month of November of the year (subject to a 4% minimum). Benefits vest after three years of service and are payable in an annuity or a lump sum at any time following termination of employment. Apart from the benefit credits and the vesting requirement, years of service are not relevant to a determination of accrued benefits under the CBPP.

In 2019, Generation and its subsidiaries also provided a one-time Transition Benefit Credit to all CBPP participants in recognition of the transition to a fully fixed income investment credit rate. The amount of the credit ranged from 0% to 30.5% of 2018 annualized base pay, based on years of service as of December 31, 2007.

Pension Plan of Constellation Energy Group, Inc. (CEG Pension Plan)

For NEOs who participate in the PEP, a lump sum benefit amount is computed based on covered earnings multiplied by a total credit percentage. Covered earnings are equal to the average of the highest three of the last five twelve-month periods’ base pay plus annual incentive awards. The total service credit percentage is equal to the sum of the credit percentages based on the following formula: 5% per year of service through age 39, 10% per year of service from age 40 to age 49, and 15% per year of service after age 49. No benefits are available under the PEP until a participant has at least three years of vesting service. Benefits payable under the PEP are paid as an annuity unless a participant elects a lump sum within 60 days after separation.

Supplemental Management Retirement Plan (“SMRP”) and
Constellation Energy Group, Inc. Benefits Restoration Plan (“CEG BRP”)

All NEOs participate in either the SMRP or the CEG BRP. The SMRP and CEG BRP provides supplemental benefits to the benefits provided under the tax-qualified Retirement Program and CEG Pension Plan, respectively, for individuals whose annual compensation exceeds the limits imposed under the Internal Revenue Code. Under the terms of the SMRP and the CEG BRP, participants are provided the amount of benefits they would have received under the SAS, CBPP or PEP but for the application of the Internal Revenue Code limits.

Up to two years of service credits may be provided under the SMRP upon a qualifying termination of employment under severance or change in control agreements or awards that are intended to make up for lost pension benefits from another employer.

The amount of the change in the pension value for each of the NEOs is the amount included in the Summary Compensation Table above. The present value of each NEO’s accumulated pension benefit is shown in the following tables. The present value for CBPP participants is the account balance.

2020 Pension Benefits

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
Crane	SAS	22.26	1,685,578	—
	SMRP[(a)]	32.26	19,344,451	—
Cornew	CBPP	26.59	962,826	—
	SMRP	26.59	2,293,831	—
Wright	PEP	17.33	506,333	—
	CEG BRP	17.33	893,213	—
Pacilio	SAS	38.53	3,179,938	—
	SMRP	38.53	11,327,758	—
Hanson	SAS	32.30	2,415,927	—
	SMRP	32.30	6,220,625	—
McHugh	CBPP	18.79	327,631	—
	SMRP	18.79	353,797	—

a) Based on discount rates prescribed by the SEC proxy disclosure guidelines, Mr. Crane's non-qualified SMRP present value is $19,344,451. Based on lump sum plan rates for immediate distributions under the non-qualified plan, the comparable lump sum amount applicable for service through December 31, 2020 is $28,495,474. Note that, in any event, payments made upon termination may be delayed by six months in accordance with U.S. Treasury Department guidance.

Deferred Compensation Programs

Exelon Corporation Deferred Compensation Plan

The Exelon Corporation Deferred Compensation Plan is a non-qualified plan that permits the NEOs to defer certain cash compensation to facilitate tax and retirement planning. The Deferred Compensation Plan also permits Generation and its subsidiaries to credit related matching contributions that would have been contributed to the Exelon Corporation Employee Savings Plan (the Exelon's tax-qualified 401(k) plan) but for the applicable limits under the Internal Revenue Code.

Exelon Corporation Employee Savings Plan

The Employee Savings Plan is intended to be tax-qualified under Sections 401(a) and 401(k) of the Internal Revenue Code. Exelon maintains the Employee Savings Plan to attract and retain qualified employees, including the NEOs, and encourage retirement savings, which under the Plan may be supplemented by Generation and its subsidiaries' matching contributions. Generation and its subsidiaries maintain the excess matching feature of the Deferred Compensation Plan to enable highly compensated employees to save for retirement to the extent they otherwise would have, were it not for the limits established by the IRS.

Once participants in the Employee Savings Plan reach their statutory contribution limit during the year, their elected payroll contributions and Generation and its subsidiaries' matching contribution will be credited to their accounts in the Deferred Compensation Plans. The investment options under the Deferred Compensation Plan consist of a basket of investment fund benchmarks substantially the same as those funds available through the Employee Savings Plan. Deferred amounts represent unfunded, unsecured obligations of Generation and its subsidiaries.

2020 Nonqualified Deferred Compensation

Name	Executive Contributions in 2020 ($) (Note 1)	Registrant Contributions in 2020 ($) (Note 2)	Aggregate Earnings in 2020 ($) (Note 3)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at 12/31/20 ($) (Note 4)
Crane	75,425	44,179	(12,854)	—	2,336,947
Cornew	19,824	24,272	(8,926)	—	726,658
Wright	—	—	—	—	—
Pacilio	65,475	28,906	141,961	—	1,391,234
Hanson	56,510	21,897	6,846	—	200,703
McHugh	35,413	17,620	(8,029)	—	72,528

Notes to Nonqualified Deferred Compensation Table

(1) The full amount shown for executive contributions is included in the base salary figures for each NEO shown above in the Summary Compensation Table.

(2) The full amount shown under registrant contributions is included in Generation and its subsidiaries' contributions to savings plans for each NEO shown above in the All Other Compensation Table.

(3) The amount shown under aggregate earnings reflects the NEOs' gain or loss based upon the individual allocation of his notional account balance into the basket of mutual fund benchmarks. These gains or losses do not represent current income to the NEO and have not been included in any of the compensation tables shown above.

(4) For all NEOs the aggregate balance shown includes those amounts, both executive contributions and registrant contributions, that have been disclosed either as base salary as described in Note 1 or as Generation and its subsidiaries' contributions under all other compensation as described in Note 2 for the current fiscal year ending December 31, 2020.

Potential Payments upon Termination or Change in Control

Each NEO is entitled to compensation in the event his or her employment terminates or upon a change in control. The Exelon Compensation Committee adopted changes to severance and change in control benefits effective in 2020, with the amount of benefits payable being contingent upon a variety of factors, including the circumstances under which employment terminates.

Severance Benefits

NEOs are entitled to certain payments and benefits in connection with a termination of employment other than for cause (which generally includes refusal to perform duties, willful or reckless acts or omissions, commission of a felony, a material violation of the Code of Business Conduct, or any breach of a restrictive covenant) or disability or resignation for good reason (which generally includes certain reductions in salary, demotions or material reductions in the NEO's position or duties) as provided for in the Senior Management Severance Plan ("*SMSP*").

The "Severance Period" is 24 months after termination of employment for all NEOs except for Mr. Wright. The Severance Period for Mr. Wright is 15 months. Benefits under the Plan include the following items.

Severance Pay	Continued payment of base salary for the applicable Severance Period
Annual Incentive	Target annual incentive awards for the applicable Severance Period and a pro-rated annual incentive award for the year in which the termination of employment occurs.
	1. <u>RSUs</u>: Unvested awards are prorated based on date of termination and vest

Equity Awards	2. LTIP (including performance shares): Prorated portion vests based on actual performance; payable at the time provided for in the award terms 3. Stock Options: Outstanding awards are exercisable to the extent the award was exercisable on the date of termination and may be exercised until the earlier of 90 days from termination date or expiration date of award.
SMRP Benefits	Benefit equal to the amount payable under the SMRP determined as if the SMSP benefit were fully vested and the severance pay constituted covered compensation for purposes of the SMSP.
Retirement Benefits	If applicable, benefits equal to the actuarial equivalent present value of any non-vested accrued benefit under Exelon's qualified defined benefit retirement plan. All current NEOs are fully vested.
Insurance, Health and Welfare Benefits	Life, disability, accident, health and other welfare benefit coverage continues during the severance pay period on the same terms and conditions applicable to active employees, followed by retiree health coverage if applicable.(1)
Financial Planning	Outplacement and financial planning services for at least 12 months.

(1) Executives are eligible for retirement benefits, including retiree health coverage, if they are at least 55 years old and have completed at least 10 years of service.

Payments under the SMSP are subject to reduction by Exelon to the extent necessary to avoid imposition of excise taxes imposed by Section 4999 of the Internal Revenue Code on excess parachute payments or under similar state or local law.

Post-Termination Arrangement for Mr. Cornew

As previously announced, Mr. Cornew's role was eliminated in connection with organizational restructurings and ongoing succession management. Mr. Cornew entered into a separation agreement providing for his receipt of standard benefits provided under the non-change in control provisions of the SMSP, subject to customary waivers, releases, non-solicitation and non-compete provisions for two years following his departure dates. Benefits include a severance benefit equal to two times the sum of his base salary and target annual incentive awards. In addition, he is eligible for a pro-rated annual incentive award for 2021 based on the achievement of business performance metrics consistent with those applied to executive peers. In accordance with the terms in effect on the date of grant for outstanding equity awards, a portion of the performance share unit awards granted to Mr. Cornew will be prorated to reflect the portion of the performance period during which he was employed and all such awards will remain outstanding and subject to their original performance-based vesting schedule. Outstanding restricted stock units will vest and any outstanding stock options will remain exercisable until their expiration date. Mr. Cornew will also be entitled to receive accrued pension benefits, health care coverage, and other SERP or deferred compensation benefits, as applicable and as described above.

Mr. Cornew also received home sale relocation benefits under which Exelon's relocation vendor purchased the Baltimore residence Mr. Cornew acquired in connection with his relocation to Baltimore to take the role of Chief Executive Officer of Constellation business unit. The value of the benefit is $216,640, based on a determination of the difference between the average of two appraisals and the price Mr. Cornew paid for the home in 2012 plus qualified capital improvements as provided for under the executive relocation program's standard terms.

Change in Control Benefits

NEOs are eligible for certain benefits upon certain involuntary terminations or a resignation for "good reason" (which generally includes certain reductions in compensation and benefits, reductions in position, duties or responsibilities, relocations or breaches by the company of the SMSP) in connection with a change in control of Exelon Corporation. Pursuant to the terms of his separation agreement, Mr. Cornew is not eligible for change in control benefits.

Under the SMSP, a "change in control" includes any of the following: (a) when any person or group acquires 20% of Exelon's then outstanding common stock or of voting securities; (b) the incumbent members of the Exelon board (or new members nominated by a majority of incumbent directors) cease to constitute at least a majority of the members of the Exelon board; (c) consummation of a reorganization, merger or consolidation, or sale or other disposition of at least 50% of Exelon's operating assets (excluding a transaction where Exelon shareholders retain at least 60% of the voting power); or (d) upon shareholder approval of a plan of complete liquidation or dissolution.

If the executive resigns for good reason or his or her employment is terminated by Exelon other than for cause or disability, during the period commencing 90 days before a change of control or during the 24-month period following a change in control, the executive is entitled to the benefits outlined below.

Severance Pay	The executive receives 2.99 times base salary (1.5 times for Mr. Wright) to be paid in substantially equal regular payroll installments.
Annual Incentive	Target annual incentive award for a period of 2.99 years (1.5 years for Mr. Wright) after termination of employment and a pro-rated annual incentive award for the year in which the termination of employment occurs.
Equity Awards	1. RSUs: Unvested awards vest 2. LTIP (including performance shares): Prorated portion vests based on actual performance; payable at the time provided for in the award terms 3. Stock Options: Outstanding awards are immediately exercisable and may be exercised until the earlier of 5 years from termination date or expiration date of award.
SMRP Benefits	Benefit equal to the amount payable under the SMRP determined as if (1) the executive had 18 additional months (2.99 years for Mr. Crane; 15 months for Mr. Wright) of age and years of service and (2) the severance pay constituted covered compensation for purposes of the SMRP.
Retirement Benefits	Benefits equal to the actuarial equivalent present value of any non-vested accrued benefit under Exelon's qualified defined benefit retirement plan. All current NEOs are fully vested.
Insurance, Health and Welfare Benefits	Life, disability, accident, health and other welfare benefit coverage continues during the severance pay period on the same terms and conditions applicable to active employees, followed by retiree health coverage if applicable.[1]
Financial Planning	Outplacement and financial planning services for at least 12 months.

Executives are eligible for retirement benefits, including retiree health coverage, if they are at least 55 years old and have completed at least 10 years of service.

2020 Estimated Value of Benefits to be Received Upon Retirement

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs, except Mr. Cornew, assuming they retired as of December 31, 2020. As of December 31, 2020, Mr. McHugh had not reached the minimum age required to be eligible for retirement benefits. These payments and benefits are in addition to the present value of the accumulated benefits from each NEO's qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in the tables within the Deferred Compensation section.

Name	Cash Payment ($) (Note 1)	Value of Unvested Equity Awards ($) (Note 2)	Total Value of All Payments and Benefits ($) (Note 3)
Crane	1,898,000	27,643,000	29,541,000
Cornew	—	—	—
Wright	309,000	—	309,000
Pacilio	1,002,000	5,459,000	6,461,000
Hanson	595,000	3,748,000	4,343,000
McHugh	—	—	—

Notes to Benefits to be Received Upon Retirement Table

(1) Under the terms of the 2020 AIP, a pro-rated actual incentive award is payable upon retirement based on the number of days worked during the year of retirement. The amount above represents the executive's 2020 annual incentive payout after Generation or its applicable subsidiary/business unit performance was determined.

(2) Includes the value of the executives' unvested performance share awards granted in 2018, 2019, and 2020 assuming target performance and the accelerated portion of the executives' RSU awards that, per applicable awards agreements, would vest upon retirement. The value of the shares is based on Exelon's closing stock price on December 31, 2020 of $42.22.

(3) Estimate of total payments and benefits based on a December 31, 2020 retirement date.

2020 Estimated Value of Benefits to be Received Upon Termination due to Death or Disability

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs, except Mr. Cornew, assuming employment is terminated due to death or disability as of December 31, 2020. These payments and benefits are in addition to the present value of the accumulated benefits from the NEOs' qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in tables within the Deferred Compensation section.

Name	Cash Payment ($) (Note 1)	Value of Unvested Equity Awards ($) (Note 2)	Total Value of All Payments and Benefits ($) (Note 3)
Crane	1,898,000	27,643,000	29,541,000
Cornew	—	—	—
Wright	309,000	1,262,000	1,571,000
Pacilio	1,002,000	5,459,000	6,461,000
Hanson	595,000	5,437,000	6,032,000
McHugh	612,000	4,321,000	4,933,000

Notes to Benefits to be Received Upon Termination due to Death or Disability Table

(1) Under the terms of the 2020 AIP, a pro-rated actual incentive award is payable upon death or disability based on the number of days worked during the year of termination. The amount above represents the executives' 2020 annual incentive payout after Generation's or its applicable subsidiary's and/or business unit's performance was determined.

(2) Includes the value of the executives' unvested performance share awards granted in 2018, 2019, and 2020 assuming target performance and the accelerated portion of the executives' RSU awards that, per

applicable awards agreements, would vest upon death or disability. The value of the shares is based on Exelon's closing stock price on December 31, 2020 of $42.22.

(3) Estimate of total payments and benefits based on a December 31, 2020 termination due to death or disability.

2020 Estimated Value of Benefits to be Received Upon Involuntary Separation Not Related to a Change in Control

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs assuming they were terminated as of December 31, 2020 under the terms of the SMSP. These payments and benefits are in addition to the present value of the accumulated benefits from the NEOs' qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in the tables within the Deferred Compensation section.

Name	Cash Payment ($) (Note 1)	Retirement Benefit Enhancement ($) (Note 2)	Value of Unvested Equity Awards ($) (Note 3)	Health and Welfare Benefit Continuation ($) (Note 4)	Perquisites And Other Benefits ($) (Note 5)	Total Value of All Payments and Benefits ($) (Note 6)
Crane	8,234,000	2,471,000	27,643,000	112,000	40,000	38,500,000
Cornew	4,769,000	362,000	7,544,000	44,000	40,000	12,759,000
Wright	1,158,000	1,009,000	1,262,000	21,000	40,000	3,490,000
Pacilio	4,232,000	1,200,000	5,459,000	46,000	40,000	10,977,000
Hanson	3,115,000	1,411,000	4,735,000	39,000	40,000	9,340,000
McHugh	2,977,000	—	4,240,000	45,000	40,000	7,302,000

Notes to Benefits to be Received Upon Involuntary Separation Not Related to a Change in Control Table

(1) Represents the estimated severance benefit equal to 2.0 times (1.25 times for Mr. Wright) the sum of (i) current base salary and (ii) the target annual incentive for the year of termination, plus a pro-rated annual incentive award for the year in which termination occurs. The amount above represents the executives' 2020 annual incentive payout after Generation or its applicable subsidiary/business unit performance was determined.

(2) Represents the estimated retirement benefit enhancement that consists of a one-time lump sum payment based on the actuarial present value of a benefit under the non-qualified pension plan assuming that the severance pay period was taken into account for purposes of vesting, and the severance pay constituted covered compensation for purposes of the non-qualified pension plan.

(3) Includes the value of the executives' unvested performance share awards granted in 2018, 2019, and 2020 assuming target performance and the accelerated portion of the executives' RSU awards that, per applicable awards agreements, would vest upon an involuntary separation not related to a change of control. The value of the shares is based on Exelon's closing stock price on December 31, 2020 of $42.22.

(4) Estimated costs of healthcare, life insurance, and long-term disability coverage which continue during the severance period.

(5) Estimated costs of outplacement and financial planning services for up to 12 months for all NEOs.

(6) Estimate of total payments and benefits based on a December 31, 2020 termination date.

2020 Estimated Value of Benefits to be Received Upon a Qualifying Termination following a Change in Control

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs, except Mr. Cornew, assuming they were terminated upon a qualifying change in control as of December 31, 2020. These payments and benefits are in addition to the present value of accumulated benefits from the NEOs' qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in tables within the Deferred Compensation section.

Name	Cash Payment ($) (Note 1)	Retirement Benefit Enhancement ($) (Note 2)	Value of Unvested Equity Awards ($) (Note 3)	Health and Welfare Benefit Continuation ($) (Note 4)	Perquisites And Other Benefits ($) (Note 5)	Total Value of All Payments and Benefits ($) (Note 6)
Crane	11,370,000	3,976,000	27,643,000	168,000	40,000	43,197,000
Cornew	—	—	—	—	—	—
Wright	1,328,000	1,082,000	1,262,000	26,000	40,000	3,738,000
Pacilio	5,831,000	1,854,000	5,459,000	68,000	40,000	13,252,000
Hanson	4,362,000	1,877,000	5,437,000	59,000	40,000	11,775,000
McHugh	4,148,000	—	4,321,000	68,000	40,000	8,577,000

Notes to Benefits to be Received Upon a Qualifying Termination following a Change in Control Table

(1) Represents the estimated cash severance benefit equal to 2.99 times (1.5 times for Mr. Wright) the sum of (i) current base salary and (ii) the annual incentive award at target, plus a pro-rated annual incentive award for the year in which termination occurs. The amount above represents the executives’ 2020 annual incentive payout after Generation or its applicable subsidiary/business unit performance was determined.

(2) Represents the estimated retirement benefit enhancement that consists of a one-time lump sum payment based on the actuarial present value of a benefit under the non-qualified pension plan assuming that the severance pay period was taken into account for purposes of vesting, and the severance pay constituted covered compensation for purposes of the non-qualified pension plan.

(3) Includes the value of the executives’ unvested performance shares, all of which will vest upon termination at the actual level earned and awarded (it is assumed the 2018, 2019, and 2020 performance shares are earned at target) and the accelerated portion of the executives’ RSUs that would vest upon a qualifying termination following a change in control. The value of the shares is based on Exelon’s closing stock price on December 31, 2020 of $42.22.

(4) Estimated costs of healthcare, life insurance and long-term disability coverage which continue during the severance period.

(5) Estimated costs of outplacement and financial planning services for up to 12 months for all NEOs.

(6) Estimate of total payments and benefits based on a December 31, 2020 termination date.

Director Compensation

The Company’s non-employee director compensation program will be subject to the review and approval of the Company’s board upon the recommendation of the Corporate Governance Committee after the distribution. The Exelon Corporate Governance Committee of the Exelon board of directors has reviewed an initial director compensation program for the Company that is designed to enable ongoing attraction and retention of highly qualified directors and to address the time, effort, expertise and accountability required of active board membership. This program is described in further detail below.

Annual Retainer

The following chart shows the initial annual retainers for non-employee directors as well as additional fees paid to the independent chair and committee chairs. Directors serving in multiple leadership roles will receive incremental compensation for each role.

Role	Cash ($)	Deferred Stock Units ($)	Total ($)
All Directors (base retainer)	125,000	155,000	280,000
Independent Board Chair			
Audit Committee Chair	25,000		

Role	Cash ($)	Deferred Stock Units ($)	Total ($)
Compensation Committee Chair	20,000		
Governance Committee Chair	20,000		
Nuclear Oversight Committee Chair	20,000[(1)]		

(1) All members of the Nuclear Oversight Committee, including the chair, receive a $20,000 retainer.

Directors do not receive additional compensation for attending regularly scheduled board or committee meetings. All board fees are paid quarterly in arrears. New directors joining the board receive a prorated fee for the quarter based on the date of their election.

Directors may elect to defer any portion of cash compensation into a non-qualified multi-fund deferred compensation plan. Under the plan, each director has an unfunded account where the dollar balance can be invested in one or more of several mutual funds. Fund balances are settled in cash and may be distributed in a lump sum or in annual installment payments upon a director reaching age 65, age 72, or upon departure from the board.

Deferred stock units earn dividend equivalents which are reinvested in the deferred stock accounts as additional stock units. The account balance of deferred stock units will be settled in shares of the Company common stock and may be distributed in a lump sum or in annual installments upon reaching age 65, age 72, or upon a director’s departure from the board.

For a description of the adjustments that are expected to be made to outstanding Exelon equity-based compensation awards, including those held by Company directors who previously served on the Exelon board of directors, in connection with the distribution, see the section titled “Security Ownership of Certain Beneficial Owners and Management.”

Director Share Ownership Requirements

Each non-employee director will be required to own shares of Company common stock (including deferred stock units). Directors must achieve the required stock ownership level within five years after joining the board.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended December 31, 2020, the Company was not an independent company and did not have a compensation committee or any other committee serving a similar function.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Existing Arrangements with Exelon

We have a number of existing arrangements whereby affiliates of Exelon and affiliates of the Company have provided various services to each other. In connection with the separation, we (including our subsidiaries) expect to enter into agreements with Exelon that have either not existed historically, or that may be on different terms than the terms of the existing arrangement or agreements.

Agreements with Exelon Related to the Separation

This section of the information statement summarizes material agreements between us and Exelon that will govern the ongoing relationships between the two companies after the separation and are intended to provide for an orderly transition to our status as an independent, publicly-traded company. Additional or modified agreements, arrangements and transactions, each of which would be negotiated at arm's length, may be entered into between us and Exelon after the separation.

Following the separation, we and Exelon will operate independently, and neither company will have any ownership interest in the other. Before the separation, we will enter into a separation agreement and several other agreements with Exelon related to the separation. These agreements will govern the relationship between us and Exelon after completion of the separation and provide for the allocation between us and Exelon of various assets, liabilities, rights and obligations. The following is a summary of the terms of the material agreements we expect to enter into with Exelon. These summaries are qualified in their entirety by reference to the full text of the applicable agreements, which are filed as exhibits to the registration statement of which this information statement forms a part.

Separation Agreement

We intend to enter into a separation agreement with Exelon prior to the distribution of shares of our common stock to Exelon shareholders. The separation agreement will provide for the allocation of assets and liabilities between us and Exelon and will establish certain rights and obligations between the parties following the distribution.

Transfer of Assets and Assumption of Liabilities. The separation agreement will identify certain transfers of assets and assumptions of liabilities that are necessary in advance of our separation from Exelon so that we and Exelon retain the assets of, and the liabilities associated with, our respective businesses. The separation agreement will also provide for the settlement or extinguishment of certain liabilities and other obligations between us and Exelon. See "Unaudited Pro Forma Condensed Consolidated Financial Statements." In particular, the separation agreement will generally provide that:

- all of the assets of the Constellation business not already owned by us and owned by Exelon prior to the distribution will be transferred to us;
- all of the assets of the businesses and operations conducted by Exelon, other than the Constellation business, not already owned by Exelon and owned by us prior to the distribution will be transferred to Exelon;
- all of the liabilities (whether accrued, contingent or otherwise) of the Constellation business that are obligations of Exelon prior to the distribution will be assumed by us;
- all of the liabilities (whether accrued, contingent or otherwise) of the business and operations conducted by Exelon, other than the Constellation business, that are our obligations prior to the distribution will be assumed by Exelon; and
- allocation of tax- and employee-related assets and liabilities will be addressed separately in a Tax Matters Agreement and Employee Matters Agreement, respectively. For more information, see the sections entitled "— Tax Matters Agreement" and "— Employee Matters Agreement" below in this information statement.

Further Assurances. To the extent that any transfers of assets or assumptions of liabilities contemplated by the separation agreement have not been consummated on or prior to the date of the distribution, the parties will agree to cooperate reasonably with each other and use commercially reasonable efforts to effect such transfers or assumptions as promptly as reasonably practicable following the date of the distribution. In addition, each of the parties will agree to cooperate reasonably with the other and use commercially reasonable efforts to take or to cause to be taken all actions, and to do, or to cause to be done, all things reasonably necessary under applicable law or contractual obligations to consummate and make effective the transactions contemplated by the separation agreement and the ancillary agreements.

Shared Contracts. We and Exelon will agree to use reasonable commercial efforts to cooperate to divide, partially assign, modify or replicate all agreements relating in a material respect to both our and Exelon's businesses such that we shall be the beneficiary of the rights and responsible for the obligations of that portion of the agreement relating to the Constellation business and Exelon shall be the beneficiary of the rights and responsible for the obligations of that portion of the agreement relating to the Exelon business.

Credit Support. We will agree to use our commercially reasonable efforts to arrange, prior to the distribution, for the replacement of all guarantees, covenants, indemnities, surety bonds, letters of credit or similar assurances of credit support currently provided by or through Exelon or any of its affiliates for the benefit of us or any of our affiliates. To the extent we are not able to replace any such credit support, we will agree, and will agree to cause any of our subsidiaries that has assumed the liability with respect to such credit support instrument, to indemnify Exelon for such liability. Exelon may request cash or a letter of credit to provide collateral support for any such Exelon-provided credit support that remains outstanding after the distribution if Generation's credit rating by one or more of S&P, Moody's or Fitch falls below investment grade.

Representations and Warranties. In general, neither we nor Exelon will make any representations or warranties regarding any assets or liabilities transferred or assumed, any consents or approvals that may be required in connection with such transfers or assumptions, the value or freedom from any lien or other security interest of any assets transferred, the absence of any defenses relating to any claim of either party or the legal sufficiency of any conveyance documents, or any other matters.

Except as expressly set forth in the separation agreement or in any ancillary agreement, all assets will be transferred on an "as is, where is" basis.

Internal Transactions. The separation agreement will provide for the internal transactions described under "The Separation — Manner of Effecting the Separation — Internal Transactions" above in this information statement. Those transactions will occur prior to the distribution.

The Distribution. The separation agreement will govern certain rights and obligations of the parties regarding the proposed distribution and certain actions that must occur prior to the proposed distribution, such as the election of officers and directors and the adoption of our amended and restated articles of incorporation and amended and restated bylaws.

Prior to the distribution, Exelon will deliver all the issued and outstanding shares of our common stock to the Distribution Agent. Following the distribution date, the Distribution Agent will electronically deliver the shares of our common stock to Exelon shareholders based on each holder of Exelon common stock receiving one share of Company common stock for every three shares of Exelon common stock held by such shareholder. The Exelon board of directors will have the sole and absolute discretion to determine (and change) the terms of, and whether to proceed with, the distribution and, to the extent it determines to so proceed, to determine the date of the distribution.

Conditions. The separation agreement will provide that the distribution is subject to the satisfaction or waiver of certain conditions. For further information regarding these conditions, see "The Separation — Conditions to the Distribution." The Exelon board of directors may, in its sole discretion, determine the distribution date and the terms of the distribution and, until the distribution has occurred, the Exelon board of directors has the right to elect not to proceed with the distribution in its sole discretion, even if all of the conditions are satisfied.

Termination. The separation agreement will provide that it may be terminated by Exelon at any time in its sole discretion prior to the distribution.

Intercompany Arrangements. The separation agreement will provide that, subject to any provisions in the separation agreement or any ancillary agreement to the contrary, prior to the distribution, most intercompany accounts will be settled in the manner agreed between us and Exelon. Further, the separation agreement will provide for the termination of various intercompany agreements, except as provided in the separation agreement or any ancillary agreement to the contrary, specified existing indemnification agreements, an agreement addressing the handling of commitments made in prior mergers, and certain agreements and arrangements in the ordinary course of business.

Release of Claims and Indemnification. We and Exelon will agree to broad mutual general releases pursuant to which we will each release the other and certain related persons specified in the separation agreement from any claims against any of them that arise out of or relate to events, circumstances or actions occurring or failing to occur or alleged to occur or to have failed to occur or any conditions existing or alleged to exist at or prior to the time of the distribution. These mutual general releases will be subject to certain exceptions set forth in the separation agreement and the ancillary agreements, including the excepted intercompany agreements described in the previous paragraph and certain employment-related matters.

The separation agreement will provide for cross-indemnities that, except as otherwise provided in the separation agreement, are principally designed to place financial responsibility for the obligations and liabilities of our business with us, and financial responsibility for the obligations and liabilities of Exelon's business with Exelon.

The amount of each party's indemnification obligations will be subject to reduction by any insurance proceeds actually received by the party being indemnified. The separation agreement will also specify procedures with respect to claims subject to indemnification and related matters. Indemnification with respect to taxes will be governed solely by the tax matters agreement.

Insurance. The separation agreement will provide for the allocation among the parties of benefits under existing insurance policies for occurrences prior to the distribution and sets forth procedures for the administration of insured claims. The separation agreement will allocate among the parties the right to proceeds and the obligation to incur deductibles under certain insurance policies.

Other Matters Governed by the Separation Agreement. Other matters governed by the separation agreement will include access to financial and other information, confidentiality and access to and provision of records.

Transition Services Agreement

We intend to enter into a transition services agreement with Exelon under which Exelon will provide us with certain services, we will provide Exelon with certain services, or both of us will mutually provide certain services, for a prescribed period of time following the distribution to help ensure an orderly transition following the distribution.

Services. The services are expected to include specified accounting, finance, information technology, human resources, employee benefits and other services that are currently provided on a centralized basis by Exelon Business Services Company. The most extensive of these services will be the provision by Exelon and its third party vendors to us of information technology systems support while we establish our own standalone systems. Other services, such as accounting, finance, human resources, security and employee benefits, are expected to provide interim support as our and Exelon's staffing is filled-out post-separation. Services are to be provided in a manner, scope, nature, timeliness and quality substantially the same as the provision of those services prior to the separation. In addition, from time to time during the term of the agreement, we and Exelon may mutually agree to expand the scope of services, to provide additional services and to cease provision of any services that are no longer required.

Payment. A recipient of any such services used will pay the provider for such services at agreed amounts as set forth in the agreement. Invoices are generally expected to be sent monthly or as prescribed in the agreement. We also expect to pay a fair market value annual administrative fee, which we expect will not exceed 5-10% on all services received. Following the term of the agreement, there will be a true-up for the total charges actually incurred under the agreement as compared to the costs for the services provided.

Administration. The agreement provides for the formation of a TSA Oversight Committee to administer requests for expanded or additional services and requests to terminate scheduled services earlier than the term assigned to that service in the agreement. The committee will be composed of representatives from Exelon and us. Each of Exelon and us will also appoint a representative to act as the primary contact with respect to the provision of services for each practice area. Such practice area leads will be responsible for all aspects of the day-to-day management of their practice area.

Third Party Providers. The provider of services will use commercially reasonable efforts to obtain any required consents, licenses or approvals of any third party providers of any products or services to be used pursuant to the agreement. The receiving party shall indemnify and hold harmless the providing party against any losses that may result from arrangements and services that are provided by a third party but for which necessary consent, license or approval was sought but not obtained. Usage by the provider of services of an additional third party provider that has not been previously identified also requires consent from the recipient of services.

Representations and Warranties. Except as noted above with respect to the manner, scope, nature, timeliness and quality of services, neither we nor Exelon will make any representations or warranties regarding the services provided by it under the agreement. Except as expressly set forth in the agreement, all services will be provided on an “as is, where is” basis.

Indemnification; Limitation on Liability. Each of Exelon and us, in our respective capacity as a service provider, has agreed to indemnify the other, in its capacity as a service recipient, for losses arising from gross negligence or willful misconduct in the performance of services or a material breach of the agreement. The agreement limits a party’s liability to the aggregate amount received by that party in respect of services provided under the agreement.

Term; Termination. The term of the agreement is expected to be two-years; provided that certain services may be longer than the term and services may be extended if approved by the TSA Oversight Committee.

Tax Matters Agreement

We intend to enter into a tax matters agreement with Exelon that will govern the respective rights, responsibilities and obligations of Exelon and us after the separation with respect to tax liabilities and benefits, tax attributes, tax returns, tax contests and other tax sharing regarding U.S. federal, state, local and foreign income taxes, other tax matters and related tax returns.

Responsibility and Indemnification for Taxes. As a subsidiary of Exelon, we have (and will continue to have following the separation) joint and several liability with Exelon to the IRS for the combined U.S. federal income taxes of the Exelon consolidated group relating to the taxable periods in which we were part of that group. However, the tax matters agreement will specify the portion of this tax liability for which we will bear responsibility, and we and Exelon will each agree to indemnify each other against any amounts for which such indemnified party is not responsible. Specifically, we will generally be liable for taxes due and payable in connection with tax returns that we are required to file. We will also generally be liable for our share of certain taxes required to be paid by Exelon with respect to taxable years or periods (or portions thereof) ending on or prior to the separation to the extent that we would have been responsible for such taxes under the existing Exelon tax sharing agreement.

The tax matters agreement will also provide special rules for allocating tax liabilities in the event that the separation or any other related transaction is not completely tax-free. Our share of such taxes will be based on the facts and circumstances giving rise to such taxes, including whether such taxes are attributable to actions undertaken by us (or with respect to our stock).

Tax Refunds and Attributes. The tax matters agreement will provide for the allocation of certain pre-closing tax attributes between us and Exelon. Tax attributes generally will be allocated in accordance with the principles set forth in the existing Exelon tax sharing agreement, unless otherwise required by law. Under the tax matters agreement, we generally will be entitled to refunds for taxes for which we are responsible under the tax matters agreement. In addition, it is expected that after the separation, Exelon will have approximately $700 million in tax credit carrryforwards that may be used to offset Exelon’s future tax liabilities. A significant portion of such carryforwards were generated by our business, and under the tax matters agreement we will be entitled to be compensated for such tax credit carryforwards that are utilized by Exelon after the separation.

Restrictive Covenants. The tax matters agreement will provide for certain covenants that may restrict our ability to pursue strategic or other transactions if such transactions could implicate the tax-free nature of the separation. These restrictive covenants could prevent us from undertaking certain transactions that otherwise could optimize or maximize the value of our business. Under the tax matters agreement, we may under certain circumstances be permitted to pursue transactions that would otherwise be restricted under the tax matters agreement by obtaining a tax opinion or private letter ruling.

Tax Return Preparation. Exelon generally will prepare tax returns for pre-distribution periods for Exelon and its affiliates, other than tax returns that we are required to file on a stand-alone basis.

Representations and Warranties. We and Exelon will make certain representations to one another in the tax matters agreement as to the tax-free status of the separation.

Cooperation and Exchange of Information. Under the tax matters agreement, we and Exelon will cooperate with one another in connection with the filing of tax returns and the conduct of tax contests. As a general matter, the party responsible under the tax matters agreement for taxes that are the subject of a tax contest will have the right to control such tax contest, except that Exelon will in all events control tax contests relating to whether the separation was undertaken on a tax-free basis. We may, under certain circumstances, be required to reimburse Exelon for third party costs and expenses incurred by Exelon in connection with tax contests relating to taxes for which we may be liable.

Indemnity Obligations and Payments. Under the tax matters agreement, we and Exelon generally will be required to indemnify one another against certain liabilities, costs, or expenses arising out of the fraudulent or negligent preparation of a tax return or claim for refund.

Scope. Although valid as between the parties, the tax matters agreement will not be binding on the IRS.

Employee Matters Agreement

We intend to enter into an employee matters agreement with Exelon that will govern the respective rights, responsibilities and obligations of Exelon and the Company after the spin-off with respect to employment matters and employee and retiree compensation and benefits. The employee matters agreement will govern the allocation of employees between Exelon and the Company, the treatment of Exelon equity-based awards in connection with the spin-off and the allocation and treatment of assets and liabilities related to incentive plans, retirement plans and employee health and welfare benefit plans in which transferred employees participated prior to the spin-off.

Treatment of Exelon Equity-Based Awards. In general, the employee matters agreement will provide for Exelon equity-based awards held by our employees (including restricted stock units (RSUs), restricted stock, deferred stock units and stock options) to be converted into Company equity-based awards of equivalent value, and awards held by continuing and former Exelon employees and nonemployee directors will be adjusted to preserve their value and will continue as Exelon awards.

With respect to performance-based equity awards, Exelon performance share awards granted in 2020 will be replaced with an RSU award subject solely to time-based vesting (with shares denoted in Company stock, for our employees), with the number of underlying shares determined based on projected performance results through the end of the performance period. Exelon performance share awards granted in 2021 will be either converted to a Company performance share award of equivalent value (for our employees) or adjusted to preserve their value (for Exelon employees). Applicable performance criteria for Company performance share awards will be determined by our Board, and performance goals for adjusted Exelon performance share awards will be equitably adjusted by the Exelon Compensation Committee.

In addition, the employee matters agreement provides that, following the spin-off, we will adopt an employee stock purchase plan that is similar to Exelon’s employee stock purchase plan.

Treatment of Employee Benefit Plans. The employee matters agreement will provide for the allocation and treatment of assets and liabilities related to the Exelon qualified and non-qualified retirement plans and employee health and welfare benefit plans in which transferred employees participated prior to the spin-off.

With respect to retirement plans, certain qualified retirement plans (i.e., 401(k) and pension plans) that are specific to our employees will be transferred in whole to the Company, including all associated assets and liabilities. In addition, Exelon retirement, pension and deferred compensation plans will transfer any assets and liabilities under those plans relating to current and former employees of our business (and certain former employees not primarily associated with either business) to new Company plans, which we will establish. Exelon will retain all deferred compensation liabilities relating to nonemployee directors who continue on the Exelon board after the spin-off, as well as those relating to any former nonemployee directors of Exelon, and we will assume all liabilities relating to nonemployee directors who continue on our board after the spin-off.

With respect to health and welfare plans, we will establish and maintain new employee health and welfare benefit plans (e.g., medical, dental, vision, life insurance, disability) in which current and former employees of our business (and certain former employees not primarily associated with either business) will participate following the spin-off (including retiree health and welfare benefit plans). The employee matters agreement further requires us to recognize the transferred participants' (i) past Exelon service for participation and vesting purposes, (ii) payments made prior to the spin-off toward deductibles, co-payments and out-of-pocket maximums, (iii) beneficiary designations and (iv) flexible spending account balances. In addition, the employee matters agreement provides that amounts allocable to the Company in Exelon "voluntary employees' beneficiary association" (VEBA) trusts will be transferred to new VEBA trusts that we will establish in connection with the spin-off.

Other Benefit and Compensation Arrangements. In addition to the matters described above, the employee matters agreement includes the following provisions relating to employee benefit and compensation arrangements:

- The Company will establish an annual bonus program for our employees for performance periods ending after the spin-off;
- The Company will adopt severance plans and policies for our employees that are substantially similar to the Exelon severance plans and policies under which they were covered prior to the spin-off;
- The Company will assume liability for our employees' vacation, holiday, sick leave and personal days off, including vacation days accrued prior to the spin-off; and
- The Company will cooperate with Exelon following the spin-off on matters relating to the employee matters agreement, including by sharing employee data and personnel records.

Other Agreements. Except as required by a collective bargaining agreement or by law, each of Exelon and the Company have agreed to provide employee benefits through the remainder of 2022 that are substantially comparable to those provided as of the date of the spin-off. Following the spin-off each of Exelon and the Company will honor the collective bargaining agreements covering their respective employees. Each of Exelon and the Company have agreed that they will not hire or solicit the employees of the other company during the 12-month period following the spin-off.

Issuance and Grant of Company Common Stock to Certain Related Persons

With respect to any long-term incentive equity awards, it is expected that our compensation committee will develop programs reflecting appropriate measures, goals, targets and business objectives based on the Company's competitive marketplace. The amount and timing of any equity-based compensation to be paid to certain related persons at or following the distribution will be determined by our compensation committee and will generally be granted pursuant to a new equity incentive plan to be adopted by the Company in connection with becoming an independent, publicly-traded company.

Policies and Procedures Regarding Related Party Transactions

In connection with the separation, we expect that our board will adopt a written policy and procedures with respect to related person transactions, which will include specific provisions for the approval of related person transactions. Pursuant to this policy, related person transactions would include a transaction, arrangement or relationship or series of similar transactions, arrangements or relationships, in which we and certain enumerated related persons participate, the amount involved exceeds $120,000 and the related person has a direct or indirect material interest. We expect our nominating and governance committee will review: (i) potential conflict of interest situations on an ongoing basis, (ii) any future proposed transaction, or series of transactions, with related persons, and (iii) either approve or disapprove each reviewed transaction or series of related transactions with related persons.

In the event that a related person transaction is identified, such transaction will be reviewed and approved or ratified by our nominating and governance committee. If it is impracticable for our nominating and governance committee to review such transaction, pursuant to the policy, the transaction will be reviewed by the chair of our nominating and governance committee, whereupon the chair will report to the nominating and governance committee the approval or disapproval of such transaction.

In reviewing and approving related person transactions, pursuant to the policy, the nominating and governance committee, or its chair, shall consider all information believed to be relevant and important to a review of the transaction and shall approve only those related person transactions that are determined to be in, or not inconsistent with, our best interests and that of our shareholders, taking into account all available relevant facts and circumstances available . Pursuant to the policy, these facts and circumstances will typically include, but not be limited to, the benefits of the transaction to us; the impact on a director’s independence in the event the related person is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer; the availability of other sources for comparable products or services; the terms of the transaction; and the terms of comparable transactions that would be available to unrelated third parties or to employees generally. Pursuant to the policy, we expect that no member of the nominating and governance committee shall participate in any review, consideration or approval of any related person transaction with respect to which the member or any of his or her immediate family members is the related person.

DESCRIPTION OF CERTAIN INDEBTEDNESS

Revolving Credit Facility

Concurrently with the distribution, we expect that Generation will enter into a new credit agreement with JPMorgan Chase Bank, N.A., as administrative agent, and various financial institutions providing for a $3.5 billion revolving credit facility and maturing on the fifth anniversary of the distribution date. The credit agreement is expected to be unsecured and to allow borrowings on a revolving credit basis and the issuance of letters of credit. The credit agreement will replace Generation's existing credit agreement dated as of March 23, 2011, as amended, with JPMorgan Chase Bank, N.A., as administrative agent, and various financial institutions. A copy of the form of the expected credit agreement is filed as an exhibit to the registration statement of which this information statement is a part.

Borrowings under the credit agreement are expected to bear interest, at Generation's option, at a rate equal to a margin over either:

- the highest of a prime rate, an overnight bank funding rate plus 0.5% per annum, or the reserve-adjusted term secured overnight financing rate (SOFR) for a one-month interest period plus 1%. The rate so determined cannot be less than 1.00% per annum. Interest based on this rate is payable quarterly.
- a rate for a designated interest period based on the adjusted term SOFR rate for that interest period. Interest based on this rate is payable on the last day of the selected interest period, unless that interest period exceeds three months, in which case it is also payable upon each three-month period of the selected interest period.

The margin will be determined based upon ratings applicable to Generation's senior unsecured, non-credit enhanced debt obligations.

The credit agreement is expected to contain customary representations and warranties, covenants and events of default. The agreement is expected to require Generation to comply with a consolidated leverage ratio not to exceed 3.50 to 1.00, calculated on the basis of the trailing four fiscal quarters. The consolidated leverage ratio will be defined as consolidated indebtedness, divided by consolidated earnings before interest, taxes, amortization, depreciation and amortization. Consolidated indebtedness excludes nonrecourse indebtedness as defined in the credit agreement. In addition, the credit agreement is expected to contain negative covenants limiting the ability of the Generation and its subsidiaries to:

- create or incur liens
- make fundamental changes, including mergers, liquidation, dissolution, and sales of all or substantially all of the assets
- make changes in its line of business,
- permit any of its subsidiaries (other than excluded subsidiaries as defined in the credit agreement) to, directly or indirectly, enter into, incur or permit to exist any agreement or other arrangement that prohibits, restricts or imposes any condition upon the ability of any subsidiary to pay dividends or other distributions to Generation,

subject to certain exceptions and limitations, including carve-outs and baskets, that are expected to be set forth in the credit agreement. The credit agreement also is expected to contain certain customary events of default, including defaults triggered by a change of control and defaults on other debt.

Generation is also party to several bilateral credit agreements that support the issuance of letters of credit. The agreements are unsecured, have terms generally reflective of Generation's revolving credit agreement and include committed and uncommitted facilities. See Note 17 — Debt and Credit Agreements of Notes to Audited Consolidated Financial Statements and Note 13 — Debt and Credit Agreements of Notes to Interim Consolidated Financial Statements included in this information statement for a description of these agreements that existed at December 31, 2020.

Generation Senior Unsecured Notes

As of December 31, 2020, Generation had approximately $4.2 billion aggregate principal amount of senior notes outstanding. The notes are unsecured and are not guaranteed by any subsidiaries of Generation. The notes range in maturity from 2022 to 2042, and bear interest ranging from 3.25% to 7.60%. The indenture governing the notes requires Generation to maintain its limited liability company existence and contains restrictions on its ability to merge, consolidate or sell all or substantially all of its assets. The indenture does not limit the ability of Generation to incur additional indebtedness, including the issuance of additional notes.

Accounts Receivable Facility

On April 8, 2020, NewEnergy Receivables LLC ("*NER*"), a bankruptcy remote, special purpose entity, which is wholly-owned by us, entered into a revolving accounts receivable financing facility with a number of financial institutions and a commercial paper conduit ("*Purchasers*") to sell certain customer accounts receivable. The facility was renewed on March 29, 2021. In the renewal, the facility's term was extended through March 29, 2024, unless further renewed by the mutual consent of the parties, and the maximum funding limit was increased to $900 million. Under the facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in Generation's consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the Deferred Purchase Price, which is reflected in Other current assets on Generation's Consolidated Balance Sheets.

Nonrecourse Debt

We have issued nonrecourse debt financing, in which approximately $2.2 billion of generating assets have been pledged as collateral at December 31, 2020. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against us in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, 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 17 — Debt and Credit Agreements of Notes to Audited Consolidated Financial Statements in this information statement for more information regarding these nonrecourse debt financings.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

As of the date of this information statement, all of the outstanding shares of our common stock are beneficially owned by Exelon. After the separation, Exelon will not own any shares of our common stock. The percentage values are based on shares of our common stock outstanding as of November 30, 2021.

The following tables provide information with respect to the anticipated beneficial ownership of our common stock by:

- each of our shareholders who we believe (based on the assumptions described below) will beneficially own more than 5% of our outstanding common stock;
- each of our directors and nominees;
- each of the individuals we expect to be our named executive officers; and
- all of our directors and executive officers following the separation as a group.

To the extent our directors and executive officers own Exelon common stock at the record date of the distribution, they will participate in the distribution on the same terms as other holders of Exelon common stock.

Except as otherwise noted in the footnotes below, each person or entity identified in the tables below has sole voting and investment power with respect to the securities owned by such person or entity. Beneficial ownership is determined in accordance with the rules of the SEC. Unless otherwise indicated, the address of each director and executive officer is c/o the Company, 1310 Point Street, Baltimore, Maryland, 21231.

Immediately following the separation, we estimate that approximately 326.5 million shares of our common stock will be issued and outstanding, based on the number of shares of Exelon common stock expected to be outstanding as of the record date and based on each holder of Exelon common stock receiving one share of Company common stock for three shares of Exelon common stock. The actual number of shares of our common stock outstanding following the separation will be determined on January 20, 2022, the record date.

Name and address of beneficial owner	Shares beneficially owned	Percentage of class
The Vanguard Group(1)	27,797,113	8.56%
100 Vanguard Blvd., Malvern, PA 19355		
BlackRock, Inc.(2)	25,720,619	7.9%
55 East 52nd Street, New York, NY 10055		
Wellington Management Group LLP(3)	25,119,882	7.74%
Wellington Group Holdings LLP		
Wellington Investment Advisors Holdings LLP		
c/o Wellington Management Company LLP		
280 Congress Street, Boston, MA 02210		
State Street Corporation(4)	19,961,166	6.15%
State Street Financial Center		
One Lincoln Street, Boston, MA 02111		

(1) Based upon shares of Exelon common stock reported by The Vanguard Group in its Schedule 13G/A filed February 10, 2021, and applying the distribution ratio of one share of Company common stock for each three shares of Exelon common stock.

(2) Based upon shares of Exelon common stock reported by BlackRock, Inc. in its Schedule 13G/A filed January 29, 2021, and applying the distribution ratio of one share of Company common stock for each three shares of Exelon common stock.

(3) Based upon shares of Exelon common stock reported by Wellington Management Group LLP, Wellington Group Holdings LLP, Wellington Investment Advisors Holdings LLP, and Wellington Management Company LLP in its Schedule 13G/A filed February 3, 2021, and applying the distribution ratio of one share of Company common stock for each three shares of Exelon common stock.

(4) Based upon shares of Exelon common stock reported by State Street Corporation in its Schedule 13G filed February 16, 2021, and applying the distribution ratio of one share of Company common stock for each three shares of Exelon common stock.

Directors and Named Executive Officers	Beneficial Ownership of Common Stock (Note 1)
Laurie Brlas	3,350
Yves de Balmann	27,592
Robert Lawless	41,578
John Richardson	2,306
Joseph Dominguez	25,997
Daniel Eggers	11,229
Directors & Executive Officers as a group (11 people) (Note 2)	215,819

(1) Total share interest of Directors and executive officers, both individually and as a group, represents less than 1% of the outstanding shares of Exelon common stock.

(2) Total includes shares held by all individuals currently expected to serve as Directors, NEOs and executive officers of the Company following the distribution.

DESCRIPTION OF CAPITAL STOCK

Our articles of incorporation and bylaws will be amended and restated prior to the consummation of the separation. Except as specifically stated otherwise, the following is a summary of the material terms of our capital stock that will be contained in our amended and restated articles of incorporation (the "Articles") and our amended and restated bylaws (our "bylaws" and, together with the Articles, the "Charter Documents") as will be in effect upon completion of the separation. The summary is qualified in its entirety by reference to these documents, which you must read (along with the applicable provisions of Pennsylvania law) for complete information on our capital stock as of the time of the separation. The Charter Documents, each in a form expected to be in effect at the time of the separation, are included as exhibits to the registration statement on Form 10, of which this information statement forms a part. See "Where You Can Find More Information."

Under "Description of Capital Stock," "we," "us" and "our" refer to the Company and not to any of its subsidiaries.

Authorized Capital Stock

Our authorized capital stock currently consists of 1,000 shares of common stock, without par value. Prior to the distribution date, our board of directors and Exelon, as our sole shareholder, will approve and adopt the Articles. Under the Articles, our authorized capital stock will consist of 1,000,000,000 shares of our common stock, without par value, and 100,000,000 shares of our preferred stock, without par value.

Common Stock

We estimate that 326.5 million shares of our common stock will be issued and outstanding immediately after the separation, based on the number of shares of Exelon common stock that we expect will be outstanding as of the record date. The actual number of shares of our common stock outstanding following the separation will be determined on January 20, 2022, the record date.

Dividends. Holders of our common stock are entitled to receive ratably those dividends, if any, as may be declared from time to time by our board of directors, in its discretion, out of funds legally available therefor, subject to any preferential dividend rights of any outstanding preferred stock.

Voting Rights. Except as otherwise provided in the PBCL and subject to the rights of holders of any series of our preferred stock, the holders of our common stock have the exclusive voting power, and each holder of our common stock is entitled to one vote for every share of our common stock held by such holder. Except as otherwise provided in the PBCL or the Charter Documents, whenever any corporate action is to be taken by vote of the shareholders of the Company, it shall be authorized by the affirmative vote of a majority of the votes cast by all shareholders entitled to vote thereon at a duly organized meeting of shareholders. The shareholders of the Company may act only at a duly organized meeting.

Liquidation Rights. In the event of a liquidation, dissolution or winding up of the Company, the holders of our common stock are entitled to share ratably in all assets and funds available for distribution after the payment of all of the Company's liabilities and subject to the liquidation preferences of any outstanding preferred stock.

Other Rights and Preferences. Our common stock does not carry preemptive rights, is not redeemable, does not have any conversion rights, is not subject to further calls and is not subject to any sinking fund provisions. The rights and preferences of holders of our common stock are subject to the rights of any series of preferred stock that we may issue.

Preferred Stock

No shares of our preferred stock will be issued and outstanding immediately after the separation. Under the terms of the Articles, our board of directors has the full authority permitted by law to determine the voting rights, if any, and designations, preferences, limitations and special rights of any class or any series of any class of our preferred stock that may be desired to the extent not determined by the Articles.

Certain Anti-Takeover Provisions

Provisions of the PBCL and the Charter Documents could make it more difficult to acquire control of the Company by means of a tender offer, a proxy contest or otherwise, or to remove incumbent officers and directors. These provisions, summarized below, are expected to discourage certain types of coercive takeover practices and takeover bids that our board of directors may consider inadequate and to encourage persons seeking to acquire control of the Company to first negotiate with our board of directors. We believe that the benefits of increased protection of our ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure the Company outweigh the disadvantages of discouraging takeover or acquisition proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Potential Issuances of the Company's Preferred Stock.

Although we do not currently have any shares of our preferred stock outstanding, our board of directors is authorized under the Articles to establish, from our authorized but unissued shares of preferred stock, one or more series of shares of preferred stock and to determine, with respect to any such series of preferred stock, the terms and rights of such series, including, for example, the designation, the preferences, limitations and special rights. Thus, the rights, preferences and privileges of holders of our common stock are subject to, and may be adversely affected by, the rights of the holders of any series of our preferred stock that our board of directors may designate and we may issue in the future.

The authorized shares of the Company, including shares of preferred stock and common stock, will be available for issuance without further action by the Company's shareholders, unless such action is required by applicable law or the rules of any stock exchange or automated quotation system on which the Company's securities may be listed or traded.

Provisions for Shareholder Nominations and Shareholder Proposals at Annual Meetings.

Our bylaws require shareholders seeking to nominate persons for election as directors at an annual meeting of shareholders, or to bring other business before an annual meeting (other than a proposal submitted under Rule 14a-8 under the Exchange Act), to provide timely notice in writing. A shareholder's notice must be in proper written form and must set forth the information required under our bylaws, including information related to the shareholder giving the notice, the beneficial owner (if any) on whose behalf the nomination or proposal is made and their control persons and information about the proposal or nominee for election to our board of directors.

Provisions Relating to the Election of the Company's Board of Directors.

Under the Charter Documents, shareholders are entitled to only one vote for each share held in all elections for directors, and shareholders do not have the right to cumulate their votes for the election of directors. As required by the PBCL, directors shall be elected by a plurality of votes cast. However, in an election of directors that is not a contested election (as defined in our bylaws), if any nominee who is not an incumbent director receives a plurality of the votes cast but does not receive a majority of the votes cast, the resignation of such nominee previously tendered pursuant to our bylaws will be automatically accepted and if any nominee who is an incumbent director receives a plurality of the votes cast but does not receive a majority of the votes cast, the committee of the board authorized to nominate candidates for election to the board will make a recommendation to the board on whether to accept the director's resignation previously tendered pursuant to our bylaws or whether other action should be taken.

Classified Board. Upon completion of the separation, we expect that our board of directors will initially be divided into three classes, with Class I comprised of three directors, Class II comprised of three directors and Class III comprised of three directors. The directors designated as Class I directors will have terms expiring at the first annual meeting of shareholders following the separation, which the Company expects to hold in 2023, and each director nominee elected to succeed any such Class I director as a Class I director will hold office for a three-year term and until his or her successor is duly elected and qualified or until his or her earlier death, resignation or removal. The directors designated as Class II directors will have terms expiring at the following year's annual meeting of shareholders, which the Company expects to hold in 2024, and each director nominee elected to succeed any such Class II director as a Class II director will hold office for a two-year term and until his or her successor is duly elected and qualified or until his or her earlier death, resignation or removal. The directors designated as Class III directors will have terms expiring at the following year's annual meeting of shareholders, which the Company expects to hold in 2025, and each director nominee elected to succeed any such Class III director as a Class III director will hold office for a one-year term and until his or her successor is duly elected and qualified or until his or her earlier death, resignation or removal.

Commencing with the fourth annual meeting of shareholders following the separation, expected to be held in 2026, all of our directors will stand for election each year for annual terms, and our board will therefore no longer be divided into three classes.

Before our board of directors is declassified, it would take at least two elections of directors for any individual or group to gain control of our board of directors. Accordingly, while the classified board of directors is in effect, these provisions could discourage a third party from initiating a proxy contest, making a tender offer or otherwise attempting to gain control of the Company.

Removal of Directors. Under the Articles, except as may be otherwise provided with respect to directors elected by the holders of any series of our preferred stock, the entire board of directors or any individual director may be removed from office only with cause by vote of at least a majority of the voting power of all shares entitled to vote generally in the election of directors, voting together as a single class. Under the Articles, cause for removal will exist only if the director whose removal is proposed has been either declared of unsound mind by an order of a court of competent jurisdiction, convicted of a felony or of an offense punishable by imprisonment for a term of more than one year by a court of competent jurisdiction or deemed liable by a court of competent jurisdiction for gross negligence or willful misconduct in the performance of such director's duties to the Company.

Size of Board. Under the Articles, subject to any rights of holders of our preferred stock with respect to the election of directors upon the occurrence of a default in the payment of dividends or in the performance of another express requirement of the terms of such preferred stock, the number of directors on our board of directors may not be less than five nor more than 15. Within such limit, the number of directors constituting the whole board will be fixed solely by resolution adopted by a majority of our entire board of directors (assuming no vacancies).

Director Vacancies. Under the Articles, except as may be otherwise provided with respect to directors elected by the holders of any series of our preferred stock, vacancies in our board of directors, including vacancies resulting from an increase in the number of directors or from the failure by shareholders to elect the full authorized number of directors, may only be filled by a majority vote of the remaining members of our board, or by a sole remaining director, and each person so selected shall be a director to serve for the remainder of the full term of the directorship in which the vacancy occurred and until a successor has been elected and qualified or until his or her earlier death, resignation or removal.

Amendment to Articles.

Under the PBCL, only our board of directors, or shareholders who are entitled to cast at least 10% of the votes that all shareholders are entitled to cast on an amendment to the Articles and who comply with statutory procedures, may propose any amendment to the Articles. In addition to any other vote that may be required by law, applicable stock exchange rule or the terms of any series of our preferred stock, any amendment to the Articles will require the affirmative vote of the holders of at least a majority of the voting power of all shares of the Company entitled to vote generally in the election of directors, voting together as a single class, except for amendments on matters specified in the PBCL that do not require shareholder approval.

Amendment to Bylaws.

Except as otherwise provided in the express terms of any series of the shares of the Company, any one or more provisions of our bylaws may be altered or repealed by our board of directors except that our board of directors may not adopt, alter or repeal bylaws that the PBCL specifies may be adopted only by shareholders and our board of directors may not amend or repeal any bylaw adopted by the shareholders that provides that it shall not be amended or repealed by our board of directors. Except as otherwise provided in the express terms of any series of the shares of the Company, the shareholders may adopt new bylaws, or amend or repeal bylaws, with the affirmative vote of at least a majority of the voting power of all shares of the Company entitled to vote generally in the election of directors, voting together as a single class.

Special Meetings of Company Shareholders.

The Charter Documents do not contain a provision permitting shareholders to call a special meeting.

Shareholder Action by Written Consent.

The Charter Documents do not contain a provision permitting action by written consent of the shareholders.

Pennsylvania Anti-Takeover Statutes.

Under Section 1715 of the PBCL, directors stand in a fiduciary relation to their corporation and, as such, are required to perform their duties in good faith, in a manner they reasonably believe to be in the best interests of the corporation and with such care, including reasonable inquiry, skill and diligence, as a person of ordinary prudence would use under similar circumstances. In discharging their duties, directors may, in considering the best interests of their corporation, consider various constituencies, including, shareholders, employees, suppliers, customers and creditors of the corporation, and upon communities in which offices or other establishments of the corporation are located. Absent a breach of fiduciary duty, a lack of good faith or self-dealing, any act of the board of directors, a committee thereof or an individual director is presumed to be in the best interests of the corporation. The PBCL expressly provides that the fiduciary duty of directors does not require them to (i) redeem or otherwise render inapplicable outstanding rights issued under any shareholder rights plan; (ii) render inapplicable the anti-takeover statutes set forth in Chapter 25 of the PBCL (described below); or (iii) take any action solely because of the effect it may have on a proposed acquisition or the consideration to be received by shareholders in such a transaction.

Chapter 25 of the PBCL contains several anti-takeover statutes applicable to publicly-traded corporations. Corporations may opt out of such anti-takeover statutes under certain circumstances. We have not opted out of any of such statutes.

Section 2538 of Subchapter 25D of the PBCL requires certain transactions with an “interested shareholder” to be approved by a majority of disinterested shareholders. “Interested shareholder” is defined broadly to include any shareholder who is a party to the transaction or who is treated differently than other shareholders and affiliates of the corporation.

Subchapter 25E of the PBCL requires a person or group of persons acting in concert that acquires 20% or more of the voting shares of the corporation to offer to purchase the shares of any other shareholder at “fair value.” “Fair value” means the value not less than the highest price paid by the controlling person or group during the 90-day period prior to the control transaction, plus a control premium. Among other exceptions, Subchapter 25E does not apply to shares acquired directly from the corporation in a transaction exempt from the registration requirements of the Securities Act or to a one-step merger.

Subchapter 25F of the PBCL generally establishes a five-year moratorium on a “business combination” with an “interested shareholder.” “Interested shareholder” is defined generally to be any beneficial owner of 20% or more of the corporation’s voting stock. “Business combination” is defined broadly to include mergers, consolidations, asset sales and certain self-dealing transactions. Certain restrictions apply to business combination following the five-year period. Among other exceptions, Subchapter 25F will be rendered inapplicable if the board of directors approves the proposed business combination or approves the interested shareholder’s acquisition of 20% of the voting shares, in either case prior to the date on which the shareholder first becomes an interested shareholder.

Subchapter 25G of the PBCL provides that “control shares” lose voting rights unless such rights are restored by the affirmative vote of a majority of (i) the disinterested shares (generally, shares held by persons other than the acquirer, executive officers of the corporation and certain employee stock plans) and (ii) the outstanding voting shares of the corporation. “Control shares” are defined as shares which, upon acquisition, will result in a person or group acquiring for the first time voting control over (a) 20%, (b) 33 1/3% or (c) 50% or more of the outstanding shares, together with shares acquired within 180 days of attaining the applicable threshold and shares purchased with the intention of attaining such threshold. A corporation may redeem control shares if the acquiring person does not request restoration of voting rights as permitted by Subchapter 25G. Among other exceptions, Subchapter 25G does not apply to a merger, consolidation or a share exchange if the corporation is a party to the transaction agreement.

Subchapter 25H of the PBCL provides in certain circumstances for the recovery by the corporation of profits realized from the sale of its stock by a controlling person or group if the sale occurs within 18 months after the controlling person or group became a controlling person or group, and the stock was acquired during such 18-month period or within 24 months before such period. A controlling person or group is a person or group that has acquired, offered to acquire or publicly disclosed an intention to acquire 20% or more of the voting shares of the corporation. Among other exceptions, Subchapter 25H does not apply to transactions approved by both the board of directors and the shareholders prior to the acquisition or distribution, as appropriate.

Subchapter 25I of the PBCL mandates severance compensation for eligible employees who are terminated within 24 months after the approval of a control share acquisition. Eligible employees generally are all employees employed in Pennsylvania for at least two years prior to the control share approval. Severance equals the weekly compensation of the employee multiplied by the employee’s years of service (up to 26 years), less payments made due to the termination.

Subchapter 25J of the PBCL requires the continuation of certain labor contracts relating to business operations owned at the time of a control share approval.

Limitations on Liability of Directors and Indemnification of Directors and Officers

The PBCL authorizes corporations to limit or eliminate the personal liability of directors to corporations and their shareholders for monetary damages for any action taken as directors, unless the director has breached or failed to perform the duties of his or her office under Subchapter B of Chapter 17 of the PBCL and the breach or failure to perform constitutes self-dealing, willful misconduct or recklessness. However, this does not apply to the responsibility or liability of a director pursuant to any criminal statute or the liability of a director for the payment of taxes pursuant to federal, state or local law. The Articles include such an exculpation provision.

Our bylaws generally provide indemnification and advancement of expenses for our directors and officers to the fullest extent permitted by the PBCL. The PBCL provides that indemnification shall not be made in respect in any case where the act or failure to act giving rise to the claim for indemnification is determined by a court to have constituted willful misconduct or recklessness.

We are in the process of drafting policies meant to insure our directors and officers and those of our subsidiaries against certain liabilities they may incur in their capacities as directors and officers. Under these policies, the insurer, on our behalf, may also pay amounts for which we have granted indemnification to the directors or officers.

The limitation of liability and indemnification provisions in our bylaws may discourage shareholders from bringing a lawsuit against directors for breach of their fiduciary duties. These provisions may also have the effect of reducing the likelihood of derivative litigation against our directors and officers, even though such an action, if successful, might otherwise benefit the Company and our shareholders. However, these provisions will not limit or eliminate the Company’s rights, or those of any shareholder, to seek non-monetary relief such as an injunction or rescission in the event of a breach of a director’s fiduciary duties. The provisions will not alter the liability of directors under the federal securities laws. In addition, your investment may be adversely affected to the extent that, in a class action or direct suit, the Company pays the costs of settlement and damage awards against directors and officers pursuant to these indemnification provisions.

Exclusive Forum

The Articles provide that unless our board of directors consents in writing to an alternative forum, a state court within the Commonwealth of Pennsylvania (or if no such state court has jurisdiction, a federal district court within the Commonwealth of Pennsylvania) will be the sole and exclusive forum for

- any derivative action or proceeding brought on behalf of the Company (including any derivative suit brought to enforce any liability or duty created by the Exchange Act),
- any action asserting a claim of breach of a fiduciary duty owed by any current or former director, officer or employee of the Company to the Company or its shareholders,
- any action asserting a claim against the Company or any of its directors, officers or employees arising pursuant to any provision of the PBCL or as to which the PBCL confers jurisdiction on the Pennsylvania Courts of Common Pleas or the Charter Documents or
- any action asserting a claim against the Company or any of its directors, officers or employees governed by the internal affairs doctrine.

The Articles also provide that unless our board of directors consents in writing to an alternative forum, the federal district courts of the United States of America will be the sole and exclusive forum for the resolution of any action asserting a cause of action arising under the Securities Act. Insofar as a derivative action or proceeding seeks to enforce a liability or duty under the Exchange Act, our exclusive forum provision may be ineffective as the Exchange Act creates exclusive federal jurisdiction over suits brought to enforce any duty or liability created by the Exchange Act. Thus, although the Articles include these exclusive forum provisions, it is possible that a court could rule that these provisions are inapplicable or unenforceable. Investors cannot waive compliance with the federal securities laws and the rules and regulations thereunder.

Listing and Trading

We intend to have our shares of common stock listed on NASDAQ. We expect our shares to trade under the ticker symbol “CEG.”

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is EQ Shareowner Services.

WHERE YOU CAN FIND MORE INFORMATION

We have filed a Registration Statement on Form 10 with the SEC with respect to the shares of common stock that Exelon shareholders will receive in the distribution. This information statement does not contain all of the information contained in the Registration Statement on Form 10 and the exhibits and schedules to the Registration Statement on Form 10. Some items are omitted in accordance with the rules and regulations of the SEC. For additional information relating to us and the separation, reference is made to the Registration Statement on Form 10 and the exhibits to the Registration Statement on Form 10, which are on file at the offices of the SEC. Statements contained in this information statement as to the contents of any contract or other document referred to are not necessarily complete and in each instance, if the contract or document is filed as an exhibit, reference is made to the copy of the contract or other documents filed as an exhibit to the Registration Statement on Form 10. Each statement is qualified in all respects by the relevant reference.

The SEC maintains an Internet site at *www.sec.gov*, from which you can electronically access the Registration Statement on Form 10, including the exhibits and schedules to the Registration Statement on Form 10.

We maintain an Internet site at constellationenergy.com. Our Internet site and the information contained on that site, or connected to that site, are not incorporated into the information statement or the Registration Statement on Form 10.

As a result of the distribution, we will be required to comply with the full informational requirements of the Exchange Act. We will fulfill our obligations with respect to these requirements by filing periodic reports and other information with the SEC. We plan to make available, free of charge, on our Internet site our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, reports filed pursuant to Section 16 of the Exchange Act and amendments to those reports as soon as reasonably practicable after we electronically file or furnish such materials to the SEC.

You should rely only on the information contained in this information statement or to which we have referred you. We have not authorized any person to provide you with different information or to make any representation not contained in this information statement.

CERTAIN DEFINED TERMS

Except where the context suggests otherwise, we define certain terms in this information statement as follows:

ACE	Atlantic City Electric Company
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AESO	Alberta Electric Systems Operator
AIP	Annual Incentive Plan
Antelope Valley	Antelope Valley Solar Ranch One
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ASA	Asset Sale Agreement
Bcf	Billion cubic feet
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
CAISO	California ISO
CBPP	Cash Balance Pension Plan
CENG	Constellation Energy Nuclear Group, LLC
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
C&I	Commercial and Industrial
Clean Air Act	Clean Air Act of 1963, as amended
Clean Energy Law	Illinois Public Act 102-0662 signed into law on September 15, 2021
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CMC	Carbon Mitigation Credit
CODM	Chief Operating Decision Maker
ComEd	Commonwealth Edison Company
Company	Constellation Energy Corporation
Constellation	Constellation NewEnergy, Inc.
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DOEE	Washington, DC Department of Energy & Environment
DOJ	United States Department of Justice
DPL	Delmarva Power & Light Company
EDF	Electricite de France SA and its subsidiaries
EFEC	Emissions-Free Energy Certificate
EGR IV	ExGen Renewables IV, LLC
EGRP	ExGen Renewables Partners, LLC
EPA	United States Environmental Protection Agency
EPS	Earnings per share

ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
Exelon	Exelon Corporation
FASB	Financial Accounting Standards Board
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	United States Federal Energy Regulatory Commission
FFO	Funds from operations
FitzPatrick	James A. FitzPatrick nuclear generating station
FRCC	Florida Reliability Coordinating Council
FRR	Fixed Resource Requirement
GAAP	Generally Accepted Accounting Principles in the United States
Generation	Exelon Generation Company, LLC
GHG	Greenhouse Gas
Ginna	R. E. Ginna nuclear generating station
GWh	Gigawatt hour
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IPA	Illinois Power Agency
IRC	Internal Revenue Code of 1986, as amended
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LLRW	Low-Level Radioactive Waste
LNG	Liquefied Natural Gas
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MDE	Maryland Department of the Environment
MISO	Midcontinent Independent System Operator, Inc.
MOPR	Minimum Offer Price Rule
MW	Megawatt
MWh	Megawatt hour
NAV	Net Asset Value
NASDAQ	Nasdaq Stock Market, Inc.
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NEO	Named Executive Officer
NERC	North American Electric Reliability Corporation
NGX	Natural Gas Exchange, Inc.
NJDEP	New Jersey Department of Environmental Protection

Non-Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOSA	Nuclear Operating Services Agreement
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchase Normal Sale scope exception
NRC	United States Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PCAOB	Public Company Accounting Oversight Board
PECO	PECO Energy Company
Pepco	Potomac Electric Power Company
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PUCT	Public Utility Commission of Texas
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RIN	Renewable Identification Number
RMC	Risk Management Committee
ROE	Return on equity
ROU	Right-of-use
RPG	Renewable Power Generation
RPM	PJM Reliability Pricing Model

RPS	Renewable Energy Portfolio Standards
RSA	Restricted Stock Award
RSU	Restricted Stock Unit
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SAIFI	System Average Interruption Frequency Index
SAS	Service Annuity System
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SMRP	Supplemental Management Retirement Plan
SNF	Spent Nuclear Fuel
SolGen	SolGen, LLC
SPP	Southwest Power Pool
STEM	Science, Technology, Engineering, and Mathematics
TDC	Total Direct Compensation
TMI	Three Mile Island nuclear facility
TSR	Total Shareholder Return
TWh	Terawatt-hour
Upstream	Natural gas and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidated financial statements of Exelon Generation Company, LLC for the nine months ended September 30, 2021 and 2020

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Nine Months Ended September 30,	
(In millions)	**2021**	**2020**
Operating revenues		
Operating revenues	$13,245	$12,340
Operating revenues from affiliates	872	932
Total operating revenues	14,117	13,272
Operating expenses		
Purchased power and fuel	8,103	6,967
Purchased power and fuel from affiliates	—	(6)
Operating and maintenance	2,955	3,779
Operating and maintenance from affiliates	458	409
Depreciation and amortization	2,735	1,161
Taxes other than income taxes	354	364
Total operating expenses	14,605	12,674
Gain on sales of assets and businesses	144	12
Operating (loss) income	(344)	610
Other income and (deductions)		
Interest expense, net	(214)	(251)
Interest expense to affiliates	(11)	(26)
Other, net	561	199
Total other income and (deductions)	336	(78)
(Loss) income before income taxes	(8)	532
Income taxes	108	41
Equity in losses of unconsolidated affiliates	(6)	(6)
Net (loss) income	(122)	485
Net income (loss) attributable to noncontrolling interests	125	(85)
Net (loss) income attributable to membership interest	$ (247)	$ 570
Comprehensive income (loss), net of income taxes		
Net (loss) income	$ (122)	$ 485
Other comprehensive (loss) income, net of income taxes		
Unrealized loss on cash flow hedges	(1)	(1)
Unrealized (loss) on foreign currency translation	—	(3)
Other comprehensive (loss), net of income taxes	(1)	(4)
Comprehensive (loss) income	(123)	481
Comprehensive income (loss) attributable to noncontrolling interests	125	(85)
Comprehensive (loss) income attributable to membership interest	$ (248)	$ 566

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Cash flows from operating activities		
Net (loss) income	$ (122)	$ 485
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	3,951	2,266
Asset impairments	537	552
Gain on sales of assets and businesses	(144)	(12)
Deferred income taxes and amortization of investment tax credits	(204)	(51)
Net fair value changes related to derivatives	(1,244)	(448)
Net realized and unrealized gains on NDT funds	(383)	(59)
Net unrealized losses on equity investments	83	—
Other non-cash operating activities	(582)	293
Changes in assets and liabilities:		
Accounts receivable	(207)	1,463
Receivables from and payables to affiliates, net	82	75
Inventories	(29)	(65)
Accounts payable and accrued expenses	357	(619)
Option premiums paid, net	(186)	(131)
Collateral received, net	1,974	640
Income taxes	177	112
Pension and non-pension postretirement benefit contributions	(237)	(249)
Other assets and liabilities	(2,849)	(2,889)
Net cash flows provided by operating activities	974	1,363
Cash flows from investing activities		
Capital expenditures	(1,086)	(1,212)
Proceeds from NDT fund sales	5,766	3,370
Investment in NDT funds	(5,900)	(3,438)
Collection of DPP	3,052	2,518
Proceeds from sales of assets and businesses	802	46
Other investing activities	5	5
Net cash flows provided by investing activities	2,639	1,289
Cash flows from financing activities		
Changes in short-term borrowings	(340)	(280)
Proceeds from short-term borrowings with maturities greater than 90 days	880	500
Issuance of long-term debt	152	2,405
Retirement of long-term debt	(89)	(3,613)
Changes in Exelon intercompany money pool	(285)	—
Acquisition of CENG noncontrolling interest	(885)	—
Distributions to member	(1,373)	(1,406)
Contributions from member	64	64
Other financing activities	(45)	(48)
Net cash flows used in financing activities	(1,921)	(2,378)
Increase in cash, restricted cash, and cash equivalents	1,692	274
Cash, restricted cash, and cash equivalents at beginning of period	327	449
Cash, restricted cash, and cash equivalents at end of period	$ 2,019	$ 723
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (77)	$ (77)
Increase in DPP	2,933	3,275
Increase in PP&E related to ARO update	550	775

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,957	$ 226
Restricted cash and cash equivalents	62	89
Accounts receivable		
Customer accounts receivable	1,412	1,330
Customer allowance for credit losses	(84)	(32)
Customer accounts receivable, net	1,328	1,298
Other accounts receivable	465	352
Other allowance for credit losses	(4)	—
Other accounts receivable, net	461	352
Mark-to-market derivative assets	1,505	644
Receivables from affiliates	184	153
Unamortized energy contract assets	36	38
Inventories, net		
Fossil fuel and emission allowances	240	233
Materials and supplies	998	978
Renewable energy credits	486	621
Assets held for sale	11	958
Other	1,319	1,357
Total current assets	8,587	6,947
Property, plant, and equipment (net of accumulated depreciation and amortization of $15,966 and $13,370 as of September 30, 2021 and December 31, 2020, respectively)	19,574	22,214
Deferred debits and other assets		
Nuclear decommissioning trust funds	15,404	14,464
Investments	165	184
Goodwill	47	47
Mark-to-market derivative assets	664	555
Prepaid pension asset	1,702	1,558
Unamortized energy contract assets	265	293
Deferred income taxes	13	6
Other	1,589	1,826
Total deferred debits and other assets	19,849	18,933
Total assets[(a)]	$48,010	$48,094

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 1,380	$ 840
Long-term debt due within one year	1,216	197
Accounts payable	1,612	1,253
Accrued expenses	691	788
Payables to affiliates	154	107
Borrowings from Exelon intercompany money pool	—	285
Mark-to-market derivative liabilities	1,709	262
Unamortized energy contract liabilities	2	7
Renewable energy credit obligation	682	661
Liabilities held for sale	3	375
Other	347	444
Total current liabilities	7,796	5,219
Long-term debt	4,593	5,566
Long-term debt to affiliates	321	324
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,685	3,656
Asset retirement obligations	12,635	12,054
Non-pension postretirement benefit obligations	857	858
Spent nuclear fuel obligation	1,209	1,208
Payables to affiliates	3,143	3,017
Mark-to-market derivative liabilities	511	205
Unamortized energy contract liabilities	1	3
Other	1,224	1,308
Total deferred credits and other liabilities	23,265	22,309
Total liabilities[(a)]	35,975	33,418
Commitments and contingencies		
Equity		
Member’s equity		
Membership interest	10,480	9,624
Undistributed earnings	1,185	2,805
Accumulated other comprehensive loss, net	(31)	(30)
Total member’s equity	11,634	12,399
Noncontrolling interests	401	2,277
Total equity	12,035	14,676
Total liabilities and equity	$48,010	$48,094

(a) The consolidated assets include $2,704 million and $10,182 million at September 30, 2021 and December 31, 2020, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. The consolidated liabilities include $1,078 million and $3,572 million at September 30, 2021 and December 31, 2020, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 16 — Variable Interest Entities for additional information.

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Unaudited)

	Nine Months Ended September 30, 2021				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2020	$ 9,624	$ 2,805	$(30)	$ 2,277	$14,676
Net (loss) income	—	(247)	—	124	(123)
Changes in equity of noncontrolling interests	—	—	—	(35)	(35)
Acquisition of CENG noncontrolling interest	1,080	—	—	(1,965)	(885)
Deferred tax adjustment related to acquisition of CENG noncontrolling interest	(288)	—	—	—	(288)
Contribution from member	64	—	—	—	64
Distributions to member	—	(1,373)	—	—	(1,373)
Other comprehensive loss, net of income taxes	—	—	(1)	—	(1)
Balance, September 30, 2021	$ 10,480	$ 1,185	$(31)	$ 401	$12,035

	Nine Months Ended September 30, 2020				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2019	$9,566	$ 3,950	$(32)	$2,346	$15,830
Net income (loss)	—	570	—	(85)	485
Changes in equity of noncontrolling interests	—	—	—	(48)	(48)
Sale of noncontrolling interests	3	—	—	—	3
Contribution from member	64	—	—	—	64
Distributions to member	—	(1,406)	—	—	(1,406)
Other comprehensive income, net of income taxes	—	—	(4)	—	(4)
Balance, September 30, 2020	$9,633	$ 3,114	$(36)	$2,213	$14,924

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

1. Significant Accounting Policies

Description of Business

We are a company engaged in the generation, delivery and marketing of power across multiple geographical regions through our customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. We also sell natural gas, renewable energy and other energy-related products and services. We have five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions.

Basis of Presentation

On February 21, 2021, Exelon’s Board of Directors approved a plan to separate Exelon’s utility subsidiaries and Generation, creating two publicly traded companies. Under the separation plan, Exelon shareholders will retain their current shares of Exelon stock and receive a pro-rata distribution of shares of Constellation Energy Corporation stock in a transaction that is expected to be tax-free to Exelon and its shareholders for U.S. federal income tax purposes. The actual number of shares to be distributed to Exelon shareholders will be determined prior to closing.

Exelon is targeting to complete the separation in the first quarter of 2022, subject to final approval by its Board of Directors. The transaction is subject to approval by FERC, NRC and NYPSC and receipt of a private letter ruling from the IRS and tax opinion from Exelon’s tax advisors. There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing.

On February 25, 2021, we filed applications with FERC, NYPSC, and NRC seeking approvals for the separation. On March 25, 2021, Exelon filed a request for a private letter ruling with the IRS to confirm the tax- free treatment of the planned separation, which was received on September 23, 2021. On August 24, 2021, we received approval from FERC. We expect a decision from the NRC in the fourth quarter of 2021 and have requested a decision from the NYPSC before the end of 2021. We cannot predict if the remaining applications will be approved as filed.

There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing.

The accompanying consolidated financial statements as of September 30, 2021 and for the nine months ended September 30, 2021 and 2020 are unaudited but, in the opinion of the management we have included all adjustments that are considered necessary for a fair statement of our financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2020 Consolidated Balance Sheet was derived from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2021. These Consolidated Financial Statements represent Generation’s historical Consolidated Financial Statements presented in Exelon’s combined Form 10-Q for the interim period ended September 30, 2021 filed with the SEC on November 3, 2021. Unless otherwise indicated or the context otherwise requires, references herein to the terms “we,” “us,” and “our” refer to Generation as historically part of consolidated Exelon.

Through its business services subsidiary, BSC, Exelon provides us with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC are directly charged or allocated to us.

2. Mergers, Acquisitions, and Dispositions

CENG Put Option

Prior to August 6, 2021, we owned a 50.01% membership interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

an 82% undivided ownership interest in Nine Mile Point Unit 2. CENG is 100% consolidated in the financial statements. See Note 16 — Variable Interest Entities for additional information.

On April 1, 2014, we entered into various agreements including a NOSA, an amended LLC Operating Agreement, an Employee Matters Agreement, and a Put Option Agreement, among others with EDF. Under the amended LLC Operating Agreement, CENG made a $400 million special distribution to EDF and committed to make preferred distributions to us until we have received aggregate distributions of $400 million plus a return of 8.50% per annum.

Under the terms of the Put Option Agreement, EDF had the option to sell us its 49.99% equity interest in CENG exercisable beginning on January 1, 2016 and thereafter until June 30, 2022.

On November 20, 2019, we received notice of EDF's intention to exercise the put option to sell us its interest in CENG, and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period. The transaction required approval by FERC and the NYPSC, which approvals were received on July 30, 2020 and April 15, 2021, respectively. On August 6, 2021, we entered into a settlement agreement pursuant to which we purchased EDF's equity interest in CENG for a net purchase price of $885 million, which includes, among other things, an adjustment for EDF's share of the balance of the preferred distribution payable to us by CENG. The difference between the net purchase price and EDF's Noncontrolling Interest as of August 6, 2021 was recorded to Membership Interest in the Consolidated Balance Sheet. As a result of the transaction, we recorded deferred tax liabilities of $288 million in membership interest in the Consolidated Balance Sheet. See Note 10 — Income Taxes for additional information.

The following table summarizes the effects of the changes in our ownership interest in CENG in our Member's Equity:

	Nine Months Ended September 30, 2021
Net loss attributable to membership interest	$ (247)
Pre-tax increase in membership interest for purchase of EDF's 49.99% equity interest[(a)]	1,080
Decrease in membership interest due to deferred tax liabilities resulting from purchase of EDF's 49.99% equity interest[(a)]	(288)
Change from net income attributable to membership interest and transfers from noncontrolling interest	$ 545

(a) Represents non-cash activity in our consolidated financial statements.

Agreement for Sale of Our Solar Business

On December 8, 2020, we entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of our solar business, including 360 MW of generation in operation or under construction across more than 600 sites across the United States. We will retain certain solar assets not included in this agreement, primarily Antelope Valley.

Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions which were satisfied in the first quarter of 2021. The sale was completed on March 31, 2021 for a purchase price of $810 million. We received cash proceeds of $675 million, net of $125 million long-term debt assumed by the buyer and certain working capital and other post-closing adjustments. We recognized a pre-tax gain of $68 million which is included in Gain on sales of assets and businesses in the Consolidated Statement of Operations and Comprehensive Income.

See Note 13 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on the SolGen nonrecourse debt included as part of the transaction.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Agreement for Sale of Our Biomass Facility

On April 28, 2021, we entered into a purchase agreement with ReGenerate Energy Holdings, LLC (“ReGenerate”), under which ReGenerate agreed to purchase our interest in the Albany Green Energy biomass facility. As a result, in the second quarter of 2021, we recorded a pre-tax impairment charge of $140 million in Operating and maintenance expense in our Consolidated Statements of Operations and Comprehensive Income. Completion of the transaction was subject to the satisfaction of various customary closing conditions which were satisfied in the second quarter of 2021. The sale was completed on June 30, 2021 for a net purchase price of $36 million.

3. Regulatory Matters

The following matters below discuss the status of our material regulatory and legislative proceedings.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. In response to the high demand and significantly reduced total generation on the system, the PUCT directed ERCOT to use an administrative price cap of $9,000 per MWh during firm load shedding events.

The estimated impact to our Net income for the nine months ended September 30, 2021 arising from these market and weather conditions was a reduction of approximately $880 million. The ultimate impact to the consolidated financial statements for the full year 2021 may be affected by a number of factors, including the impacts of customer and counterparty credit losses, any state or federal solutions to address the financial challenges caused by the event, and related litigation and contract disputes.

During February and March 2021, various parties with differing interests, including generators and retail providers, filed requests with the PUCT to void the PUCT’s orders setting prices at $9,000 per MWh during firm load shedding events. Other requests were made for the PUCT to enforce its order and reduce prices for 33 hours between February 18 and February 19 after firm load shedding ceased, and to cap ancillary services at $9,000 per MWh.

On March 2, 2021, a third party filed a notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT’s actions. We intervened in that appeal and filed our initial brief on June 2, 2021. On April 19, 2021, we filed a declaratory action and request for judicial review of the PUCT’s orders setting prices at $9,000 per MWh in District Court of Travis County, Texas. We subsequently requested that the District Court of Travis County, Texas stay its proceeding pending action by the Court of Appeals in the third party proceeding. On May 17, 2021, we amended our petition for declaratory action and request for judicial review pending in the District Court of Travis County, Texas. We cannot predict the outcome of these proceedings or the financial statement impact.

Due to these events, a number of ERCOT market participants experienced bankruptcies or defaulted on payments to ERCOT, resulting in approximately a $3.0 billion payment shortfall in collections, which is allocated to the remaining ERCOT market participants. As of September 30, 2021, we have recorded our estimated portion of this obligation of approximately $17 million on a discounted basis, which is to be paid over a term of 83 years. ERCOT rules historically have limited recovery of default from market participants to $2.5 million per month market-wide. In February 2021, the PUCT gave ERCOT discretion to disregard those rules, but ERCOT has declined to exercise that discretion thus far. On March 8, 2021, a third party filed a notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT’s order to ERCOT in February 2021. We intervened in that appeal and filed an initial brief on July 7, 2021. On May 7, 2021, we filed a declaratory action and request for judicial review of the PUCT’s order in the District Court of Travis County, Texas. We subsequently requested that the District

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Court of Travis County, Texas stay its proceeding pending action by the Court of Appeals in the third party proceeding. We cannot predict the outcome of these proceedings or the financial statement impact.

Additionally, several legislative proposals were introduced in the Texas legislature during February and March 2021 concerning the amount, timing and allocation of recovery of the $3.0 billion shortfall, as well as recovery of other costs associated with the PUCT’s directive to set prices at $9,000 per MWh. Two of these proposals were enacted into law in June 2021 and establish financing mechanisms that ERCOT and certain market participants can utilize to fund amounts owed to ERCOT. We participated in proceedings before the PUCT addressing the proposed allocation of the $2.1 billion in securitized funds for reliability and ancillary service charges over $9,000/MWh. In September 2021, we entered into a settlement agreement and stipulation to resolve the allocation issues. The PUCT approved the settlement agreement and stipulation on October 13, 2021.

In addition, other legislative proposals were introduced in the Texas legislature during February and March 2021 addressing cold-weather preparation for power plants and natural gas production and transportation infrastructure and the market structure for reliability services. The Texas legislature addressed these proposals by enacting a bill with a broad set of market reforms that, among other things, directed the PUCT to establish weatherization standards for electric generators within six months of enactment and gave the PUCT authority to impose administrative penalties if the new proposed standards, once adopted, are not met. On October 21, 2021, the PUCT adopted a rule change requiring generators by December 1, 2021 to complete a number of specified winter readiness preparations and to submit to ERCOT a report describing and certifying the completion of those preparations. The PUCT described these requirements as the first phase of its actions with respect to winter preparedness, to be followed by a second phase consisting of a year-round set of weather preparedness standards to be informed by a weather study that is being conducted by ERCOT.

The legislation also directs the PUCT to evaluate whether additional ancillary services are needed for reliability in the ERCOT power region to provide adequate incentives for dispatchable generation. We and others have submitted various proposals to the PUCT with respect to a range of potential market reforms, including the implementation of additional ancillary service products as well as changes to the high system-wide offer cap and operating reserve demand curve, which remain pending. On September 23, 2021, the PUCT solicited comments regarding whether it should set ERCOT’s high system-wide offer cap at $4,500/MWh if the PUCT takes action to amend its rules with respect to that cap. We and others submitted comments to the PUCT, which remain pending. The PUCT is expected to address potential changes to ERCOT’s market rules later in 2021.

In February 2021, more than 70 local distribution companies (LDCs) and natural gas pipelines in multiple states throughout the mid-continent region, where we serve natural gas customers, issued operational flow orders (OFOs), curtailments or other limitations on natural gas transportation or use to manage the operational integrity of the applicable LDC or pipeline system. When in effect, gas transportation or use above these limitations is subject to significant penalties according to the applicable LDCs’ and natural gas pipelines’ tariffs. Gas transportation and supply in many states became restricted due to wells freezing and pipeline compression disruption, while demand was increasing due to the extreme cold temperatures, resulting in extremely high natural gas prices. Due to the extraordinary circumstances, many LDCs and natural gas pipelines have either voluntarily waived or have sought applicable regulatory approvals to waive the tariff penalties associated with the extreme weather event. During March 2021, three natural gas pipelines filed individual petitions with FERC requesting approval to waive OFO penalties. We also filed motions in March 2021 to intervene and filed comments in support of these FERC waiver requests. On March 25, 2021, FERC issued an order on one of the petitions approving a pipeline’s request for a limited waiver of penalties for February 15, 2021. On April 23, 2021, we and several other entities filed a request at FERC for rehearing of this order which was denied on May 24, 2021. The other entities including ourselves filed an appeal of the rehearing of the order with the D.C. Circuit on July 21, 2021. Additionally, we and the other entities filed a complaint requesting that FERC expand the order to include additional days of the weather event in February, from February 16 through February 19, 2021. On October 21, 2021, FERC denied the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

complaint finding that a pipeline has the discretion whether to waive penalties under its tariff. We are evaluating whether to seek rehearing and appeal of the FERC order. During April 2021, FERC issued orders on the remaining petitions approving the requests to waive the penalties. During May 2021, an LDC filed a motion with the Kansas Corporation Commission (KCC) requesting the KCC to grant a waiver from the tariff and allow the LDC to reduce the amounts assessed by permitting the removal of a multiplier from the penalty calculation. On October 8, 2021, a settlement was filed with the KCC that, if approved, would resolve this matter. We cannot predict the outcome of the pending FERC complaint proceeding, the KCC proceeding, or the determinations made by the LDCs and natural gas pipelines.

Illinois Regulatory Matters

Clean Energy Law. On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorizes the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. Our Byron, Dresden, and Braidwood nuclear plants located in Illinois will be eligible to participate in the CMC procurement process and, if awarded contracts, would be committed to operate through May 31, 2027. Selected generators will by December 3, 2021 contract directly with ComEd for the procurement of the CMCs based upon the number of MWhs produced annually by the eligible facilities, subject to specified caps and minimum performance requirements. The price to be paid for each CMC will be determined through a competitive bidding process that includes consumer-protection measures that cap the maximum acceptable bid amount and reduce CMC prices by an energy price index, the base residual auction capacity price in the ComEd zone of PJM, and the monetized value of any federal tax credit or other subsidy if applicable. Regulatory or legal challenges regarding the validity or implementation of the Clean Energy Law are possible and we cannot reasonably predict the outcome of any such challenges.

See Note 7 — Early Plant Retirements for the impacts of the provisions above on the Illinois nuclear plants and the consolidated financial statements.

New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that provides 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 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. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. Upon approval, we began recognizing revenue for the sale of New Jersey ZECs in the month they are generated. On March 19, 2021, a three-judge panel of the Superior Court of New Jersey Appellate Division unanimously affirmed the NJBPU's April 2019 order awarding ZECs for the first eligibility period. On April 8, 2021, New Jersey Rate Counsel filed a notice asking the New Jersey Supreme Court to hear the appeal of the Superior Court's order. On July 9, 2021, the New Jersey Supreme Court declined to hear the appeal. On October 1, 2020, we and PSEG filed applications seeking ZECs for the second eligibility period (June 2022 through May 2025). On April 27, 2021, the NJBPU approved the award of ZECs to Salem 1 and Salem 2 for the second eligibility period. On May 11, 2021, the New Jersey Rate Counsel appealed the April 27, 2021 decision to the Superior Court of New Jersey Appellate Division. Briefing on the appeal is expected to conclude in the fourth quarter of 2021 or first quarter of 2022. We cannot predict the outcome of this proceeding.

New England Regulatory Matters

Mystic Units 8 and 9 and Everett Marine Terminal Cost of Service Agreement. On March 29, 2018, we notified grid operator ISO-NE of our plans to early retire Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. On May 16, 2018, we made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 & 9 for the period between June 1, 2022 – May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service compensation, reflecting a number of adjustments to the annual fixed revenue requirement and allowing for recovery of a substantial portion of the costs associated with the adjacent Everett Marine Terminal we acquired in October 2018. Those adjustments were reflected in a compliance filing made on March 1, 2019. In the December 20, 2018 order, FERC also directed a paper hearing on ROE using a new methodology. On January 22, 2019, we and several other parties filed requests for rehearing of certain findings in the order. On July 15, 2021, FERC issued an order establishing the ROE to be used in the cost of service agreement for Mystic 8 and 9 at 9.33%. On August 16, 2021, we and several other parties filed requests for rehearing of certain aspects of the July 15, 2021 order. These requests were denied by operation of law; however, FERC indicated it would address the issues raised in the request in a future order.

On July 17, 2020, FERC issued three orders, which together affirmed the recovery of key elements of Mystic’s cost of service compensation, including recovery of costs associated with the operation of the Everett Marine Terminal. FERC directed a downward adjustment to the rate base for Mystic Units 8 and 9, the effect of which will be partially offset by elimination of a crediting mechanism for third party gas sales during the term of the cost of service agreement. In addition, several parties filed protests to a compliance filing by us on September 15, 2020, taking issue with how gross plant in-service was calculated, and we filed an answer to the protests on October 21, 2020. On December 21, 2020, FERC issued an order on rehearing of the three July 17, 2020 orders, clarifying several cost of service provisions. Several parties appealed the December 21, 2020 order to the U.S. Court of Appeals for the D.C. Circuit and that appeal was consolidated with appeals of orders issued December 20, 2018 and July 17, 2020 in the Mystic proceeding. Briefs in support of their petitions for review were filed by us and several other parties including ourselves on September 7, 2021. Briefing is expected to conclude in February 2022.

On February 25, 2021, Mystic made its filing to comply with the December 21, 2020 order. On April 26, 2021, FERC rejected Mystic’s language and directed another compliance filing relating to the claw back provision language, which only applies if Mystic 8 and 9 were to continue operation after the conclusion of the cost-of-service period. FERC’s April 26, 2021 order also accepted in part and rejected in part Mystic’s September 15, 2020 compliance filing. It directed a further compliance filing in 60 days consistent with the information provided in Mystic’s October 21, 2020 answer to protests, which Mystic filed on June 2, 2021 and FERC accepted on July 29, 2021. On August 16, 2021, Mystic made a compliance filing, reflecting changes to the cost of service agreement to comply with the July 15, 2021 order on ROE.

On August 25, 2020, a group of New England generators filed a complaint against us seeking to extend the scope of the claw back provision in the cost-of-service agreement, whereby we would refund certain amounts recovered during the term of the cost of service if it returns to market afterwards. On April 15, 2021 FERC dismissed the complaint.

On February 16, 2021, we filed an unopposed motion to voluntarily dismiss an appeal filed with the U.S. Court of Appeals for the D.C. Circuit stemming from a June 2020 complaint filed with FERC against ISO-NE over failures to follow its tariff in evaluating Mystic for transmission security for the 2024 to 2025 Capacity Commitment Period, which was granted on February 18, 2021.

See Note 7 — Early Plant Retirements for additional information on the impacts of our August 2020 decision to retire Mystic Units 8 and 9 upon expiration of the cost of service agreement.

Federal Regulatory Matters

PJM and NYISO MOPR Proceedings. PJM and NYISO capacity markets include a MOPR. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a state government-provided financial support program — resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the MOPR in PJM applied only to certain new gas-fired resources. Currently, the MOPR in NYISO applies only to certain resources in downstate New York.

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(Dollars in millions, except per share data unless otherwise noted)

For our nuclear facilities in PJM and NYISO that are currently receiving state-supported compensation for carbon-free attributes, an expanded MOPR would require exclusion of such compensation when bidding into future capacity auctions, resulting in an increased risk of these facilities not receiving capacity revenues in future auctions.

On December 19, 2019, FERC required PJM to broadly apply the MOPR to all new and existing resources including nuclear, renewables, demand response, energy efficiency, storage, and all resources owned by vertically-integrated utilities. This greatly expanded the breadth and scope of PJM’s MOPR, which became effective as of PJM’s capacity auction for the 2022-23 planning year. While FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources.

FERC provided no new mechanism for accommodating state-supported resources other than the existing FRR mechanism (under which an entire utility zone would be removed from PJM’s capacity auction along with sufficient resources to support the load in such zone). In response to FERC’s order, PJM submitted a compliance filing on March 18, 2020 wherein PJM proposed tariff language interpreting and implementing FERC’s directives, and proposed a schedule for resuming capacity auctions that is contingent on the timing of FERC’s action on the compliance filing.

On April 16, 2020, FERC issued an order largely denying most requests for rehearing of FERC’s December 2019 order but granting a few clarifications that required an additional PJM compliance filing which PJM submitted on June 1, 2020.

A number of parties, including us, have filed petitions for review of FERC’s orders in this proceeding, which remain pending before the Court of Appeals for the District of Columbia Circuit.

As a result, the MOPR applied in the capacity auction for the 2022-23 planning year to our owned or jointly owned nuclear plants in those states receiving a benefit under the Illinois ZES and the New Jersey ZEC program. The MOPR prevented Quad Cities from clearing in that capacity auction.

At the direction of the PJM Board of Managers, PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. PJM filed related tariff revisions at FERC on July 30, 2021 and, on September 29, 2021, PJM’s proposed MOPR reforms became effective by operation of law. Under the new tariff provisions, the MOPR will no longer apply to any of our owned or jointly owned nuclear plants. A request for rehearing of FERC’s notice establishing the effective date for PJM’s proposed market reforms was filed on October 5, 2021 and remains pending.

On February 20, 2020, FERC issued an order rejecting requests to expand NYISO’s version of the MOPR (referred to as buyer-side mitigation rules) beyond its current limited applicability to certain resources in downstate. However, on October 14, 2020, two natural gas-fired generators in New York filed a complaint at FERC seeking to expand the MOPR in NYISO to apply to all resources, new and existing, across the entire NYISO market. We are strenuously opposing expansion of FERC’s MOPR policies in the NYISO market. While it is too early in the proceeding to predict its outcome and there are significant differences between the NYISO and PJM markets that would justify a different result, if FERC applies the MOPR in NYISO broadly as requested in the complaint, our facilities in NYISO that are receiving ZEC compensation may be at increased risk of not clearing the capacity auction.

If our state-supported nuclear plants in PJM or NYISO are subjected to the MOPR or equivalent without compensation under an FRR or similar program, it could have a material adverse impact on the financial statements, which we cannot reasonably estimate at this time.

Operating License Renewals

Conowingo Hydroelectric Project. On August 29, 2012, we submitted an application to FERC for a new license for the Conowingo Hydroelectric Project (Conowingo). In connection with our efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act (401 Certification) from

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(Dollars in millions, except per share data unless otherwise noted)

MDE for Conowingo, we had been working with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 27, 2018, MDE issued its 401 Certification for Conowingo. On October 29, 2019, we and MDE filed with FERC a Joint Offer of Settlement (Offer of Settlement) that would resolve all outstanding issues relating to the 401 Certification. Pursuant to the Offer of Settlement, the parties submitted Proposed License Articles to FERC to be incorporated by FERC into the new license in accordance with FERC's discretionary authority under the Federal Power Act.

On March 19, 2021, FERC issued a new 50-year license for Conowingo, effective March 1, 2021. FERC adopted the Proposed License Articles into the new license only making modifications it deemed necessary to allow FERC to enforce the Proposed License Articles. Consistent with the Offer of Settlement, FERC found that MDE waived its 401 Certification. On April 19, 2021, a few environmental groups filed with FERC a petition for rehearing requesting that FERC reconsider the issuance of the new Conowingo license, which was denied by operation of law on May 20, 2021. On June 17, 2021, the petitioners appealed FERC's ruling to the United States Court of Appeals. On July 15, 2021, FERC issued an order addressing the arguments raised on rehearing, affirming the determinations of its March 19, 2021 order. We cannot predict the outcome of this proceeding.

4. Revenue from Contracts with Customers

We recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that we expect to be entitled to in exchange for those goods or services. Our primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services.

See Note 4 — Revenue from Contracts with Customers of the Notes to Audited Consolidated Financial Statements for additional information regarding our primary sources of revenue.

Contract Balances

Contract Assets

We record contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before we have an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. We record contract assets and contract receivables in Other current assets and Customer accounts receivable, net, respectively, in the Consolidated Balance Sheets. The following tables provide a rollforward of the contract assets reflected in the Consolidated Balance Sheets for the nine months ended September 30, 2021 and 2020.

	Contract Assets
Balance as of December 31, 2020	$144
Amounts reclassified to receivables	(43)
Revenues recognized	36
Amounts previously held-for-sale	12
Balance as of September 30, 2021	$149

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	Contract Assets
Balance as of December 31, 2019	$174
Amounts reclassified to receivables	(63)
Revenues recognized	49
Balance as of September 30, 2020	$160

Contract Liabilities

We record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. We record contract liabilities in Other current liabilities and Other noncurrent liabilities in the Consolidated Balance Sheets. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans and the Illinois ZEC program that introduces a cap on the total consideration to be received by us. The following tables provide a rollforward of the contract liabilities reflected in the Consolidated Balance Sheets for the nine months ended September 30, 2021 and 2020.

	Contract Liabilities
Balance as of December 31, 2020	$ 84
Consideration received or due	163
Revenues recognized	(197)
Amounts previously held-for-sale	3
Balance as of September 30, 2021	$ 53

	Contract Liabilities
Balance as of December 31, 2019	$ 71
Consideration received or due	183
Revenues recognized	(198)
Balance as of September 30, 2020	$ 56

The following table reflects revenues recognized in the nine months ended September 30, 2021 and 2020, which were included in contract liabilities at December 31, 2020 and 2019, respectively:

	Nine Months Ended September 30,	
	2021	2020
Revenues recognized	$81	$63

Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of September 30, 2021. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years. This disclosure excludes our power and gas sales contracts as they contain variable volumes and/or variable pricing.

	2021	2022	2023	2024	2025 and thereafter	Total
Remaining performance obligations	$168	$281	$92	$41	$97	$679

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Revenue Disaggregation

We disaggregate revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 5 — Segment Information for the presentation of revenue disaggregation.

5. Segment Information

Operating segments are determined based on information used by the CODM in deciding how to evaluate performance and allocate resources.

We have five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and all other power regions referred to collectively as “Other Power Regions.”

The basis for our reportable segments is the integrated management of our 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). Our hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of our five 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 and the United States footprint of MISO, excluding MISO’s Southern Region.
- **New York** represents operations within NYISO.
- **ERCOT** represents operations within Electric Reliability Council of Texas.
- **Other Power Regions:**
- **New England** represents the operations within ISO-NE.
- **South** represents operations in the FRCC, MISO’s Southern Region, and the remaining portions of the SERC not included within MISO or PJM.
- **West** represents operations in the WECC, which includes CAISO.
- **Canada** represents operations across the entire country of Canada and includes AESO, OIESO, and the Canadian portion of MISO.

The CODM evaluates the performance of our electric business activities and allocates resources based on Revenues Net of Purchased Power and Fuel Expense (RNF). We believe that RNF is a useful measurement of operational performance. RNF 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. Our operating revenues include all sales to third parties and affiliated sales to Exelon’s utility subsidiaries. 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 our owned generation and fuel costs associated with tolling agreements. The results of our other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to our overall operating revenues or results of operations.

Further, our unrealized mark-to-market gains and losses on economic hedging activities and our amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. We

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do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

The following tables disaggregate the revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. The disaggregation of revenues reflects our two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. The following tables also show the reconciliation of reportable segment revenues and RNF to our total revenues and RNF.

	Nine Months Ended September 30, 2021				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 3,377	$ 134	$ 3,511	$ 16	$ 3,527
Midwest	3,067	(123)	2,944	1	2,945
New York	1,204	(30)	1,174	(1)	1,173
ERCOT	724	155	879	11	890
Other Power Regions	3,043	713	3,756	(27)	3,729
Total Competitive Businesses Electric Revenues	$11,415	$ 849	$12,264	$ —	$12,264
Competitive Businesses Natural Gas Revenues	1,384	1,024	2,408	—	2,408
Competitive Businesses Other Revenues[c]	291	(846)	(555)	—	(555)
Total Consolidated Operating Revenues	$13,090	$1,027	$14,117	$ —	$14,117

	Nine Months Ended September 30, 2020				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 3,692	$ (152)	$ 3,540	$ 21	$ 3,561
Midwest	2,773	240	3,013	(6)	3,007
New York	1,074	(12)	1,062	(1)	1,061
ERCOT	579	155	734	20	754
Other Power Regions	2,718	300	3,018	(34)	2,984
Total Competitive Businesses Electric Revenues	$10,836	$ 531	$11,367	$ —	$11,367
Competitive Businesses Natural Gas Revenues	881	467	1,348	—	1,348
Competitive Businesses Other Revenues[c]	268	289	557	—	557
Total Consolidated Operating Revenues	$11,985	$1,287	$13,272	$ —	$13,272

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to Exelon’s utility subsidiaries.

(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 unrealized mark-to-market losses of $958 million and gains of $238 million in 2021 and 2020, respectively, and elimination of intersegment revenues.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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	Nine Months Ended September 30, 2021			Nine Months Ended September 30, 2020		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$1,698	$ 14	$1,712	$1,660	$ 23	$1,683
Midwest	2,014	1	2,015	2,180	(2)	2,178
New York	873	7	880	714	11	725
ERCOT	(775)	(147)	(922)	311	14	325
Other Power Regions	641	(77)	564	608	(70)	538
Total RNF for Reportable Segments	$4,451	$(202)	$4,249	$5,473	$(24)	$5,449
Other(b)	1,563	202	1,765	838	24	862
Total Generation RNF	$6,014	$ —	$6,014	$6,311	$ —	$6,311

(a) Includes purchases and sales from/to third parties and affiliated sales to Exelon's utility subsidiaries.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Primarily includes:

- unrealized mark-to-market gains of $1,242 million and gains of $472 million in 2021 and 2020, respectively;
- accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 7 — Early Plant Retirements of $148 million and $24 million in 2021 and 2020 respectively; and
- the elimination of intersegment RNF.

6. Accounts Receivable

Allowance for Credit Losses on Accounts Receivable

The following tables present the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	Nine Months Ended September 30, 2021
Balance as of December 31, 2020	$32
Plus: Current period provision for expected credit losses(b)	57
Less: Write-offs, net of recoveries(a)	5
Less: Sale of customer accounts receivable(c)	56
Balance as of September 30, 2021	$84

	Nine Months Ended September 30, 2020
Balance as of December 31, 2019	$80
Plus: Current period provision for expected credit losses	13
Less: Write-offs, net of recoveries(a)	4
Less: Sale of customer accounts receivable(c)	56
Balance as of September 30, 2020	$33

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(a) Recoveries were not material.

(b) Primarily relates to the impacts of the February 2021 extreme cold weather event. See Note 3 — Regulatory Matters for additional information.

(c) See below for additional information on the sale of customer accounts receivable in the second quarter of 2020.

Unbilled Customer Revenue

We recorded $359 million and $258 million of unbilled customer revenues in Customer accounts receivables, net in the Consolidated Balance Sheets as of September 30, 2021 and December 31, 2020, respectively.

Sales of Customer Accounts Receivable

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly-owned by us, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivable (the Facility). The Facility had a maximum funding limit of $750 million and was scheduled to expire on April 7, 2021, unless renewed by the mutual consent of the parties in accordance with its terms. The Facility was renewed on March 29, 2021. The Facility term was extended through March 29, 2024, unless further renewed by the mutual consent of the parties, and the maximum funding limit was increased to $900 million. Under the Facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in the consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the DPP, which is reflected in Other current assets in the Consolidated Balance Sheets.

The Facility requires the balance of eligible receivables to be maintained at or above the balance of cash proceeds received from the Purchasers. To the extent the eligible receivables decrease below such balance, we are required to repay cash to the Purchasers. When eligible receivables exceed cash proceeds, we have the ability to increase the cash received up to the maximum funding limit. These cash inflows and outflows impact the DPP.

On April 8, 2020, we derecognized and transferred approximately $1.2 billion of receivables at fair value to the Purchasers in exchange for approximately $500 million in cash purchase price and $650 million of DPP.

During the first quarter of 2021, we received additional cash of $250 million from the Purchasers for the remaining available funding in the Facility.

Additionally, during the first quarter of 2021, we received cash of approximately $150 million from the Purchasers in connection with the increased funding limit at the time of the Facility renewal.

During the second quarter of 2021, we returned cash of $50 million to the Purchasers due to the eligible receivables decreasing temporarily. Subsequently, in the second quarter, we received cash of $50 million from the Purchasers as a result of an increase in the eligible receivable balance. The $50 million cash outflow and inflow is included in the Collection of DPP line in Cash flows from investing activities in the Consolidated Statement of Cash Flows.

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The following table summarizes the impact of the sale of certain receivables:

	September 30, 2021	December 31, 2020
Derecognized receivables transferred at fair value	$1,401	$1,139
Cash proceeds received	900	500
DPP	501	639

	Nine Months Ended September 30,	
	2021	2020
Loss on sale of receivables[(a)]	$26	$23

(a) Reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

	Nine Months Ended September 30,	
	2021	2020
Proceeds from new transfers[(a)]	$4,440	$1,889
Cash collections received on DPP and reinvested in the Facility[(b)]	2,652	2,518
Cash collections reinvested in the Facility	7,092	4,407

(a) Customer accounts receivable sold into the Facility were $7,373 million and $4,515 million for the nine months ended September 30, 2021 and September 30, 2020, respectively

(b) Does not include the $400 million in cash proceeds received from the Purchasers in the first quarter of 2021.

Our risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred, which have historically been and are expected to be immaterial. We continue to service the receivables sold in exchange for a servicing fee. We did not record a servicing asset or liability as the servicing fees were immaterial.

We recognize the cash proceeds received upon sale in Net cash provided by operating activities in the Consolidated Statements of Cash Flows. The collection and reinvestment of DPP is recognized in Net cash provided by investing activities in the Consolidated Statements of Cash Flows.

See Note 14 — Fair Value of Financial Assets and Liabilities and Note 16 — Variable Interest Entities for additional information.

Other Purchases and Sales of Customer and Other Accounts Receivables

We are required, under supplier tariffs in ISO-NE, MISO, NYISO, and PJM, to sell customer and other receivables to utility companies, which include Exelon’s utility subsidiaries. The following table presents the total receivables sold.

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	Nine Months Ended September 30,	
	2021	2020
Total receivables sold	$117	$790
Related party transactions:		
Receivables sold to Exelon's utility subsidiaries	17	248

7. Early Plant Retirements

We continuously evaluate factors that affect the current and expected economic value of our plants, including, but not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for benefits they provide through their carbon-free emissions, reliability, or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and NDT fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

On August 27, 2020, we announced our intention to permanently cease our operations at Byron in September 2021 and at Dresden in November 2021. Neither of these nuclear plants cleared in PJM's capacity auction for the 2022-2023 planning year held in May 2021. Our Braidwood and LaSalle nuclear plants in Illinois did clear in the capacity auction, but were also showing increased signs of economic distress.

On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. Among other things, the Clean Energy Law authorizes the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. Our Byron, Dresden, and Braidwood nuclear plants located in Illinois will be eligible to participate in the CMC procurement process and, if awarded contracts, would be committed to operate through May 31, 2027. See Note 3 — Regulatory Matters for additional information. Following enactment of the legislation, we announced on September 15, 2021, that we have reversed our previous decision to retire Byron and Dresden given the opportunity for additional revenue under the Clean Energy Law. In addition, we no longer consider the Braidwood or LaSalle nuclear plants to be at risk for premature retirement.

As a result of the decision to early retire Byron and Dresden, we recognized certain one-time charges in the third and fourth quarters of 2020 related to materials and supplies inventory reserve adjustments, employee-related costs including severance benefit costs, and construction work-in-progress impairments, among other items. In addition, there were ongoing annual financial impacts stemming from shortening the expected economic useful lives of these nuclear plants primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and changes in ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date.

In the third quarter of 2021, we reversed $81 million of severance benefit costs and $13 million of other one-time charges initially recorded in Operating and maintenance expense in the third and fourth quarters of 2020 associated with the early retirements. In addition, we updated the expected economic useful life for both facilities to 2044 and 2046 for Byron Units 1 and 2, respectively, and to 2029 and 2031 for

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Dresden Units 2 and 3, respectively, the end of the respective NRC operating license for each unit. Depreciation was therefore adjusted beginning September 15, 2021, to reflect these extended useful life estimates. See Note 8 — Nuclear Decommissioning for additional detail on changes to the nuclear decommissioning ARO balances resulting from the initial decision and subsequent reversal of the decision to early retire Byron and Dresden.

The total impact for the nine months ended September 30, 2021 and 2020 in the Consolidated Statements of Operations and Comprehensive Income resulting from the initial decision and subsequent reversal of the decision to early retire Byron and Dresden is summarized in the table below.

Income statement expense (pre-tax)	Nine Months Ended September 30, 2021	2020
Depreciation and amortization		
Accelerated depreciation[a]	$1,805	$ 254
Accelerated nuclear fuel amortization	148	14
Operating and maintenance		
One-time charges	(94)	220
Other charges	8	34
Contractual offset[b]	(451)	(129)
Total	$1,416	$ 393

(a) Includes the accelerated depreciation of plant assets including any ARC.

(b) Reflects contractual offset for ARO accretion and ARC depreciation and excludes any changes in earnings in the NDT funds. Decommissioning-related impacts were not offset for the Byron units starting in the second quarter of 2021 due to the inability to recognize a regulatory asset at ComEd. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. Based on the regulatory agreement with the ICC, decommissioning-related activities are offset in the Consolidated Statements of Operations and Comprehensive Income as long as the net cumulative decommissioning-related activity result in a regulatory liability at ComEd. The offset resulted in an equal adjustment to the noncurrent payables to ComEd. See Note 8 — Nuclear Decommissioning for additional information.

We remain committed to continued operations for our other nuclear plants receiving state-supported payments under the Illinois ZES (Clinton and Quad Cities), New Jersey ZEC program (Salem), and the New York CES (FitzPatrick, Ginna, and Nine Mile Point) assuming the continued effectiveness of such programs. To the extent such programs do not operate as expected over their full terms, each of these plants would be at heightened risk for early retirement, which could have a material impact on the future financial statements. See Note 3 — Regulatory Matters for additional information on the New Jersey ZEC program and Note 3 — Regulatory Matters of the Notes to Audited Consolidated Financial Statements for additional information on the Illinois ZES and New York CES.

We continue to work with stakeholders on state policy solutions to support continued operation of our nuclear fleet, while also advocating for broader market reforms at the regional and federal level. The absence of such solutions or reforms could have a material unfavorable impact on our future results of operations.

Other Generation

In March 2018, we notified ISO-NE of our plans to early retire, among other assets, the Mystic Generating Station’s units 8 and 9 (Mystic 8 and 9) absent regulatory reforms to properly value reliability and regional fuel security. Thereafter, ISO-NE identified Mystic 8 and 9 as being needed to ensure fuel

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security for the region and entered into a cost of service agreement with these two units for the period between June 1, 2022 – May 31, 2024. The agreement was approved by FERC in December 2018.

On June 10, 2020, we filed a complaint with FERC against ISO-NE stating that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic 8 and 9 for transmission security for the 2024 to 2025 Capacity Commitment Period and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic 8 and 9 should have been filed with FERC for approval. On August 17, 2020, FERC issued an order denying the complaint. As a result, on August 20, 2020, we determined we will permanently cease generation operations at Mystic 8 and 9 at the expiration of the cost of service commitment in May 2024. See Note 3 — Regulatory Matters for additional discussion of Mystic's cost of service agreement.

As a result of the decision to early retire Mystic 8 and 9, we recognized $43 million in the third quarter of 2020 of one-time charges related to an expected long-term contract termination and materials and supplies reserve adjustments, among other items. In addition, there are financial impacts stemming from shortening the expected economic useful life of Mystic 8 and 9 primarily related to accelerated depreciation of plant assets. We recorded incremental Depreciation and amortization of $41 million and $6 million for the nine months ended September 30, 2021 and 2020, respectively.

8. Nuclear Decommissioning

Nuclear Decommissioning Asset Retirement Obligations

We have a legal obligation to decommission our nuclear power plants following the expiration of our operating licenses. To estimate our decommissioning obligation related to our nuclear generating stations for financial accounting and reporting purposes, we use a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models, and discount rates. We update our ARO annually, unless circumstances warrant more frequent updates, based on our review of updated cost studies and our annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The financial statement impact for changes in the ARO, on an individual unit basis, due to the changes in and timing of estimated cash flows generally result in a corresponding change in the unit's ARC in Property, plant, and equipment in the Consolidated Balance Sheets. If the ARO decreases for a Non-Regulatory Agreement unit without any remaining ARC, the corresponding change is recorded as decrease in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

The following table provides a rollforward of the nuclear decommissioning ARO reflected in the Consolidated Balance Sheets from December 31, 2020 to September 30, 2021:

Nuclear decommissioning ARO at December 31, 2020[a]	$11,922
Accretion expense	375
Net increase due to changes in, and timing of, estimated future cash flows	256
Costs incurred related to decommissioning plants	(57)
Nuclear decommissioning ARO at September 30, 2021[a]	$12,496

(a) Includes $74 million and $80 million as the current portion of the ARO at September 30, 2021 and December 31, 2020, which is included in Other current liabilities in the Consolidated Balance Sheets.

During the nine months ended September 30, 2021, the net $256 million increase in the ARO for the changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments. These adjustments primarily include:

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- An increase of approximately $510 million for updated cost escalation rates, primarily for labor and energy, and a decrease in discount rates.
- A net decrease of approximately $170 million was driven by updates to Byron and Dresden reflecting changes in assumed retirement dates and assumed methods of decommissioning as a result of the reversal of the decision to early retire the plants. See Note 7 — Early Plant Retirements for additional information.
- A net decrease of approximately $110 million due to lower estimated costs to decommission Byron, Braidwood, Dresden, LaSalle, and Zion nuclear units resulting from the completion of updated cost studies.

The 2021 ARO updates resulted in a decrease of $51 million in Operating and maintenance expense for the nine months ended September 30, 2021 in the Consolidated Statements of Operations and Comprehensive Income.

NDT Funds

We had NDT funds totaling $15,602 million and $14,599 million at September 30, 2021 and December 31, 2020, respectively. The NDT funds also include $198 million and $134 million for the current portion of the NDT funds at September 30, 2021 and December 31, 2020, respectively, which are included in Other current assets in the Consolidated Balance Sheets. See Note 17 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreements with the ICC and PAPUC that dictate our obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis and the former PECO units in total, decommissioning-related activities net of applicable taxes, including realized and unrealized gains and losses on the NDT funds, depreciation of the ARC, and accretion of the decommissioning obligation, are generally offset in the Consolidated Statements of Operations and Comprehensive Income and are recorded as a component of the intercompany and regulatory balances in the balance sheet. For the purposes of making this determination, the decommissioning obligation referred to is different from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

For the former ComEd units, given no further recovery from ComEd customers is permitted and we retain an obligation to ultimately return any unused NDTs to ComEd customers (on a unit-by-unit basis), to the extent the related NDT investment balances are expected to exceed the total estimated decommissioning obligation for each unit, the offset of decommissioning-related activities in the Consolidated Statements of Operations and Comprehensive Income results in us recognizing a noncurrent payable to affiliates. However, given the asymmetric settlement provision that does not allow for continued recovery from ComEd customers in the event of a shortfall, recognition of a regulatory asset at ComEd is not permissible and accounting for decommissioning-related activities for that unit would not be offset, and the impact to the Consolidated Statements of Operations and Comprehensive Income could be material during such periods. During the second and third quarter of 2021, a pre-tax charge of $53 million and $140 million, respectively, was recorded in the Consolidated Statements of Operations and Comprehensive Income for decommissioning-related activities that were not offset for the Byron units due to contractual offset being temporarily suspended. With our September 15, 2021 reversal of the previous decision to retire Byron and the corresponding adjustment to the ARO for Byron discussed previously, we resumed contractual offset for Byron as of that date.

As of September 30, 2021, decommissioning-related activities for all of the former ComEd units, except for Zion, are currently offset in the Consolidated Statements of Operations and Comprehensive Income.

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The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in the Consolidated Statements of Operations and Comprehensive Income.

See Note 10 — Asset Retirement Obligations of the Notes to Audited Consolidated Financial Statements for additional information.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life.

We filed our biennial decommissioning funding status report with the NRC on February 24, 2021 for all units, including its shutdown units, except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions, LLC. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2020 for all units except for Byron Units 1 and 2. We filed an updated decommissioning funding status report for Byron Units 1 and 2 and Dresden Units 2 and 3 on September 28, 2021 based on their current license expiration dates consistent with our announcements regarding the continued operations of these units. This report demonstrated adequate decommissioning funding assurance as of December 31, 2020 for Byron Units 1 and 2 and Dresden Units 2 and 3.

We will file our next decommissioning funding status report with the NRC by March 31, 2022. This report will reflect the status of decommissioning funding assurance as of December 31, 2021 for shutdown units.

9. Asset Impairments

We evaluate the carrying value of long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. We determine if long-lived assets or asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value analysis is primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures, and discount rates. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could potentially result in material future impairments of our long-lived assets.

New England Asset Group

In the third quarter of 2020, in conjunction with the retirement announcement of Mystic Units 8 and 9, we completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the estimated undiscounted future cash flows and fair value of the New England asset group were less than their carrying values. As a result, a pre-tax impairment charge of $500 million was recorded in the third quarter of 2020 in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income. See Note 7 — Early Plant Retirements for additional information.

In the second quarter of 2021, an overall decline in the asset group's portfolio value suggested that the carrying value of the New England asset group may be impaired. We completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the carrying value was not recoverable and that its fair value was less than its carrying value. As a result, a pre-tax

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impairment charge of $350 million was recorded in the second quarter of 2021 in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

Contracted Wind Project

In the third quarter of 2021, significant long-term operational issues anticipated for a specific wind turbine technology suggested that the carrying value of a contracted wind asset, located in Maryland and part of the EGRP joint venture, may be impaired. We completed a comprehensive review of the estimated undiscounted future cash flows and concluded that the carrying value of this contracted wind project was not recoverable and that its fair value was less than its carrying value. As a result, in the third quarter of 2021, a pre-tax impairment charge of $45 million was recorded in Operating and maintenance expense, $21 million of which was offset in Net income attributable to noncontrolling interests in the Consolidated Statements of Operations and Comprehensive Income.

10. Income Taxes

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. federal statutory rate principally due to the following:

	Nine Months Ended September 30,	
	2021[a][b]	2020[a]
U.S. Federal statutory rate	21.0%	21.0%
Increase (decrease) due to:		
State income taxes, net of Federal income tax benefit	90.2	—
Qualified NDT fund income	(1,932.6)	10.0
Amortization of investment tax credit, including deferred taxes on basis difference	130.6	(3.2)
Production tax credits and other credits	425.1	(7.0)
Noncontrolling interests	145.2	3.1
Tax settlements[c]	—	(15.7)
Other	(229.5)	(0.5)
Effective income tax rate	(1,350.0)%	7.7%

(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.

(b) We recognized a loss before income taxes for the nine months ended September 30, 2021. As a result, a negative percentage represents an income tax expense for the period presented.

(c) Our unrecognized federal and state tax benefits decreased in the first quarter of 2020 by approximately $411 million due to the settlement of a federal refund claim with IRS Appeals. The recognition of these tax benefits resulted in an increase to our net income of $73 million in the first quarter of 2020, reflecting a decrease to our income tax expense of $67 million.

Unrecognized Tax Benefits

Our unrecognized tax benefit as of September 30, 2021 and December 31, 2020 are not material.

Other Income Tax Matters

CENG Put Option

On August 6, 2021, we entered into a settlement agreement with EDF pursuant to which we purchased EDF's equity interest in CENG. We recorded a deferred tax liability of $288 million against Membership Interest in the Consolidated Balance Sheet. The deferred tax liability represents the tax effect on the difference between the net purchase price and EDF's noncontrolling interest as of August 6, 2021. The deferred tax liabilities will reverse during the remaining operating lives and during decommissioning of the CENG nuclear plants. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

Long-Term Marginal State Income Tax Rate

In the third quarter of 2021 and 2020, we updated our marginal state income tax rates for changes in state apportionment. The changes in marginal rates in the third quarter of 2021 resulted in no change to our deferred income tax liability as of September 30, 2021. The changes in marginal rates in the third quarter of 2020 resulted in a decrease of $26 million to our deferred income tax liability and a corresponding adjustment to income tax expense, net of federal taxes.

Allocation of Tax Benefits

We are a party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the parties. That allocation is treated as a contribution to the capital of the party receiving the benefit. The allocation of federal tax benefits from Exelon to us under the Tax Sharing Agreement was $64 million for the nine months ended September 30, 2021 and 2020.

11. Retirement Benefits

Defined Benefit Pension and OPEB

Exelon sponsors defined benefit pension plans and OPEB plans for essentially all our current employees. We account for our participation in Exelon's pension and OPEB plans by applying multi-employer accounting. Exelon allocates costs related to its pension and OPEB plans to its subsidiaries based on both active and retired employee participation in each plan.

We were allocated pension and OPEB costs of $92 million and $89 million for the nine months ended September 30, 2021 and 2020, respectively. We include the service cost and non-service cost components in Operating and maintenance expense and Property, plant, and equipment, net in the consolidated financial statements.

Defined Contribution Savings Plans

We participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. We match a percentage of the employee contributions up to certain limits. The matching contributions to the savings plans were $40 million and $41 million for the nine months ended September 30, 2021 and 2020, respectively.

12. Derivative Financial Instruments

We use derivative instruments to manage commodity price risk, interest rate risk, and foreign exchange risk related to ongoing business operations.

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Authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include NPNS, cash flow hedges, and fair value hedges. All derivative economic hedges related to commodities, referred to as economic hedges, are recorded at fair value through earnings. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below, which present fair value balances, our energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

Our use of cash collateral is generally unrestricted unless we are downgraded below investment grade.

Commodity Price Risk

We employ established policies and procedures to manage our risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and commodity products. We believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

To the extent the amount of energy we produce differs from the amount of energy it has contracted to sell, we are exposed to market fluctuations in the prices of electricity, fossil fuels, and other commodities. We use a variety of derivative and non-derivative instruments to manage the commodity price risk of our electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. We are also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

Additionally, we are exposed to certain market risks through our proprietary trading activities. The proprietary trading activities are a complement to our energy marketing portfolio but represent a small portion of our overall energy marketing activities and are subject to limits established by the RMC.

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The following tables provide a summary of the derivative fair value balances recorded as of September 30, 2021 and December 31, 2020:

September 30, 2021	Economic Hedges	Proprietary Trading	Collateral[a][b]	Netting[a]	Subtotal
Mark-to-market derivative assets (current assets)	$ 19,631	$ 63	$ (790)	$(17,399)	$ 1,505
Mark-to-market derivative assets (noncurrent assets)	3,612	5	(201)	(2,755)	661
Total mark-to-market derivative assets	23,243	68	(991)	(20,154)	2,166
Mark-to-market derivative liabilities (current liabilities)	(18,490)	(55)	(559)	17,399	(1,705)
Mark-to-market derivative liabilities (noncurrent liabilities)	(3,168)	(3)	(95)	2,755	(511)
Total mark-to-market derivative liabilities	(21,658)	(58)	(654)	20,154	(2,216)
Total mark-to-market derivative net assets (liabilities)	$ 1,585	$ 10	$(1,645)	$ —	$ (50)

December 31, 2020	Economic Hedges	Proprietary Trading	Collateral[a][b]	Netting[a]	Subtotal
Mark-to-market derivative assets (current assets)	$ 2,757	$ 40	$103	$(2,261)	$ 639
Mark-to-market derivative assets (noncurrent assets)	1,501	4	64	(1,015)	554
Total mark-to-market derivative assets	4,258	44	167	(3,276)	1,193
Mark-to-market derivative liabilities (current liabilities)	(2,629)	(23)	131	2,261	(260)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,335)	(2)	118	1,015	(204)
Total mark-to-market derivative liabilities	(3,964)	(25)	249	3,276	(464)
Total mark-to-market derivative net assets	$ 294	$ 19	$416	$ —	$ 729

(a) We net all available amounts allowed under the derivative authoritative guidance in the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases we may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit, and other forms of non-cash collateral. As of September 30, 2021, $1 million of cash collateral posted with external counterparties and an additional $71 million of cash collateral posted with affiliates, and as of December 31, 2020, $15 million of cash collateral held with external counterparties, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, was associated with accrual positions, or had no positions to offset as of the balance sheet date.

(b) Includes $2,084 million held and $209 million posted of variation margin with the exchanges as of September 30, 2021 and December 31, 2020, respectively.

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Economic Hedges (Commodity Price Risk)

For the nine months ended September 30, 2021 and 2020, we recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

	Nine Months Ended September 30,	
	2021	2020
Income Statement Location	(Loss) Gain	
Operating revenues	$ (961)	$238
Purchased power and fuel	2,209	224
Total	$1,248	$462

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on owned and contracted generation positions that have not been hedged. We hedge commodity price risk on a ratable basis over three-year periods. As of September 30, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 96%-99% for the remainder of 2021.

Proprietary Trading (Commodity Price Risk)

We also execute commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Gains and losses associated with proprietary trading are reported as Operating revenues in the Consolidated Statements of Operations and Comprehensive Income and are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows. For the nine months ended September 30, 2021 and 2020, net pre-tax commodity mark-to-market gains and losses were not material.

Interest Rate and Foreign Exchange Risk

We utilize interest rate swaps to manage our interest rate exposure and foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, both of which are treated as economic hedges. The notional amounts were $567 million and $665 million as of September 30, 2021 and December 31, 2020, respectively.

The mark-to-market derivative assets and liabilities as of September 30, 2021 and December 31, 2020 and the mark-to-market gains and losses for the nine months ended September 30, 2021 and 2020 were not material**.**

Credit Risk

We would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date.

For commodity derivatives, we enter into enabling agreements that allow for payment netting with its counterparties, which reduces our exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, our credit department establishes credit limits, margining thresholds, and collateral

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requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with us as specified in each enabling agreement. Our credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on the credit exposure for all derivative instruments, NPNS, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The amounts in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

Rating as of September 30, 2021	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counter parties Greater than 10% of Net Exposure	Net Exposureof Counter parties Greater than10% of Net Exposure
Investment grade	$ 701	$254	$447	—	$ —
Non-investment grade	23	2	21		
No external ratings				—	—
Internally rated – investment grade	110	1	109	—	—
Internally rated – non-investment grade	309	48	261	—	—
Total	$1,143	$305	$838	—	$ —

Net Credit Exposure by Type of Counterparty	As of September 30, 2021
Financial institutions	$ 53
Investor-owned utilities, marketers, power producers	652
Energy cooperatives and municipalities	62
Other	71
Total	$838

(a) As of September 30, 2021, credit collateral held from counterparties where we had credit exposure included $188 million of cash and $117 million of letters of credit. The credit collateral does not include non-liquid collateral.

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of our derivative instruments contain provisions that require us to post collateral. We also enter into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon our credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features

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stipulate that if we were to be downgraded or lose our investment grade credit rating (based on our senior unsecured debt rating), we would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, we believe an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Features	September 30, 2021	December 31, 2020
Gross fair value of derivative contracts containing this feature[(a)]	$(5,289)	$(834)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	2,735	537
Net fair value of derivative contracts containing this feature[(c)]	$(2,554)	$(297)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk related contingent features ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which we could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

As of September 30, 2021 and December 31, 2020, we posted or held the following amounts of cash collateral and letters of credit on derivative contracts with external counterparties, after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

	September 30, 2021	December 31, 2020
Cash collateral posted	$ 299	$ 511
Letters of credit posted	477	226
Cash collateral held	1,872	110
Letters of credit held	130	40
Additional collateral required in the event of a credit downgrade below investment grade	3,001	1,432

We entered into supply forward contracts with certain utilities with one-sided collateral postings only from us. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including us, are required to post collateral once certain unsecured credit limits are exceeded.

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13. Debt and Credit Agreements

Short-Term Borrowings

We meet our short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. We may use our respective credit facility for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects our commercial paper program as of September 30, 2021 and December 31, 2020.

Outstanding Commercial Paper as of		Average Interest Rate on Commercial Paper Borrowings as of	
September 30, 2021	December 31, 2020	September 30, 2021	December 31, 2020
—	340	—%	0.27%

See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on our credit facility.

Short-Term Loan Agreements

On March 19, 2020, we entered into a term loan agreement for $200 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.875% and all indebtedness thereunder is unsecured.

On March 31, 2020, we entered into a term loan agreement for $300 million. The loan agreement was renewed on March 30, 2021 and will expire on March 29, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.70% and all indebtedness thereunder is unsecured.

On August 6, 2021, we entered into a 364-day term loan agreement for $880 million with a variable interest rate of LIBOR plus 0.875% until March 31, 2022 and a rate of LIBOR plus 1% thereafter and all indebtedness thereunder is unsecured. The loan agreement has an expiration date of August 5, 2022.

These loan agreements are reflected in Short-term borrowings in the Consolidated Balance Sheet.

Bilateral Credit Agreements

On January 11, 2013, we entered into a bilateral credit agreement for $100 million. The agreement was renewed on March 1, 2021 with a maturity date of March 1, 2023.

On February 21, 2019, we entered into a bilateral credit agreement for $100 million. The agreement was renewed on March 31, 2021 with a maturity date of March 31, 2022.

On January 5, 2016, we entered into a bilateral credit agreement for $150 million. The agreement was renewed on April 2, 2021 with a maturity date of April 5, 2023.

On October 26, 2012, we entered into a bilateral credit agreement for $200 million. The agreement had a maturity date of October 22, 2021, however, was terminated on August 27, 2021.

See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on our bilateral credit agreements.

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Credit Agreements

On July 15, 2021, our syndicated revolving credit facility had the maturity date extended to May 26, 2024.

Long-Term Debt

Issuance of Long-Term Debt

During the nine months ended September 30, 2021, we issued the following long-term debt:

Type	Interest Rate	Maturity	Amount	Use of Proceeds
West Medway II Nonrecourse Debt	LIBOR + 3%[a]	March 31, 2026	150	Funding for general corporate purposes.
Energy Efficiency Project Financing[b]	2.53%	November 30, 2021	1	Funding to install energy conservation measures for the Fort AP Hill project.
Energy Efficiency Project Financing[b]	4.24%	November 30, 2021	1	Funding to install energy conservation measures for the Marine Corps. Logistics Project.

(a) The nonrecourse debt has an average blended interest rate.

(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

Debt Covenants

As of September 30, 2021, we are in compliance with debt covenants.

Nonrecourse Debt

We have issued nonrecourse debt financing. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against us in the event of a default.

West Medway II, LLC. On May 13, 2021, West Medway II, LLC (West Medway II), our indirect subsidiary, entered into a financing agreement for a $150 million nonrecourse senior secured term loan credit facility with a maturity date of March 31, 2026. The term loan bears interest at an average blended interest rate of LIBOR plus 3%, paid quarterly. In addition to the financing, West Medway II, entered into interest rate swaps with an initial notional amount of $113 million at an interest rate of 0.61%, paid quarterly, to manage a portion of the interest rate exposure in connection with the financing. We used the net proceeds for general corporate purposes. Our interests in West Medway II, were pledged as collateral for this financing. As of September 30, 2021, approximately $145 million was outstanding.

See Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on nonrecourse debt and Note 12 — Derivative Financial Instruments for additional information on interest rate swaps.

14. Fair Value of Financial Assets and Liabilities

We measure and classify fair value measurements in accordance with the hierarchy as defined by GAAP. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

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- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the short-term liabilities, long-term debt, and SNF obligation as of September 30, 2021 and December 31, 2020. We have no financial liabilities classified as Level 1.

The carrying amounts of the short-term liabilities as presented in the Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

	September 30, 2021				December 31, 2020			
	Carrying Amount	Fair Value			Carrying Amount	Fair Value		
		Level 2	Level 3	Total		Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year[(a)]	$6,130	$5,835	$1,111	$6,946	$6,087	$5,648	$1,208	$6,856
SNF Obligation	1,209	1,021	—	1,021	1,208	909	—	909

(a) Includes unamortized debt issuance costs which are not fair valued.

Recurring Fair Value Measurements

The following tables present assets and liabilities measured and recorded at fair value in the Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2021 and December 31, 2020:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

	As of September 30, 2021					As of December 31, 2020				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents[a]	$ 1,673	$ —	$ —	$ —	$ 1,673	$ 124	$ —	$ —	$ —	$ 124
NDT fund investments										
Cash equivalents[b]	647	135	—	—	782	210	95	—	—	305
Equities	4,373	1,717	1	1,559	7,650	3,886	2,077	—	1,562	7,525
Fixed income										
Corporate debt[c]	—	1,155	287	—	1,442	—	1,485	285	—	1,770
U.S. Treasury and agencies	2,192	29	—	—	2,221	1,871	126	—	—	1,997
Foreign governments	—	54	—	—	54	—	56	—	—	56
State and municipal debt	—	29	—	—	29	—	101	—	—	101
Other	31	29	—	1,259	1,319	—	41	—	961	1,002
Fixed income subtotal	2,223	1,296	287	1,259	5,065	1,871	1,809	285	961	4,926
Private credit	—	—	187	592	779	—	—	212	629	841
Private equity	—	—	—	654	654	—	—	—	504	504
Real estate	—	—	—	802	802	—	—	—	679	679
NDT fund investments subtotal[d][e]	7,243	3,148	475	4,866	15,732	5,967	3,981	497	4,335	14,780
Rabbi trust investments										
Cash equivalents	4	—	—	—	4	4	—	—	—	4
Mutual funds	35	—	—	—	35	29	—	—	—	29
Life insurance contracts	—	33	—	—	33	—	28	—	—	28
Rabbi trust investments subtotal	39	33	—	—	72	33	28	—	—	61
Investments in equities[f]	137	—	—	—	137	195	—	—	—	195
Commodity derivative assets										
Economic hedges	5,527	10,633	7,083	—	23,243	745	1,914	1,599	—	4,258
Proprietary trading	—	56	12	—	68	—	17	27	—	44
Effect of netting and allocation of collateral[g][h]	(4,468)	(9,869)	(6,808)	—	(21,145)	(607)	(1,597)	(905)	—	(3,109)
Commodity derivative assets subtotal	1,059	820	287	—	2,166	138	334	721	—	1,193
DPP consideration	—	501	—	—	501	—	639	—	—	639
Total assets	10,151	4,502	762	4,866	20,281	6,457	4,982	1,218	4,335	16,992
Liabilities										
Commodity derivative liabilities										
Economic hedges	(4,126)	(9,192)	(8,340)	—	(21,658)	(682)	(1,928)	(1,354)	—	(3,964)
Proprietary trading	—	(32)	(26)	—	(58)	—	(21)	(4)	—	(25)
Effect of netting and allocation of collateral[g][h]	4,123	9,159	6,218	—	19,500	540	1,918	1,067	—	3,525
Commodity derivative liabilities subtotal	(3)	(65)	(2,148)	—	(2,216)	(142)	(31)	(291)	—	(464)
Deferred compensation obligation	—	(44)	—	—	(44)	—	(42)	—	—	(42)
Total liabilities	(3)	(109)	(2,148)	—	(2,260)	(142)	(73)	(291)	—	(506)
Total net assets (liabilities)	$10,148	$ 4,393	$(1,386)	$4,866	$ 18,021	$6,315	$ 4,909	$ 927	$4,335	$16,486

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

(a) We exclude cash of $292 million and $171 million at September 30, 2021 and December 31, 2020, respectively, and restricted cash of $54 million and $20 million at September 30, 2021 and December 31, 2020, respectively.

(b) Includes $109 million and $116 million of cash received from outstanding repurchase agreements at September 30, 2021 and December 31, 2020, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (e) below.

(c) Includes investments in equities sold short of $(50) million and $(62) million as of September 30, 2021 and December 31, 2020, respectively, held in an investment vehicle primarily to hedge the equity option component of its convertible debt.

(d) Includes net derivative liabilities of less than $1 million and net derivative assets of $2 million, which have total notional amounts of $728 million and $1,043 million at September 30, 2021 and December 31, 2020, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of our exposure to credit or market loss.

(e) Excludes net liabilities of $130 million and $181 million at September 30, 2021 and December 31, 2020, respectively, which include certain derivative assets that have notional amounts of $194 million and $104 million at September 30, 2021 and December 31, 2020, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(f) Includes equity investments held by us which were previously designated as equity investments without readily determinable fair value but are now publicly traded and therefore have readily determinable fair values. The first investment became publicly traded in the fourth quarter of 2020. We record the fair value of these investments in Other current assets in the Consolidated Balance Sheets based on the quoted market prices of the stocks as of the respective balance sheet date. There were no equity investments without readily determinable fair value that became publicly traded during the third quarter of 2021. For investments that became publicly traded during the first half of 2021, unrealized gains of $220 million were recorded in Other, net in the Consolidated Statements of Operations and Comprehensive Income.

(g) Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $(345) million, $(710) million, and $(590) million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of September 30, 2021. Collateral (received)/posted from counterparties, net of collateral paid to counterparties, totaled $(67) million, $321 million, and $162 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2020.

(h) Includes $2,084 million held and $209 million posted of variation margin with the exchanges as of September 30, 2021 and December 31, 2020, respectively.

As of September 30, 2021, we have outstanding commitments to invest in private credit, private equity, and real estate investments of approximately $359 million, $174 million, and $371 million, respectively. These commitments will be funded by our existing NDT funds.

We held investments without readily determinable fair values with carrying amounts of $32 million and $55 million as of September 30, 2021 and December 31, 2020, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the nine months ended September 30, 2021 and for the year ended December 31, 2020.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the nine months ended September 30, 2021 and 2020:

	Nine months ended September 30, 2021		
	NDT Fund Investments	Mark-to-Market Derivatives	Total
Balance as of December 31, 2020	$497	$ 430	$ 927
Total realized / unrealized gains (losses)			
Included in net income	4	(1,606)[a]	(1,602)
Included in noncurrent payables to affiliates	18	—	18
Change in collateral	—	(751)	(751)
Purchases, sales, and settlements			
Purchases	3	120	123
Sales	—	7	7
Settlements	(48)	—	(48)
Transfers into Level 3	1	3[b]	4
Transfers out of Level 3	—	(64)[b]	(64)
Balance as of September 30, 2021	$475	$(1,861)	$(1,386)
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2021	$ 4	$(1,527)	$(1,523)

	Nine Months Ended September 30, 2020		
	NDT Fund Investments	Mark-to-Market Derivatives	Total
Balance as of December 31, 2019	$511	$ 817	$1,328
Total realized / unrealized gains (losses)			
Included in net income	1	(474)[a]	(473)
Included in noncurrent payables to affiliates	17	—	17
Change in collateral	—	(120)	(120)
Purchases, sales, and settlements			
Purchases	6	130	136
Sales	—	(27)	(27)
Settlements	(18)	—	(18)
Transfers into Level 3	1	(6)[b]	(5)
Transfers out of Level 3	—	13[b]	13
Balance as of September 30, 2020	$518	$ 333	$ 851
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2020	$ 1	$ (98)	$ (97)

(a) Includes a reduction of $80 million for realized gains due to the settlement of derivative contracts for

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the nine months ended September 30, 2021. Includes a reduction of $376 million for realized gains due to the settlement of derivative contracts for the nine months ended September 30, 2020.

(b) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis for the nine months ended September 30, 2021 and 2020:

	Operating Revenues	Purchased Power and Fuel	Other, net
Total (losses) gains included in net income for the nine months ended September 30, 2021	(1,944)	338	4
Total unrealized (losses) gains for the nine months ended September 30, 2021	(1,969)	443	4

	Operating Revenues	Purchased Power and Fuel	Other, net
Total losses included in net income for the nine months ended September 30, 2020	(370)	(104)	—
Total unrealized (losses) gains for the nine months ended September 30, 2020	(50)	(48)	1

Valuation Techniques Used to Determine Fair Value

Our valuation techniques used to measure the fair value of the assets and liabilities shown in the tables below are in accordance with the policies discussed in Note 18 — Fair Value of Financial Assets and Liabilities of the Notes to Audited Consolidated Financial Statements.

Valuation Techniques Used to Determine Net asset Value

Certain NDT Fund Investments are not classified within the fair value hierarchy and are included under the heading “Not subject to leveling” in the table above. These investments are measured at fair value using NAV per share as a practical expedient and include commingled funds, mutual funds which are not publicly quoted, managed private credit funds, private equity and real estate funds.

For commingled funds and mutual funds, which are not publicly quoted, the fair value is primarily derived from the quoted prices in active markets on the underlying securities and can typically be redeemed monthly with 30 or less days of notice and without further restrictions. For managed private credit funds, the fair value is determined using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on our understanding of the investment funds. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

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Mark-to-Market Derivatives

The table below discloses the significant inputs to the forward curve used to value mark-to-market derivatives.

Type of trade	Fair Value at September	Fair Value at December	Valuation Technique	Unobservable Input	2021 Range & Arithmetic Average			2020 Range & Arithmetic Average		
Mark-to- market derivatives – Economic Hedges[(a)(b)]	$(1,275)	$245	Discounted Cash Flow	Forward power price	$9.77	$ 301	$ 55	$2.25-	$ 163	$ 30
				Forward gas price	$1.76	$23.00	$4.16	$1.57-	$7.88	$2.59
			Option Model	Volatility percentage	35%	197%	49%	11%	237%	32%
Mark-to-market derivatives – Proprietary trading[(a)(b)]	$ (14)	$ 23	Discounted Cash Flow	Forward power price	$ 16	$ 156	$ 53	$ 10	$ 106	$ 27

(a) The valuation techniques, unobservable inputs, ranges and arithmetic averages are the same for the asset and liability positions.

(b) The fair values do not include cash collateral (received)/posted on level three positions of $(590) million and $162 million as of September 30, 2021 and December 31, 2020, respectively.

The inputs listed above, which are as of the balance sheet date, would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of our commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give us the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give us the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

15. Commitments and Contingencies

The following is an update to the current status of commitments and contingencies set forth in Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements.

Commercial Commitments. Commercial commitments as of September 30, 2021, representing commitments potentially triggered by future events were as follows:

		Expiration within					
	Total	2021	2022	2023	2024	2025	2026 and beyond
Letters of credit	$2,223	$264	$1,846	$113	$ —	$ —	$ —
Surety bonds[(a)]	826	352	474	—	—	—	—
Total commercial commitments	$3,049	$616	$2,320	$113	$ —	$ —	$ —

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(a) Surety bonds — Guarantees issued related to contract and commercial agreements, excluding bid bonds.

Environmental Remediation Matters

General. Our operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, we are generally liable for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances generated by us. We own or lease a number of real estate parcels, including parcels on which our operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, we are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, we cannot reasonably estimate whether we will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by us, environmental agencies or others. Additional costs could have a material, unfavorable impact on the financial statements.

As of September 30, 2021 and December 31, 2020, we had accrued undiscounted amounts of $119 million and $121 million, respectively, for environmental liabilities recorded in Other current liabilities and Other deferred credits and other liabilities in the Consolidated Balance Sheets.

Cotter Corporation. The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon’s 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to us. Including Cotter, there are three PRPs participating in the West Lake Landfill remediation proceeding. Our investigation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing.

In September 2018, the EPA issued its Record of Decision Amendment (RODA) for the selection of a final remedy. The RODA modified the remedy previously selected by EPA in its 2008 Record of Decision (ROD). While the ROD required only that the radiological materials and other wastes at the site be capped, the 2018 RODA requires partial excavation of the radiological materials in addition to the previously selected capping remedy. The RODA also allows for variation in depths of excavation depending on radiological concentrations. The EPA and the PRPs have entered into a Consent Agreement to perform the Remedial Design, which is expected to be completed in late 2024. In March 2019 the PRPs received Special Notice Letters from the EPA to perform the Remedial Action work. On October 8, 2019, Cotter (our indemnitee) provided a non-binding good faith offer to conduct, or finance, a portion of the remedy, subject to certain conditions. The total estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred collectively by the PRPs in fully executing the remedy, is approximately $290 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. We have determined that a loss associated with the EPA’s partial excavation and enhanced landfill cover remedy is probable and have recorded a liability, included in the total amount discussed above, that reflects management’s best estimate of Cotter’s allocable share of the ultimate cost. Given the joint and several nature of this liability, the magnitude of our ultimate liability will depend on the actual costs incurred to implement the required remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Cotter’s associated allocable share could differ significantly once these uncertainties are resolved, which could have a material impact in the future financial statements.

One of the other PRPs has indicated it will be making a contribution claim against Cotter for costs that it has incurred to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, we do not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact in the financial statements.

In January 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. In September 2018, the PRPs agreed to an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater Remedial Investigation and Feasibility Study (RI/FS). The purpose of this RI/FS is to define the nature and extent of any groundwater contamination from the West Lake Landfill site and evaluate remedial alternatives. We estimate the undiscounted cost for the groundwater RI/FS to be approximately $40 million. We determined a loss associated with the RI/FS is probable and have recorded a liability, included in the total amount as discussed above, that reflects management’s best estimate of Cotter’s allocable share of the cost among the PRPs. At this time we cannot predict the likelihood or the extent to which, if any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact in the future financial statements.

In August 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government’s clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd’s (now our) indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government’s Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until February 28, 2022 so that settlement discussions can proceed. On August 3, 2020, the DOJ advised Cotter and the other PRPs that it is seeking approximately $90 million from all the PRPs and has directed that the PRPs must submit a good faith joint proposed settlement offer. At this time, the DOJ has stayed their request for a good faith offer while the parties review cost documentation associated with the cost claim. We have determined that a loss associated with this matter is probable under our indemnification agreement with Cotter and have recorded an estimated liability, included in the total amount discussed above.

Benning Road Site. In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility, which was deactivated in June 2012. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River.

Since 2013, Pepco and Pepco Energy Services (now us, pursuant to Exelon’s 2016 acquisition of PHI) have been performing RI work and have submitted multiple draft RI reports to the DOEE. In September 2019, we and Pepco issued a draft “final” RI report which the DOEE approved on February 3, 2020. We and Pepco are developing a FS to evaluate possible remedial alternatives for submission to the DOEE. The Court has established a schedule for completion of the FS, and approval by the DOEE, by March 16, 2022. After completion and approval of the FS, the DOEE will prepare a Proposed Plan for public comment and then issue a ROD identifying any further response actions determined to be necessary. We have determined that a loss associated with this matter is probable and have accrued an estimated liability, included in the total amount discussed above.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims. We maintain a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by us or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At September 30, 2021 and December 31, 2020, we recorded estimated liabilities of approximately $82 million and $89 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2021, approximately $19 million of this amount related to 211 open claims presented to us, while the remaining $63 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2055, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, we monitor actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether adjustments to the estimated liabilities are necessary.

It is reasonably possible that additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued could have a material, unfavorable impact in the financial statements. However, management cannot reasonably estimate a range of loss beyond the amounts recorded.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages. Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. See Note 3 — Regulatory Matters for additional information.

Various lawsuits have been filed against us since March 2021 related to these events, including

- On March 5, 2021, we, along with more than 160 power generators and transmission and distribution companies, were sued by approximately 160 individually named plaintiffs, purportedly on behalf of all Texans who allegedly suffered loss of life or sustained personal injury, property damage or other losses as a result of the weather events. The plaintiffs allege that the defendants failed to properly prepare for the cold weather and failed to properly conduct their operations, seeking compensatory as well as punitive damages. On April 26, 2021, another multi-plaintiff lawsuit was filed on behalf of approximately 90 plaintiffs against more than 300 defendants, including us, involving similar allegations of liability and claims of personal injury and property damage. Since March 2021, approximately 60 additional lawsuits, naming multiple defendants including us, were filed by individual or multiple plaintiffs in different Texas counties, all arising out of the February weather events. These additional lawsuits allege wrongful death, property damage, or other losses. Co-defendants in these lawsuits include ERCOT, transmission and distribution utilities and other generators. We dispute liability and deny that we are responsible for any of plaintiffs' alleged claims and are vigorously contesting them. No loss contingencies have been reflected in the consolidated financial statements with respect to these matters, as such contingencies are neither probable nor reasonably estimable at this time.
- On March 22, 2021, an LDC filed a lawsuit in Missouri federal court against us for breach of contract and unjust enrichment, seeking damages of approximately $40 million. The plaintiff claims that we failed to deliver gas to its customers in February of 2021, causing the plaintiff to incur damages by forcing it to purchase gas for our customers and by our refusal to pay the resulting penalties. On March 26, 2021, we filed a complaint with the MPSC against the LDC to void the OFO penalties, or alternatively to grant a waiver or variance from the tariff requirements, to prohibit the LDC from billing or otherwise attempting to collect from us or any Missouri customer any portion of the penalties claimed by the LDC until the resolution of the complaint, and to prohibit the LDC from taking any retaliatory measure, including termination of service. On September 1, 2021, the MPSC consolidated our complaint with two other similar complaints from other companies. The

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evidentiary hearing for the three consolidated complaint cases is scheduled for March 2022. Based on the penalty provisions within the tariff that was in effect at the relevant time, we have recorded a liability of approximately $40 million as of September 30, 2021.

General. We are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. We maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

16. Variable Interest Entities

At September 30, 2021 and December 31, 2020, we consolidated several VIEs or VIE groups for which we are the primary beneficiary (see *Consolidated VIEs* below) and had significant interests in several other VIEs for which we do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary (see *Unconsolidated VIEs* below). Consolidated and unconsolidated VIEs are aggregated to the extent that the entities have similar risk profiles.

Consolidated VIEs

The table below shows the carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the consolidated financial statements as of September 30, 2021 and December 31, 2020. The assets, except as noted in the footnotes to the table below, can only be used to settle obligations of the VIEs. The liabilities, except as noted in the footnote to the table below, are such that creditors, or beneficiaries, do not have recourse to our general credit.

	September 30, 2021	December 31, 2020
Cash and cash equivalents	$ 38	$ 98
Restricted cash and cash equivalents	42	44
Accounts receivable		
Customer	25	148
Other	7	36
Unamortized energy contract assets	21	22
Inventories, net		
Materials and supplies	14	244
Assets held for sale[a]	—	101
Other current assets	513	669
Total current assets	660	1,362
Property, plant, and equipment, net	2,052	5,803
Nuclear decommissioning trust funds	—	3,007
Unamortized energy contract assets	210	249
Other noncurrent assets	13	42
Total noncurrent assets	2,275	9,101
Total assets[b]	$2,935	$10,463
Long-term debt due within one year	$ 70	$ 68

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	September 30, 2021	December 31, 2020
Accounts payable	11	81
Accrued expenses	14	70
Unamortized energy contract liabilities	—	4
Liabilities held for sale[(a)]	—	16
Other current liabilities	—	5
Total current liabilities	95	244
Long-term debt	832	889
Asset retirement obligations	149	2,318
Other noncurrent liabilities	3	129
Total noncurrent liabilities	984	3,336
Total liabilities[(c)]	$1,079	$ 3,580

(a) In the fourth quarter of 2020, we entered into an agreement for the sale of a significant portion of our solar business, and as a result of this transaction, we reclassified the consolidated VIEs' solar assets and liabilities as held for sale. Completion of the transaction occurred in the first quarter of 2021. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the solar business.

(b) Our balances include unrestricted assets for current unamortized energy contract assets of $21 million and $22 million, non-current unamortized energy contract assets of $210 million and $249 million, assets held for sale of $0 million and $9 million, and other unrestricted assets of $0 million and $1 million as of September 30, 2021 and December 31, 2020, respectively

(c) Our balances include liabilities with recourse of $1 million and $8 million as of September 30, 2021 and December 31, 2020, respectively.

As of September 30, 2021 and December 31, 2020, our consolidated VIEs included the following:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason we are primary beneficiary:
CENG – A joint venture between us and EDF. We had a 50.01% equity ownership in CENG as of December 31, 2020 and acquired EDF's 49.99% equity interest on August 6,2021 resulting in CENG no longer being classified as a consolidated VIE beginning in the third quarter of 2021. See additional discussion below.	Disproportionate relationship between equity interest and operational control as a result of the NOSA described further below.	We conduct the operational activities.
EGRP – A collection of wind and solar project entities. We have a 51% equity ownership in EGRP. See additional discussion below.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
Bluestem Wind Energy Holdings, LLC – A Tax Equity structure which is consolidated by EGRP. We have a noncontrolling	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general	We conduct the operational activities.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason we are primary beneficiary:
interest.	partner.	
Antelope Valley – A solar generating facility, which is 100% owned by us. Antelope Valley sells all of its output to PG&E through a PPA.	The PPA contract absorbs variability through a performance guarantee.	We conduct all activities.
Equity investment in distributed energy company – We have a 31% equity ownership. This distributed energy company has an interest in an unconsolidated VIE. (See Unconsolidated VIEs disclosure below). We fully impaired this investment in 2019.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
NER – A bankruptcy remote, special purpose entity which is 100% owned by us, which purchases certain of our customer accounts receivable arising from the sale of retail electricity. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. See Note 6 – Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	We conduct all activities.

CENG — On April 1, 2014, we, CENG, and subsidiaries of CENG executed the NOSA pursuant to which we conduct all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of our nuclear fleet, subject to the CENG member rights of EDF.

On November 20, 2019, we received notice of EDF's intention to exercise the put option to sell us its 49.99% equity interest in CENG and the put automatically exercised on January 19, 2020. On August 6, 2021, we entered into a settlement agreement with EDF pursuant to which we purchased EDF's equity interest in CENG and resulted in CENG no longer being classified as a consolidated VIE beginning in the third quarter of 2021. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

We provide the following support to CENG:

- We executed an Indemnity Agreement pursuant to which we agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees our obligations under this Indemnity Agreement. See Note 19 — Commitments and Contingencies of the Notes to Audited Consolidated Financial Statements for more details.
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

Prior to August 6, 2021, we and EDF shared in the $688 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance. Following the execution of the settlement agreement, EDF no longer shares in the obligation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

EGRP **—** EGRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by EGRP. We own a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by EGRP. While we or EGRP own 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and wind entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. We are the primary beneficiary of these solar and wind entities that qualify as VIEs because we control the design, construction, and operation of the facilities. There is limited recourse to us related to certain solar and wind entities.

In 2017, our interests in EGRP were contributed to and are pledged for the ExGen Renewables IV non-recourse debt project financing structure. Refer to Note 17 — Debt and Credit Agreements of the Notes to Audited Consolidated Financial Statements for additional information on ExGen Renewables IV.

Unconsolidated VIEs

Our variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected in Investments in the Consolidated Balance Sheets. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in the Consolidated Balance Sheets that relate to our involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, us for the deliveries associated with the current billing cycles under the commercial agreements.

As of September 30, 2021 and December 31, 2020, we had significant unconsolidated variable interests in several VIEs for which we were not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements.

The following table presents summary information about our significant unconsolidated VIE entities:

	September 30, 2021			December 31, 2020		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$781	$370	$1,151	$777	$401	$1,178
Total liabilities[(a)]	80	209	289	61	223	284
Exelon's ownership interest in VIE[(a)]	—	143	143	—	157	157
Other ownership interests in VIE[(a)]	701	18	719	716	21	737

(a) These items represent amounts in the unconsolidated VIE balance sheets, not in the Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. We do not have any exposure to loss as we do not have a carrying amount in the equity investment VIEs as of September 30, 2021 and December 31, 2020.

As of September 30, 2021 and December 31, 2020, the unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
Equity investments in distributed energy companies – 1) We have a 90% equity ownership in a distributed energy company.	Similar structures to a limited partnership and the limited partners do not have kick out rights with respect to the general	We do not conduct the operational activities.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
2) We, via a consolidated VIE, have a 90% equity ownership in another distributed energy company (See Consolidated VIEs disclosure above). We fully impaired this investment in 2019.	partner.	
Energy Purchase and Sale agreements – We have several energy purchase and sale agreements with generating facilities.	PPA contracts that absorb variability through fixed pricing.	We do not conduct the operational activities.

17. Supplemental Financial Information

Supplemental Statement of Operations Information

The following tables provide additional information about material items recorded in the Consolidated Statements of Operations and Comprehensive Income.

	Operating revenues	
	Nine Months Ended September 30,	
	2021	2020
Operating lease income	$ 44	$ 43
Variable lease income	207	224

	Taxes other than income taxes	
	Nine Months Ended September 30,	
	2021	2020
Gross receipts[(a)]	$ 73	$ 75
Property	199	199
Payroll	83	88

(a) Represent gross receipts taxes related to our retail operations. The offsetting collection of gross receipts taxes from customers is recorded in revenues in the Consolidated Statements of Operations and Comprehensive Income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

	Other, Net	
	Nine Months Ended September 30,	
	2021	2020
Decommissioning-related activities:		
Net realized income on NDT funds[(a)]		
Regulatory Agreement Units	$ 698	$ 127
Non-Regulatory Agreement Units	392	127
Net unrealized gains on NDT funds		
Regulatory Agreement Units	84	111
Non-Regulatory Agreement Units	38	1
Regulatory offset to NDT fund-related activities[(b)]	(607)	(192)
Decommissioning-related activities	605	174
Net unrealized losses from equity investments[(c)]	(83)	—

(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.

(b) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of income taxes related to all NDT fund activity for those units. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations of the Notes to Audited Consolidated Financial Statements for additional information regarding the accounting for nuclear decommissioning and Note 8 — Nuclear Decommissioning for additional information on the contractual offset suspension for the Byron units.

(c) Net unrealized losses from equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021.

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Consolidated Statements of Cash Flows.

	Depreciation, amortization and accretion	
	Nine Months Ended September 30,	
	2021	2020
Property, plant, and equipment[(a)]	$2,698	$1,121
Amortization of intangible assets, net[(a)]	37	40
Amortization of energy contract assets and liabilities[(b)]	23	22
Nuclear fuel[(c)]	810	708
ARO accretion[(d)]	383	375
Total depreciation, amortization and accretion	$3,951	$2,266

(a) Included in Depreciation and amortization in the Consolidated Statements of Operations and Comprehensive Income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

(b) Included in Operating revenues or Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.

(c) Included in Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.

(d) Included in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

	Other non-cash operating activities	
	Nine Months Ended September 30,	
	2021	2020
Pension and non-pension postretirement benefit costs	$ 92	$ 89
Allowance for credit losses	59	16
Other decommissioning-related activity[(a)]	(810)	(301)
Energy-related options[(b)]	45	79
Severance Costs	(75)	88
Provision for excess and obsolete inventory	—	118
Amortization of operating ROU asset	98	135

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations of the Notes to Audited Consolidated Financial Statements for additional information regarding the accounting for nuclear decommissioning and Note 8 — Nuclear Decommissioning for additional information on the contractual offset suspension for the Byron units.

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

The following tables provide a reconciliation of cash, cash equivalents and restricted cash reported in the Consolidated Balance Sheets that sum to the total of the same amounts in the Consolidated Statements of Cash Flows.

	September 30, 2021	December 31, 2020	September 30, 2020	December 31, 2019
Cash and cash equivalents	$1,957	$226	$623	$303
Restricted cash and cash equivalents	62	89	100	146
Cash, restricted cash, and cash equivalents – Held for Sale	—	12	—	—
Total cash, restricted cash, and cash equivalents	$2,019	$327	$723	$449

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the Notes to Audited Consolidated Financial Statements.

Supplemental Balance Sheet Information

The following tables provide additional information about material items recorded in the Consolidated Balance Sheets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

	Accrued expenses	
	September 30, 2021	December 31, 2020
Compensation-related accruals[a]	$318	$426
Taxes accrued	222	229
Interest accrued	77	44

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.

18. Related Party Transactions

Operating revenues from affiliates

The following table presents our Operating revenues from affiliates:

	Nine Months Ended September 30,	
	2021	2020
ComEd[a]	$249	$241
PECO[b]	142	146
BGE[c]	195	252
PHI	276	288
Pepco[d]	199	219
DPL[e]	63	60
ACE[f]	14	9
Other	10	5
Total operating revenues from affiliates	$872	$932

(a) We have an ICC-approved RFP contract with ComEd to provide a portion of ComEd’s electricity supply requirements. We also sell RECs and ZECs to ComEd.

(b) We provide electric supply to PECO under contracts executed through PECO’s competitive procurement process. In addition, we have a ten-year agreement with PECO to sell solar AECs.

(c) We provide a portion of BGE’s energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.

(d) We provide electric supply to Pepco under contracts executed through Pepco’s competitive procurement process approved by the MDPSC and DCPSC.

(e) We provide a portion of DPL’s energy requirements under its MDPSC and DPSC-approved market-based SOS commodity programs.

(f) We provide electric supply to ACE under contracts executed through ACE’s competitive procurement process.

Service Company Costs for Corporate Support

We receive a variety of corporate support services from BSC. See Note 1 — Significant Accounting Policies for additional information regarding BSC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

The following table presents the service company costs allocated to us:

Operating and maintenance from affiliates		Capitalized costs	
Nine Months Ended September 30,		Nine Months Ended September 30,	
2021	2020	2021	2020
$424	$406	76	37

Current Receivables from/Payables to affiliates

The following tables present current receivables from affiliates and current payables to affiliates:

	September 30, 2021		December 31, 2020	
	Receivables from affiliates:	Payables to affiliates:	Receivables from affiliates:	Payables to affiliates:
ComEd	$103	$ 36	$ 78	$ 13
PECO	24	9	17	—
BGE	15	—	11	—
Pepco	22	—	13	—
DPL	4	—	3	—
ACE	7	—	6	—
BSC	—	86	—	72
Other	9	23	25	22
Total	$184	$154	$153	$107

Borrowings from Exelon intercompany money pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. We participate in the Exelon money pool.

Noncurrent Payables to affiliates

We have long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 10 — Asset Retirement Obligations of the Notes to Audited Consolidated Financial Statements for additional information.

The following table presents noncurrent payables to affiliates in the Consolidated Balance Sheets:

	September 30, 2021	December 31, 2020
ComEd	$2,597	$2,541
PECO	546	475

Long-term debt to affiliates

In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and our subsidiaries (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term debt to affiliates in the Consolidated Balance Sheets.

Consolidated financial statements of Exelon Generation Company, LLC for the years ended December 31, 2020, 2019 and 2018

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(2)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(2)(ii), of Exelon Generation Company, LLC and its subsidiaries (the “Company”) (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Annual Nuclear Decommissioning Asset Retirement Obligations (ARO) Assessment

As described in Notes 1 and 10 to the consolidated financial statements, the Company has a legal obligation to decommission its nuclear generation stations following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, management uses a probability-weighted cash flow model, which on a unit-by-unit basis, considers multiple scenarios that include significant estimates and assumptions such as decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Management updates its ARO annually unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. As of December 31, 2020, the nuclear decommissioning ARO was approximately $11.9 billion.

The principal considerations for our determination that performing procedures relating to the Company’s annual ARO assessment is a critical audit matter are the significant judgment by management when estimating its decommissioning obligation; this in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the reasonableness of management’s cash flow model and significant assumptions related to decommissioning cost studies. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s development of the inputs, assumptions, and model used in management’s ARO assessment. These procedures also included, among others, testing management’s process for developing the ARO estimates by evaluating the appropriateness of the cash flow model, testing the completeness and accuracy of data used by management, and evaluating the reasonableness of management’s significant assumptions related to decommissioning cost studies. Professionals with specialized skill and knowledge were used to assist in evaluating the results of decommissioning cost studies.

Impairment Assessment of Long-Lived Generation Assets

As described in Notes 1 and 12 to the consolidated financial statements, the Company evaluates the carrying value of long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, or plans to dispose of a long-lived asset significantly before the end of its useful life. Management determines if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The expected future cash flows include significant unobservable inputs including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As of December 31, 2020, the total carrying value of long-lived generation assets subject to this evaluation was approximately $22.2 billion.

The principal considerations for our determination that performing procedures relating to the Company’s impairment assessment of long-lived generation assets is a critical audit matter are the significant judgment by management in assessing the recoverability of these asset groups; this in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating the reasonableness of management’s significant assumptions related to revenue and generation forecasts. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s development of the inputs, assumptions, and model used to estimate the recoverability and fair value of the Company’s long-lived generation asset groups. These procedures also included, among others, testing management’s process for developing expected future cash flows for long-lived generation asset groups by evaluating the appropriateness of the future cash flow model, testing the completeness and accuracy of the data used by management, and evaluating the reasonableness of management’s significant assumptions related to revenue and generation forecasts. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of revenue forecasts.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland

February 24, 2021

We have served as the Company’s auditor since 2001.

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating revenues			
Operating revenues	$16,392	$17,752	$19,169
Operating revenues from affiliates	1,211	1,172	1,268
Total operating revenues	17,603	18,924	20,437
Operating expenses			
Purchased power and fuel	9,592	10,849	11,679
Purchased power and fuel from affiliates	(7)	7	14
Operating and maintenance	4,613	4,131	4,803
Operating and maintenance from affiliates	555	587	661
Depreciation and amortization	2,123	1,535	1,797
Taxes other than income taxes	482	519	556
Total operating expenses	17,358	17,628	19,510
Gain on sales of assets and businesses	11	27	48
Operating income	256	1,323	975
Other income and (deductions)			
Interest expense, net	(328)	(394)	(396)
Interest expense to affiliates	(29)	(35)	(36)
Other, net	937	1,023	(178)
Total other income and (deductions)	580	594	(610)
Income before income taxes	836	1,917	365
Income taxes	249	516	(108)
Equity in losses of unconsolidated affiliates	(8)	(184)	(30)
Net income	579	1,217	443
Net (loss) income attributable to noncontrolling interests	(10)	92	73
Net income attributable to membership interest	$ 589	$ 1,125	$ 370
Comprehensive income, net of income taxes			
Net income	$ 579	$ 1,217	$ 443
Other comprehensive income (loss), net of income taxes			
Unrealized (loss) gain on cash flow hedges	(2)	—	12
Unrealized gain on investments in unconsolidated affiliates	—	1	1
Unrealized gain (loss) on foreign currency translation	4	6	(10)
Other comprehensive income	2	7	3
Comprehensive income	$ 581	$ 1,224	$ 446
Comprehensive (loss) income attributable to noncontrolling interests	(10)	93	74
Comprehensive income attributable to membership interest	$ 591	$ 1,131	$ 372

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2020	2019	2018
Cash flows from operating activities			
Net income	$ 579	$ 1,217	$ 443
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	3,636	3,063	3,415
Asset impairments	563	201	50
Gain on sales of assets and businesses	(11)	(27)	(48)
Deferred income taxes and amortization of investment tax credits	78	361	(451)
Net fair value changes related to derivatives	(270)	228	307
Net realized and unrealized (gains) losses on NDT fund investments	(461)	(663)	303
Unrealized gain on equity investments	(186)	—	—
Other non-cash operating activities	18	(124)	298
Changes in assets and liabilities:			
Accounts receivable	1,125	(186)	(359)
Receivables from and payables to affiliates, net	24	(52)	8
Inventories	(77)	(47)	(12)
Accounts payable and accrued expenses	(343)	(248)	376
Option premiums paid, net	(139)	(29)	(43)
Collateral received (posted), net	479	(481)	64
Income taxes	186	302	(193)
Pension and non-pension postretirement benefit contributions	(255)	(175)	(139)
Other assets and liabilities	(4,362)	(467)	(158)
Net cash flows provided by operating activities	584	2,873	3,861
Cash flows from investing activities			
Capital expenditures	(1,747)	(1,845)	(2,242)
Proceeds from NDT fund sales	3,341	10,051	8,762
Investment in NDT funds	(3,464)	(10,087)	(8,997)
Collection of DPP	3,771	—	—
Proceeds from sales of assets and businesses	46	52	90
Acquisitions of assets and businesses, net	—	(41)	(154)
Other investing activities	11	3	10
Net cash flows provided by (used in) investing activities	1,958	(1,867)	(2,531)
Cash flows from financing activities			
Change in short-term borrowings	20	320	—
Proceeds from short-term borrowings with maturities greater than 90 days	500	—	—
Issuance of long-term debt	3,155	42	15
Retirement of long-term debt	(4,334)	(813)	(141)
Retirement of long-term debt to affiliate	(550)	—	—
Changes in Exelon intercompany money pool	285	(100)	46
Distributions to member	(1,734)	(899)	(1,001)
Contributions from member	64	41	155
Other financing activities	(70)	(51)	(55)
Net cash flows used in financing activities	(2,664)	(1,460)	(981)
(Decrease) increase in cash, restricted cash, and cash equivalents	(122)	(454)	349
Cash, restricted cash, and cash equivalents at beginning of period	449	903	554
Cash, restricted cash, and cash equivalents at end of period	$ 327	$ 449	$ 903
Supplemental cash flow information			
Decrease in capital expenditures not paid	$ (88)	$ (34)	$ (199)
Increase in DPP	4,441	—	—
Increase (decrease) in PP&E related to ARO update	850	959	(130)

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 226	$ 303
Restricted cash and cash equivalents	89	146
Accounts receivable		
Customer accounts receivable	1,330	2,973
Customer allowance for credit losses	(32)	(80)
Customer accounts receivable, net	1,298	2,893
Other accounts receivable	352	619
Other accounts receivable, net	352	619
Mark-to-market derivative assets	644	675
Receivables from affiliates	153	190
Unamortized energy contract assets	38	47
Inventories, net		
Fossil fuel and emission allowances	233	236
Materials and supplies	978	1,026
Renewable energy credits	621	336
Assets held for sale	958	—
Other	1,357	605
Total current assets	6,947	7,076
Property, plant, and equipment (net of accumulated depreciation and amortization of $13,370 and $12,017 as of December 31, 2020 and 2019, respectively)	22,214	24,193
Deferred debits and other assets		
Nuclear decommissioning trust funds	14,464	13,190
Investments	184	235
Goodwill	47	47
Mark-to-market derivative assets	555	508
Prepaid pension asset	1,558	1,438
Unamortized energy contract assets	293	336
Deferred income taxes	6	12
Other	1,826	1,960
Total deferred debits and other assets	18,933	17,726
Total assets[(a)]	$48,094	$48,995

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	December 31, 2020	December 31, 2019
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 840	$ 320
Long-term debt due within one year	197	2,624
Long-term debt to affiliates due within one year	—	558
Accounts payable	1,253	1,692
Accrued expenses	788	786
Payables to affiliates	107	117
Borrowings from Exelon intercompany money pool	285	—
Mark-to-market derivative liabilities	262	215
Unamortized energy contract liabilities	7	17
Renewable energy credit obligation	661	443
Liabilities held for sale	375	—
Other	444	517
Total current liabilities	5,219	7,289
Long-term debt	5,566	4,464
Long-term debt to affiliates	324	328
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,656	3,752
Asset retirement obligations	12,054	10,603
Non-pension postretirement benefit obligations	858	878
Spent nuclear fuel obligation	1,208	1,199
Payables to affiliates	3,017	3,103
Mark-to-market derivative liabilities	205	123
Unamortized energy contract liabilities	3	11
Other	1,308	1,415
Total deferred credits and other liabilities	22,309	21,084
Total liabilities[(a)]	33,418	33,165
Commitments and contingencies		
Equity		
Member’s equity		
Membership interest	9,624	9,566
Undistributed earnings	2,805	3,950
Accumulated other comprehensive loss, net	(30)	(32)
Total member’s equity	12,399	13,484
Noncontrolling interests	2,277	2,346
Total equity	14,676	15,830
Total liabilities and equity	$48,094	$48,995

(a) Our consolidated assets include $10,182 million and $9,512 million at December 31, 2020 and 2019, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $3,572 million and $3,429 million at December 31, 2020 and 2019, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 21–Variable Interest Entities for additional information.

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2017	$9,357	$ 4,349	$(37)	$2,290	$15,959
Net income	—	370	—	73	443
Sale of noncontrolling interests	6	—	—	—	6
Changes in equity of noncontrolling interests	—	—	—	(60)	(60)
Distributions to member	—	(1,001)	—	—	(1,001)
Contributions from member	155	—	—	—	155
Other comprehensive income, net of income taxes	—	—	2	1	3
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	6	(3)	—	3
Balance, December 31, 2018	$9,518	$ 3,724	$(38)	$2,304	$15,508
Net income	—	1,125	—	92	1,217
Sale of noncontrolling interests	7	—	—	—	7
Changes in equity of noncontrolling interests	—	—	—	(48)	(48)
Distributions to member	—	(899)	—	—	(899)
Contributions from member	41	—	—	—	41
Other comprehensive income (loss), net of income taxes	—	—	6	(2)	4
Balance, December 31, 2019	$9,566	$ 3,950	$(32)	$2,346	$15,830
Net income	—	589	—	(10)	579
Sale of noncontrolling interests	3	—	—	—	3
Changes in equity of noncontrolling interests	—	—	—	(59)	(59)
Distribution to member of deferred taxes associated with net retirement benefit obligation	(9)	—	—	—	(9)
Distributions to member	—	(1,734)	—	—	(1,734)
Contributions from member	64	—	—	—	64
Other comprehensive income, net of income taxes	—	—	2	—	2
Balance, December 31, 2020	$9,624	$ 2,805	$(30)	$2,277	$14,676

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

1. Significant Accounting Policies

Description of Business

We are a company engaged in the generation, delivery and marketing of power across multiple geographical regions through our customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. We also sell natural gas, renewable energy and other energy-related products and services. We have five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions.

Basis of Presentation

On February 21, 2021, Exelon's Board of Directors approved a plan to separate Exelon's utility subsidiaries and Generation, creating two publicly traded companies. Under the separation plan, Exelon shareholders will retain their current shares of Exelon stock and receive a pro-rata distribution of shares of Constellation Energy Corporation stock in a transaction that is expected to be tax-free to Exelon and its shareholders for U.S. federal income tax purposes. The actual number of shares to be distributed to Exelon shareholders will be determined prior to closing. Exelon is targeting to complete the separation in the first quarter of 2022, subject to final approval by its Board of Directors, this Form 10 registration statement being declared effective by the SEC, regulatory approvals, and satisfaction of other conditions. The transaction is subject to approval by the FERC, NRC and NYPSC and receipt of a private letter ruling from the IRS and tax opinion from Exelon's tax advisors. There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing.

These Consolidated Financial Statements represent Generation's historical Consolidated Financial Statements presented in Exelon's combined Form 10-K for the year ended December 31, 2020 filed with the SEC on February 24, 2021. The Consolidated Financial Statements have been prepared in accordance with GAAP. The Consolidated Financial Statements include the accounts of our subsidiaries. All intercompany transactions have been eliminated. Unless otherwise indicated or the context otherwise requires, references herein to the terms "we," "us," and "our" refer to Generation as historically part of consolidated Exelon.

Through its business services subsidiary, BSC, Exelon provides us with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC are directly charged or allocated to us.

We own 100% of our significant consolidated subsidiaries, either directly or indirectly, except for certain consolidated VIEs, including CENG and EGRP, of which we hold a 50.01% and 51% interest, respectively. The remaining interests in these consolidated VIEs are included in noncontrolling interests on the Consolidated Balance Sheets. See Note 21 — Variable Interest Entities for additional information of consolidated VIEs.

We consolidate the accounts of entities in which we have a controlling financial interest, after the elimination of intercompany transactions. Where we do not have a controlling financial interest in an entity, proportionate consolidation, equity method accounting or accounting for investments in equity securities with or without readily determinable fair value is applied. We apply proportionate consolidation when we have an undivided interest in an asset and are proportionately liable for our share of each liability associated with the asset. We proportionately consolidate our undivided ownership interest in jointly owned electric plants. Under proportionate consolidation, we separately record our proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. We apply equity method accounting when we have a significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. We apply equity method accounting to certain investments and joint ventures. Under equity method accounting, we report our interest in the entity as an investment and our percentage share of the earnings from the entity as single line items in our financial

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

statements. We use accounting for investments in equity securities with or without readily determinable fair values if we lack a significant influence, which generally results when we hold less than 20% of the common stock of an entity. Under accounting for investments in equity securities with readily determinable fair values, the investments are reported based on quoted prices in active markets and realized and unrealized gains and losses are included in earnings. Under accounting for investments in equity securities without readily determinable fair values, the investments are reported at cost adjusted for changes from observable transactions for identical or similar investments of the same issuer, less impairment, and changes in measurement are reported in earnings.

COVID-19

We have taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19). We provide a critical service to our customers and have taken measures to keep employees who operate the business safe and minimize unnecessary risk of exposure to the virus, including extra precautions for employees who work in the field. We have implemented work from home policies where appropriate and imposed travel limitations on employees. In addition, we have updated our existing business continuity plan.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and accompanying notes, and the amounts of revenues and expenses reported during the periods covered by those financial statements and accompanying notes. Management assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to the allowance for credit losses and the carrying value of other long-lived assets, in context with the information reasonably available to us and the unknown future impacts of COVID-19 as of December 31, 2020 and through the date of this report. Our future assessment of our current expectation of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to our consolidated financial statements in future reporting periods.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and OPEB, inventory reserves, allowance for credit losses, asset impairment assessments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Revenues

Operating Revenues. Our operating revenues generally consist of revenues from contracts with customers involving the sale and delivery of energy commodities and related products and services and realized and unrealized revenues recognized under mark-to-market energy commodity derivative contracts. We recognize revenue from contracts with customers to depict the transfer of goods or services to customers in an amount that we expect to be entitled to in exchange for those goods or services. Our primary source of revenue includes competitive sales of power, natural gas, and other energy-related products and services. At the end of each reporting period, we accrue an estimate for the unbilled amount of energy delivered or services provided to customers.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. See Note 16 — Derivative Financial Instruments for additional information.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Taxes Directly Imposed on Revenue-Producing Transactions. We collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees, that are levied by state or local governments on the sale or distribution of electricity and natural gas. Some of these taxes are imposed on the customer, but paid by us, while others are imposed on us. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on us, such as gross receipts taxes, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 22 — Supplemental Financial Information for the taxes that are presented on a gross basis.

Leases

We adopted new accounting guidance issued by the FASB related to leases as of January 1, 2019. We recognize a ROU asset and lease liability for operating leases with a term of greater than one year. Operating lease ROU assets are included in Other deferred debits and other assets and operating lease liabilities are included in Other current liabilities and Other deferred credits and other liabilities on the Consolidated Balance Sheets. The ROU asset is measured as the sum of (1) the present value of all remaining fixed and in-substance fixed payments using our incremental borrowing rate, (2) any lease payments made at or before the commencement date (less any lease incentives received) and (3) any initial direct costs incurred. The lease liability is measured the same as the ROU asset, but excludes any payments made before the commencement date and initial direct costs incurred. Lease terms include options to extend or terminate the lease if it is reasonably certain they will be exercised. We include non-lease components for most asset classes, which are service-related costs that are not integral to the use of the asset, in the measurement of the ROU asset and lease liability.

Expense for operating leases and leases with a term of one year or less is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the derivation of benefit from use of the leased property. Variable lease payments are recognized in the period in which the related obligation is incurred and consist primarily of payments for purchases of electricity under contracted generation and are based on the electricity produced by those generating assets. Operating lease expense and variable lease payments are recorded to Purchased power and fuel expense for contracted generation or Operating and maintenance expense for all other lease agreements in the Statements of Operations and Comprehensive Income.

Income from operating leases, including subleases, is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the pattern in which income is earned over the term of the lease. Variable lease payments are recognized in the period in which the related obligation is performed and consist primarily of payments received from sales of electricity under contracted generation and are based on the electricity produced by those generating assets. Operating lease income and variable lease payments are recorded to Operating revenues in the Statements of Operations and Comprehensive Income.

Our operating leases consist primarily of contracted generation, real estate including office buildings, and vehicles and equipment. We generally account for contracted generation in which the generating asset is not renewable as a lease if the customer has dispatch rights and obtains substantially all of the economic benefits. For new agreements entered after January 1, 2019, we generally do not account for contracted generation in which the generating asset is renewable as a lease if the customer does not design the generating asset. We account for land right arrangements that provide for exclusive use as leases while shared use land arrangements are generally not leases.

See Note 11 — Leases for additional information.

Income Taxes

Deferred Federal and state income taxes are recorded on significant temporary differences between the book and tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred in the Consolidated Balance Sheets and are recognized in book income over the life of the related property. We account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. We recognize accrued interest related to unrecognized tax benefits in Interest expense, net or Other, net (interest income) and recognize penalties related to unrecognized tax benefits in Other, net in the Consolidated Statements of Operations and Comprehensive Income.

Cash and Cash Equivalents

We consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2020 and 2019, restricted cash and cash equivalents primarily represented the project-specific nonrecourse financing structures for debt service and financing of operations of the underlying entities. See Note 22 — Supplemental Financial Information for additional information.

Allowance for Credit Losses on Accounts Receivables

The allowance for credit losses reflects our best estimate of losses on the customers' accounts receivable balances based on historical experience, current information, and reasonable and supportable forecasts.

The allowance for credit losses for our retail customers is based on accounts receivable aging historical experience coupled with specific identification through a credit monitoring process, which considers current conditions and forward-looking information such as industry trends, macroeconomic factors, changes in the regulatory environment, external credit ratings, publicly available news, payment status, payment history, and the exercise of collateral calls. The allowance for credit losses for our wholesale customers is developed using a credit monitoring process, similar to that used for retail customers. When a wholesale customer's risk characteristics are no longer aligned with the pooled population, we use specific identification to develop an allowance for credit losses. Adjustments to the allowance for credit losses are recorded in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

We have certain non-customer receivables in Other deferred debits and other assets which primarily are with governmental agencies and other high-quality counterparties with no history of default. As such, the allowance for credit losses related to these receivables is not material. We monitor these balances and will record an allowance if there are indicators of a decline in credit quality.

Variable Interest Entities

We account for our investments in and arrangements with VIEs based on the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity has a controlling financial interest,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and

(2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

See Note 21 — Variable Interest Entities for additional information.

Inventories

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory. Fossil fuel, materials and supplies, and emissions allowances are generally included in inventory when purchased. Fossil fuel and emissions allowances are expensed to purchased power and fuel expense when used or sold. Materials and supplies generally includes generating plant materials and are expensed to operating and maintenance or capitalized to property, plant and equipment, as appropriate, when installed or used.

Debt and Equity Security Investments

Debt Security Investments. Debt securities are reported at fair value and classified as available-for-sale securities. Unrealized gains and losses, net of tax, are reported in OCI.

Equity Security Investments without Readily Determinable Fair Values. We have certain equity securities without readily determinable fair values. We have elected to use the practicability exception to measure these investments, defined as cost adjusted for changes from observable transactions for identical or similar investments of the same issuer, less impairment. Changes in measurement are reported in earnings.

Equity Security Investments with Readily Determinable Fair Values. We have certain equity securities with readily determinable fair values. For equity securities held in NDT funds, realized and unrealized gains and losses, net of tax, on our NDT funds associated with the Regulatory Agreement Units are included in Noncurrent payables to affiliates. Realized and unrealized gains and losses, net of tax, on our NDT funds associated with the Non-Regulatory Agreement Units are included in earnings. Our NDT funds are classified as current or noncurrent assets, depending on the timing of the decommissioning activities and income taxes on trust earnings. For all other equity securities with readily determinable fair values, realized and unrealized gains and losses are included in earnings. See Note 18 — Fair Value of Financial Assets and Liabilities and Note 10 — Asset Retirement Obligations for additional information.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. When appropriate, original cost also includes capitalized interest. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to Operating and maintenance expense as incurred.

Upon retirement, the cost of property is generally charged to accumulated depreciation in accordance with the composite and group methods of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to Operating and maintenance expense as incurred.

Capitalized Software. Certain costs, such as design, coding, and testing incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within Property, plant and equipment. Similar costs incurred for cloud-based solutions treated as service arrangements are capitalized within Other Current Assets and Deferred Debits and Other Assets. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements.

Capitalized Interest. During construction, we capitalize the costs of debt funds used to finance construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense. See Note 8 — Property, Plant and Equipment, Note 9 — Jointly Owned Electric Utility Plant and Note 22 — Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel

The cost of nuclear fuel is capitalized within Property, plant and equipment and charged to fuel expense using the unit-of-production method. Any potential future SNF disposal fees will be expensed through fuel expense. Additionally, certain on-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 19 — Commitments and Contingencies for additional information regarding the cost of SNF storage and disposal.

Nuclear Outage Costs

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to Operating and maintenance expense or capitalized to Property, plant and equipment (based on the nature of the activities) in the period incurred.

Depreciation and Amortization

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for dissimilar assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The estimated service lives are based on a combination of depreciation studies, historical retirements, site licenses and management estimates of operating costs and expected future energy market conditions. See Note 7 — Early Plant Retirements for additional information on the impacts of early plant retirements, Note 8 — Property, Plant and Equipment for additional information regarding depreciation, and Note 22 — Supplemental Financial Information for additional information regarding nuclear fuel and ARC.

Asset Retirement Obligations

We estimate and recognize a liability for our legal obligation to perform asset retirement activities even though the timing and/or methods of settlement may be conditional on future events. We generally update our nuclear decommissioning ARO annually, unless circumstances warrant more frequent updates, based on our annual evaluation of cost escalation factors and probabilities assigned to the multiple outcome scenarios within our probability-weighted discounted cash flow models. Our multiple outcome scenarios are generally based on decommissioning cost studies which are updated, on a rotational basis, for each of our nuclear units at least every five years, unless circumstances warrant more frequent updates. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income for Non-Regulatory Agreement Units and through a decrease in noncurrent payables to affiliates for Regulatory Agreement Units. See Note 10 — Asset Retirement Obligations for additional information.

Guarantees

If necessary, we recognize a liability at the time of issuance of a guarantee for the fair market value of the obligations we have undertaken by issuing the guarantee. The liability is reduced or eliminated as we are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 19 — Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets. We regularly monitor and evaluate the carrying value of long-lived assets and asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, or plans to dispose of a long-lived asset significantly before the end of its useful life. We determine if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. See Note 12 — Asset Impairments for additional information.

Equity Method Investments. We regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the entity in which we hold an investment recognizes an impairment loss, we would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt Security Investments. Declines in the fair value of debt security investments below the cost basis are reviewed to determine if such declines are other-than-temporary. If the decline is determined to be other-than-temporary, the amount of the impairment loss is included in earnings.

Equity Security Investments. Equity investments with readily determinable fair values are measured and recorded at fair value with any changes in fair value recorded through earnings. Investments in equity securities without readily determinable fair values are qualitatively assessed for impairment each reporting period. If it is determined that the equity security is impaired on the basis of the qualitative assessment, an impairment loss will be recognized in earnings to the amount by which the security's carrying amount exceeds its fair value.

Derivative Financial Instruments

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the NPNS. For derivatives intended to serve as economic hedges, changes in fair value are recognized in earnings each period. Amounts classified in earnings are included in Operating revenue, Purchased power and fuel, Interest expense, or Other, net in the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. While the majority of the derivatives serve as economic hedges, there are also derivatives entered into for proprietary trading purposes, subject to our Risk Management Policy, and changes in the fair value of those derivatives are recorded in revenue in the Consolidated Statements of Operations and Comprehensive Income. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing, or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction. On July 1, 2018, we de-designated our fair value and cash flow hedges.

As part of the energy marketing business, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. NPNS are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as NPNS are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting.

See Note 16 — Derivative Financial Instruments for additional information.

Retirement Benefits

Exelon sponsors defined benefit pension plans and OPEB plans for essentially all current employees. The plan obligations and costs of providing benefits under these plans are measured as of December 31. We account for our participation in Exelon's pension and OPEB plans by applying multi-employer accounting. Exelon allocates costs related to its pension and OPEB plans to its subsidiaries based on both active and retired employee participation in each plan. We include the service cost and non-service cost components in Operating and maintenance expense and Property, plant, and equipment, net in our consolidated financial statements. See Note 15 — Retirement Benefits for additional information.

New Accounting Standards

New Accounting Standards Adopted in 2020: In 2020, we adopted the following new authoritative accounting guidance issued by the FASB.

Impairment of Financial Instruments (Issued June 2016). Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects its current estimate of credit losses expected to be incurred over the life of the financial instrument based on historical experience, current conditions and reasonable and supportable forecasts. The standard was effective January 1, 2020 and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. This standard is primarily applicable to our trade accounts receivables balances. The guidance did not have a significant impact on our consolidated financial statements.

2. Mergers, Acquisitions, and Dispositions

CENG Put Option

We own a 50.01% membership interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to an 82% undivided ownership interest in Nine Mile Point Unit 2. CENG is 100% consolidated in our financial statements. See Note 21 — Variable Interest Entities for additional information.

On April 1, 2014, we entered into various agreements including a NOSA, an amended LLC Operating Agreement, an Employee Matters Agreement, and a Put Option Agreement, among others with EDF. Under the amended LLC Operating Agreement, CENG made a $400 million special distribution to EDF and committed to make preferred distributions to us until we have received aggregate distributions of $400 million plus a return of 8.50% per annum. Under the Put Option Agreement, EDF has the option to sell its 49.99% equity interest in CENG to us exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. On November 20, 2019, we received notice of EDF's intention to exercise the put option to sell its interest in CENG to us, and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period.

Under the terms of the Put Option Agreement, the purchase price is to be determined by agreement of the parties, or absent such agreement, by a third-party arbitration process. The third parties determining fair market value of EDF's 49.99% interest are to take into consideration all rights and obligations under the LLC Operating Agreement and Employee Matters Agreement including but not limited to our rights with respect to any unpaid aggregate preferred distributions and the related return. As of December 31, 2020, the total unpaid aggregate preferred distributions and related return owed to us is $619 million. At this time, we cannot reasonably predict the ultimate purchase price that will be paid to EDF for its interest in CENG. The transaction will require approval by the NYPSC and the FERC. The FERC approval was obtained on July 30, 2020. The process and regulatory approvals are expected to close in the second half of 2021.

Agreement for Sale of Our Solar Business

On December 8, 2020, we entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of our solar business, including 360 megawatts of generation in operation or under construction across more than 600 sites across the United States. Under the terms of the transaction, the purchase price is $810 million, subject to certain working capital and other post-closing adjustments. We will retain certain solar assets not included in this agreement, primarily Antelope Valley.

As a result of the transaction, in the fourth quarter of 2020, we reclassified the solar assets and liabilities in the Consolidated Balance Sheets as held for sale. The transaction is expected to result in an estimated pre-tax gain ranging from $75 million to $125 million. The gain will be recorded in Gain on sales of assets and businesses in the Consolidated Statements of Operations and Comprehensive Income upon completion of the transaction. Completion of the transaction contemplated by the sale agreement is subject to the satisfaction of several closing conditions and is expected to occur in the first half of 2021. See Note 17 — Debt and Credit Agreements for additional information on the SolGen nonrecourse debt included as part of the transaction.

Disposition of Oyster Creek

On July 31, 2018, we entered into an agreement with Holtec and its indirect wholly owned subsidiary, OCEP, for the sale and decommissioning of Oyster Creek located in Forked River, New Jersey, which permanently ceased generation operations on September 17, 2018. Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions, including approval of the license transfer from the NRC and other regulatory approvals, and a private letter ruling from the IRS, which were satisfied in the second quarter 2019. The sale was completed on July 1, 2019. We recognized a loss on the sale in the third quarter of 2019, which was immaterial.

Under the terms of the transaction, we transferred to OCEP substantially all the assets associated with Oyster Creek, including assets held in NDT funds, along with the assumption of liability for all responsibility for the site, including full decommissioning and ongoing management of spent fuel until the spent fuel is moved offsite. The terms of the transaction also include various forms of performance assurance for the obligations of OCEP to timely complete the required decommissioning, including a parental guaranty from Holtec for all performance and payment obligations of OCEP, and a requirement for Holtec to deliver a letter of credit to us upon the occurrence of specified events.

Upon remeasurement of the Oyster Creek ARO, we recognized an $84 million and a $9 million pre-tax charge to Operating and maintenance expense in 2018 and in 2019, respectively. See Note 10 — Asset Retirement Obligations for additional information.

Disposition of Electrical Contracting Business

On February 28, 2018, we completed the sale of our interest in an electrical contracting business that primarily installs, maintains, and repairs underground and high-voltage cable transmission and distribution systems for $87 million, resulting in a pre-tax gain which is included within Gain on sales of assets and businesses in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2018.

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3. Regulatory Matters

The following matters below discuss the status of our material regulatory and legislative proceedings.

Illinois Regulatory Matters

Zero Emission Standard. Pursuant to FEJA, on January 25, 2018, the ICC announced that our 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.

We executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue with compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. The ZEC price was initially established at $16.50 per MWh of production, subject to annual future adjustments determined by the IPA for specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices. Illinois utilities are required to purchase all ZECs delivered by the zero-emissions nuclear-powered generating facilities, subject to annual cost caps. For the initial delivery year, June 1, 2017 to May 31, 2018, and subsequent delivery year, June 1, 2018 to May 31, 2019, the ZEC annual cost cap was set at $235 million. For subsequent delivery years, the IPA-approved targeted ZEC procurement amounts will change based on forward energy and capacity prices. ZECs delivered to Illinois utilities in excess of the annual cost cap may be paid in subsequent years if the payments do not exceed the prescribed annual cost cap for that year. During the first quarter of 2018, we recognized $150 million of revenue related to ZECs generated from June 1, 2017 through December 31, 2017.

New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that provides 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 legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey will be required to purchase those ZECs. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. Upon approval, we began recognizing revenue for the sale of New Jersey ZECs in the month they are generated and have recognized $69 million and $53 million for the year ended December 31, 2020 and 2019, respectively. On May 15, 2019, New Jersey Rate Counsel appealed the NJBPU's decision to the New Jersey Superior Court. Briefing has been completed, and on December 9, 2020, an oral argument took place. On October 1, 2020, PSEG and us filed applications seeking ZECs for the second eligibility period (June 2022 through May 2025). The NJBPU will act on the applications by the end of April 2021. We cannot predict the outcome of the appeal. See Note 7 — Early Plant Retirements for additional information related to Salem.

New York Regulatory Matters

New York Clean Energy Standard. On August 1, 2016, the NYPSC issued an order establishing the New York CES, a component of which is a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC to be our FitzPatrick, Ginna, and Nine Mile Point nuclear facilities.

On November 30, 2016 (as amended on January 13, 2017), a group of parties filed a Petition in New York State court seeking to invalidate the ZEC program, which argued that the NYPSC did not have authority to establish the program, that it violated state environmental law and that it violated certain technical provisions of the State Administrative Procedures Act when adopting the ZEC program. On January 22, 2018, the court dismissed the environmental claims and the majority of the plaintiffs from the case but denied the motions to dismiss with respect to the remaining five plaintiffs and claims, without commenting on the merits of the case. On October 8, 2019, the court dismissed all remaining claims. The petitioners filed a notice of appeal on November 4, 2019 and originally had until May 4, 2020 to file their brief. Due to COVID-19 related restrictions, the court extended the deadline to July 29, 2020. Petitioners did not file a brief by the deadline, so the case is deemed dismissed. Petitioners are permitted up to one year from July 29, 2020 to file a motion to vacate the dismissal if they can show good cause for the delay.

See Note 7 — Early Plant Retirements for additional information related to Ginna and Nine Mile Point.

New England Regulatory Matters

Mystic Units 8 & 9 and Everett Marine Terminal Cost of Service Agreement. On March 29, 2018, we notified grid operator ISO-NE of our plans to early retire Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. On May 16, 2018, we made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 & 9 for the period between June 1, 2022 — May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service compensation, reflecting a number of adjustments to the annual fixed revenue requirement, and allowing for recovery of a substantial portion of the costs associated with the adjacent Everett Marine Terminal acquired in October 2018. Those adjustments were reflected in a compliance filing made on March 1, 2019. In the December 20, 2018 order, FERC also directed a paper hearing on ROE using a new methodology. On January 22, 2019, Generation and several other parties filed requests for rehearing of certain findings in the order.

On July 17, 2020, FERC issued three orders, which together affirmed the recovery of key elements of Mystic's cost of service compensation, including recovery of costs associated with the operation of the Everett Marine Terminal. FERC directed a downward adjustment to the rate base for Mystic Units 8 and 9, the effect of which will be partially offset by elimination of a crediting mechanism for third party gas sales during the term of the cost of service agreement. A compliance filing was submitted on September 15, 2020 and is pending. Several parties filed protests to the compliance filing on the issue of how gross plant in-service was calculated, and we filed an answer to the protests on October 21, 2020. On July 28, 2020, FERC ordered additional briefings in the ROE proceeding. On December 21, 2020, FERC issued an order on rehearing of the three July 17, 2020 orders, clarifying several cost of service provisions.

On August 25, 2020, a group of New England generators filed a complaint seeking to extend the scope of the claw back provision in the cost-of-service agreement, whereby we would refund certain amounts recovered during the term of the cost of service if it returns to market afterwards. On September 14, 2020, we filed an answer to the complaint arguing that the complaint is procedurally improper and a collateral attack on existing FERC orders, and pointing out that the ISO-NE tariff contains protections against the New England generators' concerns that they failed to mention. On September 28, 2020, New England generators filed an answer to our answer. We cannot predict the outcome of this proceeding.

On June 10, 2020, we filed a complaint with FERC against ISO-NE on the grounds that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic for transmission security for the 2024 to 2025 Capacity Commitment Period (FCA 15) and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic should have been filed with FERC for approval. On July 27, 2020, ISO-NE issued a memo to NEPOOL announcing its determination pursuant to its unfiled planning procedures that Mystic Units 8 and 9 are not needed for FCA 15 for transmission security. It had previously determined Mystic Units 8 and 9 are not needed for fuel security. On August 17, 2020, FERC issued an order denying the complaint. On September 16, 2020, we filed a request for rehearing with FERC. On October 19, 2020, FERC denied rehearing by operation of law and on December 18, 2020, we appealed to the U.S. Court of Appeals for the D.C. Circuit. The timing and the outcome of this proceeding is uncertain.

See Note 7 — Early Plant Retirements and Note 12 — Asset Impairments for additional information on the impacts of our August 2020 decision to retire Mystic Units 8 & 9 upon expiration of the cost of service agreement.

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Federal Regulatory Matters

PJM and NYISO MOPR Proceedings. PJM and NYISO capacity markets include a MOPR. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a state government-provided financial support program — resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the MOPR in PJM applied only to certain new gas-fired resources. Currently, the MOPR in NYISO applies only to certain resources in downstate New York.

For our facilities in PJM and NYISO that are currently receiving ZEC compensation, an expanded MOPR would require exclusion of ZEC compensation when bidding into future capacity auctions, resulting in an increased risk of these facilities not receiving capacity revenues in future auctions.

On December 19, 2019, FERC required PJM to broadly apply the MOPR to all new and existing resources including nuclear, renewables, demand response, energy efficiency, storage, and all resources owned by vertically-integrated utilities. This greatly expands the breadth and scope of PJM's MOPR, which is effective as of PJM's next capacity auction. While FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources.

FERC provided no new mechanism for accommodating state-supported resources other than the existing FRR mechanism (under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone). In response to FERC's order, PJM submitted a compliance filing on March 18, 2020 wherein PJM proposed tariff language interpreting and implementing FERC's directives, and proposed a schedule for resuming capacity auctions that is contingent on the timing of FERC's action on the compliance filing.

On April 16, 2020, FERC issued an order largely denying most requests for rehearing of FERC's December 2019 order but granting a few clarifications that required an additional PJM compliance filing which PJM submitted on June 1, 2020.

On October 15, 2020, FERC issued an order denying requests for rehearing of its April 16, 2020 order and accepting PJM's two compliance filings, subject to a further compliance filing to revise minor aspects of the proposed MOPR methodology. As part of that order, FERC also accepted PJM's proposal to condense the schedule of activities leading up to the next capacity auction. In November 2020, PJM announced that it will conduct its next capacity auction beginning on May 19, 2021 and ending on May 25, 2021 and will post the results on June 2, 2021.

Because neither Illinois nor New Jersey have implemented an FRR program in their PJM zones, the MOPR will apply in that next capacity auction to our owned or jointly owned nuclear plants in those states receiving a benefit under the Illinois ZES, or the New Jersey ZEC program, as applicable, increasing the risk that those units may not clear the capacity market.

We are currently working with PJM and other stakeholders to pursue the FRR option as an alternative to the PJM capacity auction. If Illinois implements the FRR option, our Illinois nuclear plants could be removed from PJM's capacity auction and instead supply capacity, and be compensated under the FRR program, which has the potential to mitigate the current economic distress being experienced by our nuclear plants in Illinois, as discussed in Note 7 — Early Plant Retirements. Implementing the FRR program in Illinois will require both legislative and regulatory changes. Whether legislation is needed in New Jersey would depend on how the state chooses to structure an FRR program. We cannot predict whether or when such legislative and regulatory changes can be implemented.

On February 20, 2020, FERC issued an order rejecting requests to expand NYISO's version of the MOPR (referred to as buyer-side mitigation rules) beyond its current limited applicability to certain resources in downstate. However, on October 14, 2020, two natural gas-fired generators in New York filed a complaint at FERC seeking to expand the MOPR in NYISO to apply to all resources, new and existing, across the entire NYISO market. We are strenuously opposing expansion of FERC's MOPR policies in the NYISO market. While it is too early in the proceeding to predict its outcome and there are significant differences between the NYISO and PJM markets that would justify a different result, if FERC follows its MOPR precedent in PJM and applies the MOPR in NYISO broadly as requested in the complaint, our facilities in NYISO that are receiving ZEC compensation may be at increased risk of not clearing the capacity auction.

If our state-supported nuclear plants in PJM or NYISO are subjected to the MOPR or equivalent without compensation under an FRR or similar program, it could have a material adverse impact on our financial statements, which we cannot reasonably estimate at this time.

Operating License Renewals

Conowingo Hydroelectric Project. On August 29, 2012, we submitted a hydroelectric license application to FERC for a new license for the Conowingo Hydroelectric Project (Conowingo). In connection with our efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act (401 Certification) from MDE for Conowingo, we have been working with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 21, 2016, we and the U.S. Fish and Wildlife Service of the U.S. Department of the Interior executed a settlement agreement (DOI Settlement) resolving all fish passage issues between the parties.

On April 27, 2018, MDE issued its 401 Certification for Conowingo. As issued, the 401 Certification contains numerous conditions, including those relating to reduction of nutrients from upstream sources, removal of all visible trash and debris from upstream sources, and implementation of measures relating to fish passage, which could have a material, unfavorable impact on our financial statements through an increase in capital expenditures and operating costs if implemented. On May 25, 2018, we filed complaints in federal and state court, along with a petition for reconsideration with MDE, alleging that the conditions are unfair and onerous and in violation of MDE regulations and state, federal, and constitutional law. We also requested that FERC defer the issuance of the federal license while these significant state and federal law issues are pending. On February 28, 2019, we filed a Petition for Declaratory Order with FERC requesting that FERC issue an order declaring that MDE waived its right to issue a 401 Certification for Conowingo because it failed to timely act on Conowingo’s 401 Certification application and requesting that FERC decline to include the conditions required by MDE in April 2018.

On October 29, 2019, we and MDE filed with FERC a Joint Offer of Settlement (Offer of Settlement) that would resolve all outstanding issues relating to the 401 Certification. Pursuant to the Offer of Settlement, the parties submitted Proposed License Articles to FERC to be incorporated by FERC into the new license in accordance with FERC’s discretionary authority under the Federal Power Act. Among the Proposed License Articles are modifications to river flows to improve aquatic habitat, eel passage improvements, and initiatives to support rare, threatened and endangered wildlife. If FERC approves the Offer of Settlement and incorporates the Proposed License Articles into the new license without modification, then MDE would waive its rights to issue a 401 Certification and we would agree, pursuant to a separate agreement with MDE (MDE Settlement), to implement additional environmental protection, mitigation, and enhancement measures over the anticipated 50-year term of the new license. These measures address mussel restoration and other ecological and water quality matters, among other commitments. Our commitments under the various provisions of the Offer of Settlement and MDE Settlement are not effective unless and until FERC approves the Offer of Settlement and issues the new license with the Proposed License Articles.

The financial impact of the DOI and MDE Settlements and other anticipated license commitments are estimated to be $11 million to $14 million per year, on average, recognized over the new license term, including capital and operating costs. The actual timing and amount of the majority of these costs are not currently fixed and will vary from year to year throughout the life of the new license. We cannot currently predict when FERC will issue the new license. As of December 31, 2020, $45 million of direct costs associated with Conowingo licensing efforts have been capitalized. Our current depreciation provision for Conowingo assumes renewal of the FERC license.

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Peach Bottom Units 2 and 3. On July 10, 2018, we submitted a second 20-year license renewal application with the NRC for Peach Bottom Units 2 and 3, which was approved on March 6, 2020. Peach Bottom Units 2 and 3 are now licensed to operate through 2053 and 2054, respectively. See Note 8 — Property, Plant and Equipment for additional information regarding the estimated useful life and depreciation provisions for Peach Bottom.

4. Revenue from Contracts with Customers

We recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that we expect to be entitled to in exchange for those goods or services. Our primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The performance obligations, revenue recognition, and payment terms associated with these sources of revenue are further discussed in the table below. There are no significant financing components for these sources of revenue.

Unless otherwise noted, for each of the significant revenue categories and related performance obligations described below, we have the right to consideration from the customer in an amount that corresponds directly with the value transferred to the customer for the performance completed to date. Therefore, we generally recognize revenue in the amount for which we have the right to invoice the customer. As a result, there are generally no significant judgments used in determining or allocating the transaction price.

Revenue Source	Description	Performance Obligation	Timing of Revenue Recognition	Payment Terms
Competitive Power Sales	Sales of power and other energy-related commodities to wholesale and retail customers across multiple geographic regions through its customer-facing business, Constellation.	Various including the delivery of power (generally delivered over time) and other energy-related commodities such as capacity (generally delivered over time), ZECs, RECs or other ancillary services (generally delivered at a point in time).	Concurrently as power is generated for bundled power sale contracts.[a]	Within the month following delivery to the customer.
Competitive Natural Gas Sales	Sales of natural gas on a full requirement basis or for an agreed upon volume to commercial and residential customers.	Delivery of natural gas to the customer.	Over time as the natural gas is delivered and consumed by the customer.	Within the month following delivery to the customer.
Other Competitive Products and Services	Sales of other energy-related products and services such as long-term construction and installation of energy efficiency assets and new power generating facilities, primarily to commercial and industrial customers.	Construction and/or installation of the asset for the customer.	Revenues and associated costs are recognized throughout the contract term using an input method to measure progress towards completion.[b]	Within 30 or 45 days from the invoice date.

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(a) Certain contracts may contain limits on the total amount of revenue we are able to collect over the entire term of the contract. In such cases, we estimate the total consideration expected to be received over the term of the contract net of the constraint and allocate the expected consideration to the performance obligations in the contract such that revenue is recognized ratably over the term of the entire contract as the performance obligations are satisfied.

(b) The method recognizes revenue based on the various inputs used to satisfy the performance obligation, such as costs incurred and total labor hours expended. The total amount of revenue that will be recognized is based on the agreed upon contractually-stated amount. The average contract term for these projects is approximately 18 months.

We incur incremental costs in order to execute certain retail power and gas sales contracts. These costs, which primarily relate to retail broker fees and sales commissions, are capitalized when incurred as contract acquisition costs and were immaterial as of December 31, 2020 and 2019.

Contract Balances

Contract Assets

We record contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before we have an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. We record contract assets and contract receivables within Other current assets and Customer accounts receivable, net, respectively, within the Consolidated Balance Sheets. The following table provides a rollforward of the contract assets reflected in our Consolidated Balance Sheets.

	Contract Assets
Balance as of December 31, 2018	$ 187
Amounts reclassified to receivables	(143)
Revenues recognized	130
Balance at December 31, 2019	174
Amounts reclassified to receivables	(86)
Revenues recognized	68
Contract assets reclassified as held for sale[a]	(12)
Balance at December 31, 2020	$ 144

(a) Represents contract assets related to our solar business, which were classified as held for sale as a result of the sale agreement. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

Contract Liabilities

We record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. We record contract liabilities within Other current liabilities and Other non-current liabilities within the Consolidated Balance Sheets. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans, solar panel leases, and the Illinois ZEC program that introduces a cap on the total consideration to be received by us. The following table provides a rollforward of the contract liabilities reflected in our Consolidated Balance Sheets.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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	Contract Liabilities
Balance as of December 31, 2017	$ 35
Consideration received or due	465
Revenues recognized	(458)
Balance as of December 31, 2018	42
Consideration received or due	287
Revenues recognized	(258)
Balance at December 31, 2019	71
Consideration received or due	282
Revenues recognized	(266)
Contracts liabilities reclassified as held for sale[(a)]	(3)
Balance at December 31, 2020	$ 84

(a) Represents contract liabilities related to our solar business, which were classified as held for sale as a result of the sale agreement. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

The following table reflects revenues recognized in the years ended December 31, 2020, 2019 and 2018, which were included in contract liabilities at December 31, 2019, 2018, and 2017, respectively:

	2020	2019	2018
Revenues recognized	$64	$32	$11

Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of December 31, 2020. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years. This disclosure excludes our power and gas sales contracts as they contain variable volumes and/or variable pricing.

	2021	2022	2023	2024	2025 and thereafter	Total
Remaining performance obligations	$352	$124	$55	$34	$243	$808

Revenue Disaggregation

We disaggregate the revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 5 — Segment Information for the presentation of revenue disaggregation.

5. Segment Information

Operating segments are determined based on information used by the CODM in deciding how to evaluate performance and allocate resources.

We have five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and all other power regions referred to collectively as “Other Power Regions.”

The basis for our reportable segments is the integrated management of our 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). Our hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of our five 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 and the United States footprint of MISO, excluding MISO's Southern Region.
- **New York** represents operations within NYISO.
- **ERCOT** represents operations within Electric Reliability Council of Texas.
- **Other Power Regions:**
- **New England** represents operations within ISO-NE.
- **South** represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM.
- **West** represents operations in the WECC, which includes CAISO.
- **Canada** represents operations across the entire country of Canada and includes AESO, OIESO, and the Canadian portion of MISO.

The CODM evaluates the performance of our electric business activities and allocates resources based on Revenues Net of Purchased Power and Fuel Expense (RNF). We believe that RNF is a useful measurement of operational performance. RNF 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. Our operating revenues include all sales to third parties and affiliated sales to the Exelon's utility subsidiaries. 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 our owned generation and fuel costs associated with tolling agreements. The results of our other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to our overall operating revenues or results of operations. Further, our unrealized mark-to-market gains and losses on economic hedging activities and our amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. We do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

The following tables disaggregate the revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. The disaggregation of revenues reflects our two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. The following tables also show the reconciliation of reportable segment revenues and RNF to our total revenues and RNF for the years ended December 31, 2020, 2019, and 2018.

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	2020				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 4,785	$ (168)	$ 4,617	$ 28	$ 4,645
Midwest	3,717	312	4,029	(5)	4,024
New York	1,444	(12)	1,432	(1)	1,431
ERCOT	735	198	933	25	958
Other Power Regions	3,586	463	4,049	(47)	4,002
Total Competitive Businesses Electric Revenues	$14,267	$ 793	$15,060	$ —	$15,060
Competitive Businesses Natural Gas Revenues	1,283	720	2,003	—	2,003
Competitive Businesses Other Revenues[c]	355	185	540	—	540
Total Consolidated Operating Revenues	$15,905	$1,698	$17,603	$ —	$17,603

	2019				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 5,053	$ 17	$ 5,070	$ 4	$ 5,074
Midwest	4,095	232	4,327	(34)	4,293
New York	1,571	25	1,596	—	1,596
ERCOT	768	229	997	16	1,013
Other Power Regions	3,687	608	4,295	(49)	4,246
Total Competitive Businesses Electric Revenues	$15,174	$1,111	$16,285	$(63)	$16,222
Competitive Businesses Natural Gas Revenues	1,446	702	2,148	62	2,210
Competitive Businesses Other Revenues[c]	440	51	491	1	492
Total Consolidated Operating Revenues	$17,060	$1,864	$18,924	$ —	$18,924

	2018				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 5,241	$ 233	$ 5,474	$ 13	$ 5,487
Midwest	4,527	190	4,717	(11)	4,706
New York	1,723	(36)	1,687	—	1,687
ERCOT	572	560	1,132	1	1,133
Other Power Regions	3,530	871	4,401	(66)	4,335
Total Competitive Businesses Electric Revenues	$15,593	$1,818	$17,411	$(63)	$17,348
Competitive Businesses Natural Gas Revenues	1,524	1,194	2,718	62	2,780
Competitive Businesses Other Revenues[c]	510	(202)	308	1	309
Total Consolidated Operating Revenues	$17,627	$2,810	$20,437	$ —	$20,437

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(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to Exelon's utility subsidiaries.

(b) Includes revenues from derivatives and leases.

(c) Represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market gains of $110 million and losses of $4 million and $262 million for the years ended December 31, 2020, 2019, and 2018, respectively, and the elimination of intersegment revenues.

	2020			2019			2018		
	RNF from external customers[(a)]	Intersegment RNF	Total RNF	RNF from external customers[(a)]	Intersegment RNF	Total RNF	RNF from external customers[(a)]	Intersegment RNF	Total RNF
Mid-Atlantic	$2,174	$ 30	$2,204	$2,637	$ 18	$2,655	$3,022	$ 51	$3,073
Midwest	2,902	—	2,902	2,994	(32)	2,962	3,112	23	3,135
New York	983	14	997	1,081	13	1,094	1,112	10	1,122
ERCOT	407	19	426	338	(30)	308	501	(243)	258
Other Power Regions	759	(94)	665	694	(74)	620	883	(154)	729
Total RNF for Reportable Segments	$7,225	$(31)	$7,194	$7,744	$(105)	$7,639	$8,630	$(313)	$8,317
Other[(b)]	793	31	824	324	105	429	114	313	427
Total RNF	$8,018	$ —	$8,018	$8,068	$ —	$8,068	$8,744	$ —	$8,744

(a) Includes purchases and sales from/to third parties and affiliated sales to Exelon's utility subsidiaries.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Primarily includes:

- unrealized mark-to-market gains of $295 million and losses of $215 million and $319 million for the years ended December 31, 2020, 2019, and 2018, respectively;
- accelerated nuclear fuel amortization associated with the announced early plant retirements as discussed in Note 7 — Early Plant Retirements of $60 million, $13 million, and $57 million in for the years ended December 31, 2020, 2019, and 2018, respectively; and
- the elimination of intersegment RNF.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

6. Accounts Receivable

Allowance for Credit Losses on Accounts Receivable

The following table presents the rollforward of Allowance for Credit Losses on Customer Accounts Receivable for the year ended December 31, 2020.

	Allowance for Credit Losses
Balance as of December 31, 2019	$80
Plus: Current Period Provision for Expected Credit Losses	13
Less: Write-offs, net of recoveries[(a)]	5
Less: Sale of customer accounts receivable[(b)]	56
Balance as of December 31, 2020	$32

(a) Recoveries were not material.

(b) See below for additional information on the sale of customer accounts receivable in the second quarter of 2020.

Unbilled Customer Revenue

We recorded $258 million and $807 million of unbilled customer revenues in Customer accounts receivables, net in the Consolidated Balance Sheets as of December 31, 2020 and 2019, respectively.

Sales of Customer Accounts Receivable

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly-owned by us, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivable (the Facility). The Facility, whose maximum capacity is $750 million, is scheduled to expire on April 7, 2021, unless renewed by the mutual consent of the parties in accordance with its terms. Under the Facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in the consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the DPP, which is reflected in Other current assets on our Consolidated Balance Sheet.

On April 8, 2020, we derecognized and transferred approximately $1.2 billion of receivables at fair value to the Purchasers in exchange for approximately $500 million in cash purchase price and $650 million of DPP. On February 17, 2021, we received additional cash of $250 million from the Purchasers for the remaining capacity in the Facility.

The following table summarizes the impact of the sale of certain receivables:

	As of December 31, 2020
Derecognized receivables transferred at fair value[(a)]	$1,139
Cash proceeds received	500
DPP	639

(a) Includes additional customer accounts receivable sold into the Facility of $6,608 million since the start of the financing agreement.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

	For the year ended December 31, 2020
Loss on sale of receivables[(a)]	$30

(a) Reflected in Operating and maintenance expense on our Consolidated Statement of Operations and Comprehensive Income.

	For the year ended December 31, 2020
Proceeds from new transfers	$2,816
Cash collections received on DPP	3,771
Cash collections reinvested in the Facility	6,587

Our risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred, which have historically been and are expected to be immaterial. We continue to service the receivables sold in exchange for a servicing fee. We did not record a servicing asset or liability as the servicing fees were immaterial.

We recognize the cash proceeds received upon sale in Net cash provided by operating activities in our Consolidated Statement of Cash Flows. The collection and reinvestment of DPP is recognized in Net cash provided by investing activities of the Consolidated Statement of Cash Flows.

See Note 18 — Fair Value of Financial Assets and Liabilities and Note 21 — Variable Interest Entities for additional information.

Other Purchases and Sales of Customer and Other Accounts Receivables

We are required, under supplier tariffs in ISO-NE, MISO, NYISO, and PJM, to sell customer and other receivables to utility companies, which include Exelon's utility subsidiaries. The following table presents the total receivables sold for the year ended December 31, 2020.

	For the year ended December 31, 2020
Total Receivables Sold	$824
Related Party Transactions:	
Receivables sold to Exelon's utility subsidiaries	252

7. Early Plant Retirements

We continuously evaluate factors that affect the current and expected economic value of our plants, including, but not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for benefits they provide through their carbon-free emissions, reliability, or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and NDT fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

In 2015 and 2016, we identified the Clinton and Quad Cities nuclear plants in Illinois, Ginna and Nine Mile Point nuclear plants in New York, and TMI nuclear plant in Pennsylvania as having the greatest risk of early retirement based on economic valuation and other factors. In 2017, PSEG made public similar financial challenges facing its New Jersey nuclear plants, including Salem, of which we own a 42.59% ownership interest. PSEG is the operator of Salem and also has the decision-making authority to retire Salem.

Assuming the continued effectiveness of the Illinois ZES, New Jersey ZEC program, and the New York CES, we and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Salem, Ginna, or Nine Mile Point to be at heightened risk for early retirement. However, to the extent the Illinois ZES, New Jersey ZEC program, or the New York CES do not operate as expected over their full terms, each of these plants, in addition to FitzPatrick, would be at heightened risk for early retirement, which could have a material impact on our future financial statements. In addition, FERC’s December 19, 2019 order on the MOPR in PJM may undermine the continued effectiveness of the Illinois ZES and the New Jersey ZEC program unless Illinois and New Jersey implement an FRR mechanism under which our plants in these states would be removed from PJM’s capacity auction. See Note 3 — Regulatory Matters for additional information on the Illinois ZES, New Jersey ZEC program, New York CES, and FERC’s December 19, 2019 order on the MOPR in PJM.

In Pennsylvania, the TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020 – 2021 planning year, the third consecutive year that TMI failed to clear the PJM base residual capacity auction and on May 30, 2017, based on these capacity auction results, prolonged periods of low wholesale power prices, and the absence of federal or state policies that place a value on nuclear energy for its ability to produce electricity without air pollution, we announced that we would permanently cease generation operations at TMI. On September 20, 2019, we permanently ceased generation operations at TMI.

Dresden, Byron, and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution. The May 2018 PJM capacity auction for the 2021 – 2022 planning year resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood. While all of LaSalle’s capacity did clear in the 2021 – 2022 planning year auction, we have become increasingly concerned about the economic viability of this plant as well in a landscape where energy market prices remain depressed and energy market rules remain fatally flawed.

On August 27, 2020, we announced that we intend to permanently cease generation operations at Byron in September 2021 and at Dresden in November 2021. The current NRC licenses for Byron Units 1 and 2 expire in 2044 and 2046, respectively, and the licenses for Dresden Units 2 and 3 expire in 2029 and 2031, respectively.

As a result of the decision to early retire Byron and Dresden, we recognized certain one-time charges for the year ended December 31, 2020 related to materials and supplies inventory reserve adjustments, employee-related costs, including severance benefit costs further discussed below, and construction work-in-progress impairments, among other items. In addition, as a result of the decisions to early retire Byron and Dresden, there are ongoing annual financial impacts stemming from shortening the expected economic useful lives of these nuclear plants primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and changes in ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date. See Note 10 — Asset Retirement Obligations for additional information on changes to the nuclear decommissioning ARO balance and Note 12 — Asset Impairments for impairment assessment considerations given to the Midwest asset group as a result of the early retirement decision. The total impact on the Consolidated Statements of Operations and Comprehensive Income is summarized in the table below.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Income statement expense (pre-tax)	2020[a]	2019[b]	2018[c]
Depreciation and amortization			
Accelerated depreciation[d]	$ 895	$216	$539
Accelerated nuclear fuel amortization	60	13	57
Operating and maintenance			
One-time charges	255	—	32
Other charges[e]	34	(53)	—
Contractual offset[f]	(364)	—	—
Total	$ 880	$176	$628

(a) Reflects expense for Byron and Dresden.

(b) Reflects expense for TMI.

(c) Reflects expense for TMI and Oyster Creek.

(d) Includes the accelerated depreciation of plant assets including any ARC.

(e) For Dresden, reflects the net impacts associated with the remeasurement of the ARO. For TMI, primarily reflects the net impacts associated with the remeasurement of the ARO. See Note 10 — Asset Retirement Obligations for additional information.

(f) Reflects contractual offset for ARO accretion, ARC depreciation, and net impacts associated with the remeasurement of the ARO. For Byron and Dresden, based on the regulatory agreement with the ICC, decommissioning-related activities in 2020 have been offset within the Consolidated Statements of Operations and Comprehensive Income. The offset in 2020 resulted in an adjustment to the noncurrent payables to ComEd. See Note 10 — Asset Retirement Obligations for additional information.

Severance benefit costs will be provided to employees impacted by the early retirements of Byron and Dresden, to the extent they are not redeployed to other nuclear plants. For the year ended December 31, 2020, we recorded severance expense of $81 million within Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income. The final amount of severance benefit costs will depend on the specific employees severed.

The following table provides the balance sheet amounts as of December 31, 2020 for our significant assets and liabilities associated with the Braidwood and LaSalle nuclear plants. Current depreciation provisions are based on the estimated useful lives of these nuclear generating stations, which reflect the first renewal of the operating licenses.

	Braidwood	LaSalle	Total
Asset Balances			
Materials and supplies inventory, net	$84	$106	$ 190
Nuclear fuel inventory, net	120	285	405
Completed plant, net	1,397	1,590	2,987
Construction work in progress	31	30	61
Liability Balances			
Asset retirement obligation	(570)	(954)	(1,524)
NRC License First Renewal Term	2046 (Unit 1)	2042 (Unit 1)	
	2047 (Unit 2)	2043 (Unit 2)	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

We continue to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level. The absence of such solutions or reforms could result in future impairments of the Midwest asset group, or accelerated depreciation for specific plants over their shortened estimated useful lives, both of which could have a material unfavorable impact on our future results of operations.

Other Generation

In March 2018, we notified ISO-NE of our plans to early retire, among other assets, the Mystic Generating Station's units 8 and 9 (Mystic 8 and 9) absent regulatory reforms to properly value reliability and regional fuel security. Thereafter, ISO-NE identified Mystic 8 and 9 as being needed to ensure fuel security for the region and entered into a cost of service agreement with these two units for the period between June 1, 2022 – May 31, 2024. The agreement was approved by the FERC in December 2018.

On June 10, 2020, we filed a complaint with FERC against ISO-NE stating that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic 8 and 9 for transmission security for the 2024 to 2025 Capacity Commitment Period (FCA 15) and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic 8 and 9 should have been filed with FERC for approval. On August 17, 2020, FERC issued an order denying the complaint. As a result, on August 20, 2020, we determined we will permanently cease generation operations at Mystic 8 and 9 at the expiration of the cost of service commitment in May 2024. See Note 3 — Regulatory Matters for additional discussion of Mystic's cost of service agreement.

As a result of the decision to early retire Mystic 8 and 9, we recognized $22 million of one-time charges for the year ended December 31, 2020, related to materials and supplies inventory reserve adjustments, among other items. In addition, there are annual financial impacts stemming from shortening the expected economic useful life of Mystic 8 and 9 primarily related to accelerated depreciation of plant assets. We recorded incremental Depreciation and amortization expense of $26 million for the year ended December 31, 2020. See Note 12 — Asset Impairments for impairment assessment considerations of the New England Asset Group.

8. Property, Plant and Equipment

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2020 and 2019:

Asset Category	December 31, 2020	December 31, 2019
Electric	$29,724	$29,839
Nuclear fuel[(a)]	5,399	5,656
Construction work in progress	450	702
Other property, plant, and equipment	11	13
Total property, plant, and equipment	35,584	36,210
Less: accumulated depreciation[(b)]	13,370	12,017
Property, plant, and equipment, net	$22,214	$24,193

(a) Includes nuclear fuel that is in the fabrication and installation phase of $939 million and $1,025 million at December 31, 2020 and 2019, respectively.

(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,774 million and $2,867 million as of December 31, 2020 and 2019, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

The following table presents the average service life for each asset category in number of years:

Asset Category	Average Service Life (years)
Electric	1 – 58
Nuclear fuel	1 – 8
Other property, plant, and equipment	1 – 10

Depreciation provisions are based on the estimated useful lives of the stations, which reflect the first renewal of the operating licenses for all of our operating nuclear generating stations except for Clinton, Byron, Dresden and Peach Bottom. Clinton depreciation provisions are based on an estimated useful life through 2027, which is the last year of the Illinois ZES. Peach Bottom depreciation provisions are based on estimated useful life of 2053 and 2054 for Unit 2 and Unit 3, respectively, which reflects the second renewal of its operating licenses. Beginning August 2020, Byron, Dresden, and Mystic depreciation provisions were based on their announced shutdown dates of September 2021, November 2021, and May 2024, respectively. See Note 3 — Regulatory Matters for additional information regarding license renewals and the Illinois ZECs and Note 7 — Early Plant Retirements for additional information on the impacts of early plant retirements.

The following table presents the annual depreciation rates for each asset category. Nuclear fuel amortization is charged to fuel expense using the unit-of-production method and not included in the below table.

	Annual Depreciation Rates		
	December 31, 2020	December 31, 2019	December 31, 2018
Electric	6.11%	4.35%	5.37%

Capitalized Interest

The following table summarizes capitalized interest by year:

	December 31, 2020	December 31, 2019	December 31, 2018
Capitalized interest	$22	$24	$31

See Note 1 — Significant Accounting Policies for additional information regarding property, plant and equipment policies.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

9. Jointly Owned Electric Utility Plant

Our material undivided ownership interests in jointly owned electric plants at December 31, 2020 and 2019 were as follows:

	Nuclear Generation			
	Quad Cities	Peach Bottom	Salem	Nine Mile Point Unit 2
Operator	**Generation**	**Generation**	**PSEG Nuclear**	**Generation**
Ownership interest	75.00%	50.00%	42.59%	82.00%
Our share as of December 31, 2020				
Plant in service	$1,188	$1,506	$ 717	$ 990
Accumulated depreciation	670	601	265	187
Construction work in progress	13	13	39	25
Our share as of December 31, 2019				
Plant in service	$1,161	$1,466	$ 663	$ 951
Accumulated depreciation	627	571	249	156
Construction work in progress	13	21	53	27

Our undivided ownership interests are financed with our funds and all operations are accounted for as if such participating interests were wholly owned facilities. Our share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses in the Consolidated Statements of Operations and Comprehensive Income.

10. Asset Retirement Obligations

Nuclear Decommissioning Asset Retirement Obligations

We have a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate our decommissioning obligation related to our nuclear generating stations for financial accounting and reporting purposes, we use a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models, and discount rates. We update our ARO annually unless circumstances warrant more frequent updates, based on our review of updated cost studies and our annual evaluation of cost escalation factors and probabilities assigned to various scenarios. We began decommissioning the TMI nuclear plant upon permanently ceasing operations in 2019. See below section for decommissioning of Zion Station.

The financial statement impact for changes in the ARO, on an individual unit basis, due to the changes in and timing of estimated cash flows generally result in a corresponding change in the unit's ARC within Property, plant, and equipment in the Consolidated Balance Sheets. If the ARO decreases for a Non-Regulatory Agreement unit without any remaining ARC, the corresponding change is recorded as decrease in Operating and maintenance expense within the Consolidated Statements of Operations and Comprehensive Income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

The following table provides a rollforward of the nuclear decommissioning ARO reflected in the Consolidated Balance Sheets, from January 1, 2019 to December 31, 2020:

	Nuclear Decommission ARO
Balance at January 1, 2019	$10,005
Net increase due to changes in, and timing of, estimated future cash flows	864
Sale of Oyster Creek	(755)
Accretion expense	479
Costs incurred related to decommissioning plants	(89)
Balance at December 31, 2019[(a)]	10,504
Net increase due to changes in, and timing of, estimated future cash flows	1,022
Accretion Expense	489
Costs incurred related to decommissioning plants	(93)
Balance at December 31, 2020[(a)]	$11,922

(a) Includes $80 million and $112 million as the current portion of the ARO at December 31, 2020 and 2019, respectively, which is included in Other current liabilities in the Consolidated Balance Sheets.

The net $1,022 million increase in the ARO during 2020 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year. These adjustments primarily include:

- A net increase of approximately $800 million was driven by updates to Byron and Dresden reflecting changes in assumed retirement dates and assumed methods of decommissioning as a result of the announcement to early retire these plants in 2021. Refer to Note 7 — Early Plant Retirements for additional information.
- An increase of approximately $360 million resulting from the change in the assumed DOE spent fuel acceptance date for disposal from 2030 to 2035.
- A decrease of approximately $220 million due to lower estimated decommissioning costs primarily for Limerick and Peach Bottom nuclear units resulting from the completion of updated cost studies.

The 2020 ARO updates resulted in an increase of $60 million in Operating and maintenance expense for the year ended December 31, 2020 within the Consolidated Statements of Operations and Comprehensive Income.

The net $864 million increase in the ARO during 2019 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments primarily include:

- An increase of approximately $780 million for changes in the assumed retirement timing probabilities for sites including certain economically challenged nuclear plants and the extension of Peach Bottom's operating life.
- An increase of approximately $490 million for other impacts that included updated cost escalation rates, primarily for labor, equipment and materials, and current discount rates.
- Lower estimated costs to decommission TMI, Nine Mile Point, Ginna, Braidwood, Byron, and LaSalle nuclear units of approximately $410 million resulting from the completion of updated cost studies.

The 2019 ARO updates resulted in a decrease of $150 million in Operating and maintenance expense for the year ended December 31, 2019 within the Consolidated Statements of Operations and Comprehensive

Income. See Note 7 — Early Plant Retirements for additional information regarding TMI and economically challenged nuclear plants and Note 3 — Regulatory Matters regarding the Peach Bottom second license renewal.

NDT Funds

NDT funds have been established for each generation station unit to satisfy our nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with our nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to us and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO’s calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. On March 31, 2017, PECO filed its Nuclear Decommissioning Cost Adjustment with the PAPUC proposing an annual recovery from customers of approximately $4 million. This amount reflects a decrease from the previously approved annual collection of approximately $24 million primarily due to the removal of the collections for Limerick Units 1 and 2 as a result of the NRC approving the extension of the operating licenses for an additional 20 years. On August 8, 2017, the PAPUC approved the filing and the new rates became effective January 1, 2018.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by us, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both us and EDF. Through PECO, we have recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise we will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls would be borne by us. No recourse exists to collect additional amounts from utility customers for any of our other nuclear units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd’s or PECO’s customers, subject to certain limitations that allow sharing of excess funds with us related to the former PECO units. With respect to our other nuclear units, we retain any funds remaining after decommissioning. However, in connection with CENG’s acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to NDT funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. We expect to comply with applicable regulations and timely commence and complete all required decommissioning activities.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2020 and 2019, the NDT funds totaled $14,599 million and $13,353 million, respectively. The NDT funds include $134 million and $163 million for the current portion of the NDT at December 31, 2020 and 2019, respectively, which are included in Other current assets in the Consolidated Balance Sheets. See Note 22 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreements with the ICC and PAPUC that dictate our obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis and the former PECO units in total, decommissioning-related activities net of applicable taxes, including realized and unrealized gains and losses on the NDT funds, depreciation of the ARC and accretion of the decommissioning obligation are generally offset within the Consolidated Statements of Operations and Comprehensive Income and are recorded as related party balances on our Consolidated Balance Sheets. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

For the former PECO units, given the symmetric settlement provisions that allow for continued recovery of decommissioning costs from PECO customers in the event of a shortfall and the obligation for us to ultimately return any excess funds to PECO customers (on an aggregate basis for all seven units), decommissioning-related activities are generally offset within the Consolidated Statements of Operations and Comprehensive Income regardless of whether the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to noncurrent payables to or noncurrent receivables from affiliates. Any changes to the existing PECO regulatory agreements could impact our ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to our financial statements could be material.

For the former ComEd units, given no further recovery from ComEd customers is permitted and we retain an obligation to ultimately return any unused NDTs to ComEd customers (on a unit-by-unit basis), to the extent the related NDT investment balances are expected to exceed the total estimated decommissioning obligation for each unit, the offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in us recognizing a noncurrent payable to affiliates. However, given the asymmetric settlement provision that does not allow for continued recovery from ComEd customers in the event of a shortfall, recognition of a regulatory asset at ComEd is not permissible and accounting for decommissioning-related activities for that unit would not be offset, and the impact to the Consolidated Statements of Operations and Comprehensive Income could be material during such periods.

As of December 31, 2020, decommissioning-related activities for all of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are currently offset within the Consolidated Statements of Operations and Comprehensive Income.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in the Consolidated Statements of Operations and Comprehensive Income.

See Note 23 — Related Party Transactions for additional information regarding balances with affiliates.

Zion Station Decommissioning

In 2010, we completed an ASA under which ZionSolutions assumed responsibility for decommissioning Zion Station and we transferred to ZionSolutions substantially all the Zion Station's assets, including the related NDT funds.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to us, we will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility.

We had retained our obligation for the SNF as well as certain NDT assets to fund the obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by us. As of December 31, 2020, the ARO associated with Zion's SNF storage facility is $175 million and the NDT funds available to fund this obligation are $66 million.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded in the Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2020 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by us to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2020 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain LLRW); (3) the consideration of multiple scenarios where decommissioning and site restoration activities, as applicable, are completed under possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the consideration of multiple end of life scenarios; (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 4% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.6% to 6.1% (as compared to a historical 5-year annual average pre-tax return of approximately 9.0%).

We are required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing our ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, we may be required to take steps, such as providing financial guarantees through surety bonds, letters of credit, or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, the cash flows and financial positions may be significantly adversely affected.

(Dollars in millions, except per share data unless otherwise noted)

We filed our biennial decommissioning funding status report with the NRC on February 24, 2021 for all units, including our shutdown units, except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions, LLC. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2020 for all units except for Byron Units 1 and 2. We stated that it intends to submit its PSDAR with additional decommissioning cost information by July 1, 2021, for Byron Units 1 and 2, and will evaluate the status of funding assurance based on the updated cost information and provide additional funding assurance by the time of shutdown if required.

We will file the next decommissioning funding status report with the NRC by March 31, 2022. This report will reflect the status of decommissioning funding assurance as of December 31, 2021 for shutdown units.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of our units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations

We have AROs for plant closure costs associated with the fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. See Note 1 — Significant Accounting Policies for additional information on the accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected in the Consolidated Balance Sheets from January 1, 2019 to December 31, 2020:

	Non-nuclear AROs
Balance at January 1, 2019	$238
Net increase due to changes in, and timing of, estimated future cash flows	7
Development projects	2
Accretion expense	12
Asset divestitures	(42)
Payments	(1)
Balance at December 31, 2019	216
Net increase due to changes in, and timing of, estimated future cash flows	2
Development projects	1
Accretion expense	11
Asset divestitures	(4)
Payments	(4)
AROs reclassified to liabilities held for sale[a]	(10)
Balance at December 31, 2020	$212

(a) Represents AROs related to our solar business, which were classified as held for sale as a result of the sale agreement. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

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(Dollars in millions, except per share data unless otherwise noted)

11. Leases

Lessee

We have operating leases for which we are the lessee. The significant types of leases are contracted generation, real estate, and vehicles and equipment. The following table outlines other terms and conditions of the lease agreements as of December 31, 2020. We do not have material finance leases in 2020 or in 2019.

	Years
Remaining lease terms	1 – 35
Options to extend the term	2 – 30
Options to terminate within	1 – 4

The components of operating lease costs were as follows:

	For the years ended December 31,	
	2020	2019
Operating lease costs	$194	$222
Variable lease costs	234	282
Short-term lease costs	2	19
Total lease costs[(a)]	$430	$523

(a) Excludes $44 million of sublease income recorded for each of the years ended December 31, 2020 and 2019.

The rental expense under the prior lease accounting guidance for the year ended December 31, 2018 was $558 million. This was inclusive of the contingent operating lease payments associated with contracted generation agreements that are not included in the minimum future operating lease payments table. Payments made under the contracted generation lease agreements totaled to $493 million.

The following table provides additional information regarding the presentation of operating lease ROU assets and lease liabilities within the Consolidated Balance Sheets:

	As of December 31, 2020	As of December 31, 2019
Operating lease ROU assets[(a)]		
Other deferred debits and other assets	$726	$ 895
Operating lease liabilities[(a)]		
Other current liabilities	132	157
Other deferred credits and other liabilities	775	925
Total operating lease liabilities	$907	$1,082

(a) The operating ROU assets and lease liabilities include $528 million related to contracted generation as of December 31, 2020 and $664 million as of December 31, 2019.

The weighted average remaining lease terms, in years, and the weighted average discount rates for operating leases were as follows:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

	Weighted Average Remaining Lease Terms (in Years)	Weighted Average Discount Rates
As of December 31, 2020	10.5	4.9%
As of December 31, 2019	10.6	4.8%

Future minimum lease payments for operating leases as of December 31, 2020 were as follows:

Year	Future Minimum Lease payments
2021	$ 145
2022	113
2023	100
2024	98
2025	99
Remaining years	640
Total	1,195
Interest	288
Total operating lease liabilities	$ 907

Cash paid for amounts included in the measurement of operating lease liabilities was $204 million and $206 million for the year ended December 31, 2020 and 2019, respectively.

ROU assets obtained in exchange for operating lease obligations were $3 million and $14 million for the year ended December 31, 2020, and 2019, respectively.

Lessor

We have operating leases for which we are the lessor. The significant types of leases are contracted generation and real estate. The following table outlines other terms and conditions of the lease agreements as of December 31, 2020.

	Years
Remaining lease terms	1 – 31
Options to extend the term	1 – 5

The components of lease income were as follows:

	For the years ended December 31,	
	2020	2019
Operating lease income	$ 47	$ 47
Variable lease income	282	258

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Future minimum lease payments to be recovered under operating leases as of December 31, 2020 were as follows:

Year	Minimum lease payments to be recovered
2021	$ 45
2022	45
2023	45
2024	45
2025	45
Remaining years	182
Total	$407

12. Asset Impairments

We evaluate the carrying value of long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. We determine if long-lived assets or asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value analysis is primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could potentially result in material future impairments of our long-lived assets.

Antelope Valley Solar Facility

Antelope Valley, a 242 MW solar facility in Lancaster, CA, sells all of its output to PG&E through a PPA. As a result of the PG&E bankruptcy filing in the first quarter of 2019, we completed a comprehensive review of Antelope Valley's estimated undiscounted future cash flows and no impairment charge was recorded.

The United States Bankruptcy Court entered an order on June 20, 2020 confirming PG&E's plan of reorganization. On July 1, 2020 the plan became effective, and PG&E emerged from bankruptcy. Under the confirmed plan, PG&E will continue to honor the existing PPA agreement with Antelope Valley.

See Note 17 — Debt and Credit Agreements for additional information.

New England Asset Group

During the first quarter of 2018, Mystic Unit 9 did not clear in the ISO-NE capacity auction for the 2021 – 2022 planning year. On March 29, 2018, we notified grid operator ISO-NE of its plans to early retire its Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. These events suggested that the carrying value of the New England asset group may be impaired. In the first quarter of 2018, we completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and no impairment charge was required.

In the third quarter of 2020, in conjunction with the retirement announcement of Mystic Units 8 and 9, we completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the estimated undiscounted future cash flows and fair value of the New England asset group were less than their carrying values. As a result, a pre-tax impairment charge of $500 million was recorded in the third quarter of 2020 within Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income. See Note 7 — Early Plant Retirements for additional information.

(Dollars in millions, except per share data unless otherwise noted)

Midwest Asset Group

In the third quarter of 2020, in conjunction with the retirement announcements of the Byron and Dresden nuclear plants, we completed a comprehensive review of the estimated undiscounted future cash flows of the Midwest asset group and no impairment charge was required.

We will continue to monitor the recoverability of the carrying value of the Midwest asset group as certain other nuclear plants in Illinois are also showing increased signs of economic distress, which could lead to an early retirement. See Note 7 — Early Plant Retirements for additional information.

Equity Method Investments in Certain Distributed Energy Companies

In the third quarter of 2019, our equity method investments in certain distributed energy companies were fully impaired due to an other-than-temporary decline in market conditions and underperforming projects. We recorded a pre-tax impairment charge of $164 million in Equity in losses of unconsolidated affiliates and an offsetting pre-tax $96 million in Net income attributable to noncontrolling interests in the Consolidated Statements of Operations and Comprehensive Income. As a result, we accelerated the amortization of investment tax credits associated with these companies and recorded a benefit of $46 million in Income taxes. The impairment charge and the accelerated amortization of investment tax credits resulted in a net $15 million decrease to our earnings. See Note 21 — Variable Interest Entities for additional information.

13. Intangible Assets

Our intangible assets and liabilities, included in Unamortized energy contract assets and liabilities and Other deferred debits and other assets in the Consolidated Balance Sheets, consisted of the following as of December 31, 2020 and 2019. The intangible assets and liabilities shown below are amortized on a straight line basis, except for unamortized energy contracts which are amortized in relation to the expected realization of the underlying cash flows:

	December 31, 2020			December 31, 2019		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Unamortized Energy Contracts	$1,963	$(1,642)	$321	$1,967	$(1,612)	$355
Customer Relationships	326	(215)	111	343	(190)	153
Trade Name	222	(197)	25	243	(193)	50
Total	$2,511	$(2,054)	$457	$2,553	$(1,995)	$558

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2020, 2019, and 2018:

For the Years Ended December 31,	Amortization Expense[(a)]
2020	$81
2019	74
2018	63

(a) Amortization of unamortized energy contracts totaling $30 million, $21 million, and $14 million for the years ended December 31, 2020, 2019, and 2018, respectively, was recorded in Operating revenues or Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.

The following table summarizes the estimated future amortization expense related to intangible assets and liabilities as of December 31, 2020:

For the Years Ending December 31,	Estimated Future Amortization Expense
2021	$81
2022	57
2023	51
2024	48
2025	41

Renewable Energy Credits

Our RECs are included in Other current assets and Other deferred debits and other assets in the Consolidated Balance Sheets. Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Generally, revenue for RECs that are sold to a counterparty under a contract that specifically identifies a power plant is recognized at a point in time when the power is produced. This includes both bundled and unbundled REC sales. Otherwise, the revenue is recognized upon physical transfer of the REC to the customer.

The following table presents the current and non-current REC’s as of December 31, 2020 and 2019:

	As of December 31, 2020	As of December 31, 2019
Current REC’s	$621	$336
Noncurrent REC’s	—	86

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

14. Income Taxes

Components of Income Tax Expense or Benefit

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Years ended December 31,		
	2020	2019	2018
Included in operations:			
Federal			
Current	$130	$147	$ 337
Deferred	150	346	(347)
Investment tax credit amortization	(25)	(69)	(21)
State			
Current	40	10	6
Deferred	(46)	82	(83)
Total	$249	$516	$(108)

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. federal statutory rate principally due to the following:

	For the years ended December 31,		
	2020[(a)]	2019[(a)]	2018[(a)]
U.S. federal statutory rate	21.0%	21.0%	21.0%
Increase (decrease) due to:			
State income taxes, net of Federal income tax benefit	0.5	3.8	(16.6)
Qualified NDT fund income	23.5	12.3	(11.8)
Amortization of investment tax credit, including deferred taxes on basis difference	(2.6)	(3.0)	(6.5)
Production tax credits and other credits	(5.4)	(4.8)	(13.5)
Noncontrolling interests	3.2	(1.2)	(6.1)
Tax settlements	(10.3)	—	—
Tax Cuts and Jobs Act of 2017	—	—	2.7
Other	(0.1)	(1.2)	1.3
Effective income tax rate	29.8%	26.9%	(29.5)%

(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2020 and 2019 are presented below:

	As of December 31, 2020	As of December 31, 2019
Plant basis differences	$(2,592)	$(2,814)
Accrual based contracts	(37)	(43)
Derivatives and other financial instruments	(41)	88
Deferred pension and postretirement obligation	(236)	(220)
Nuclear decommissioning activities	(742)	(503)
Deferred debt refinancing costs	16	20
Tax loss carryforward	55	55
Tax credit carryforward	838	897
Investment in partnerships	(813)	(808)
Other, net	347	236
Deferred income tax liabilities (net)	$(3,205)	$(3,092)
Unamortized investment tax credits[a]	(445)	(648)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(3,650)	$(3,740)

(a) Does not include unamortized investment tax credits reclassified to liabilities held for sale as of December 31, 2020.

The following table provides our carryforwards, which are presented on a post-apportioned basis, and any corresponding valuation allowances as of December 31, 2020.

Federal	
Federal general business credits carryforwards and other carryforwards	$ 852
State	
State net operating losses and other carryforwards	1,118
Deferred taxes on state tax attributes (net)	76
Valuation allowance on state tax attributes	23
Year in which net operating loss or credit carryforwards will begin to expire[a]	2034

(a) State net operating loss carryforwards will begin expiring in 2029.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

Tabular Reconciliation of Unrecognized Tax Benefits

The following table presents changes in unrecognized tax benefits.

	Unrecognized tax benefits
Balance at January 1, 2018	$ 468
Change to positions that only affect timing	15
Increases based on tax positions prior to 2018	21
Decreases based on tax positions prior to 2018[a]	(36)
Decrease from settlements with taxing authorities	(53)
Decreases from expiration of statute of limitations	(7)
Balance at December 31, 2018	408
Change to positions that only affect timing	12
Increases based on tax positions related to 2019	1
Increases based on tax positions prior to 2019	19
Decreases based on tax positions prior to 2019	(3)
Decrease from settlements with taxing authorities	4
Balance at December 31, 2019	441
Increases based on tax positions related to 2020	1
Increases based on tax positions prior to 2020	23
Decreases based on tax positions prior to 2020[b]	(346)
Decrease from settlements with taxing authorities[b]	(69)
Balance at December 31, 2020	$ 50

(a) We decreased our unrecognized state tax benefits primarily due to the receipt of favorable guidance with respect to the deductibility of certain depreciable fixed assets.

(b) Our unrecognized federal and state tax benefits decreased in the first quarter of 2020 by approximately $411 million due to the settlement of a federal refund claim with IRS Appeals. The recognition of these tax benefits resulted in an increase in net income of $73 million in the first quarter of 2020, reflecting a decrease to income tax expense of $67 million.

Recognition of unrecognized tax benefits

The following table presents the unrecognized tax benefits that, if recognized, would decrease the effective tax rate.

December 31, 2020	$ 39
December 31, 2019	429
December 31, 2018	408

Total amounts of interest and penalties recognized

We did not record material interest and penalty expense related to tax positions reflected in the Consolidated Balance Sheets. Interest expense and penalty expense are recorded in Interest expense, net and Other, net, respectively, in Other income and deductions in the Consolidated Statements of Operations and Comprehensive Income.

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Description of tax years open to assessment by major jurisdiction

Major Jurisdiction	Open Years
Federal consolidated income tax returns	2010 – 2019
Illinois unitary corporate income tax returns	2012 – 2019
New Jersey separate corporate income tax returns	2013 – 2019
New York combined corporate income tax returns	2010 – March 2012
New York combined corporate income tax returns	2011 – 2019
Pennsylvania separate corporate income tax returns	2011 – 2019

Other Tax Matters

Long-Term Marginal State Income Tax Rate

Quarterly, we review and update the marginal state income tax rates for changes in state apportionment. We remeasure our existing deferred income tax balances to reflect the changes in marginal rates, which results in either an increase or a decrease to their net deferred income tax liability balances.

	December 31, 2020	December 31, 2019	December 31, 2018
(Decrease) increase to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$(26)	$9	$(53)

Allocation of Tax Benefits

We are a party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net federal and state benefits attributable to Exelon is reallocated to the parties. That allocation is treated as a contribution to the capital of the party receiving the benefit.

The following table presents the allocation of tax benefits from Exelon to us under the Tax Sharing Agreement.

December 31, 2020	$ 64
December 31, 2019	41
December 31, 2018	155

Research and Development Activities

In the fourth quarter of 2019, we recognized additional tax benefits related to certain research and development activities that qualify for federal and state tax incentives for the 2010 through 2018 tax years, which resulted in an increase in net income of $75 million for the year ended December 31, 2019, reflecting a decrease in Income tax expense of $66 million.

15. Retirement Benefits

Exelon sponsors defined benefit pension plans and OPEB plans for essentially all our current employees. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018, most newly-hired non-represented, non-craft, employees are not eligible for pension benefits, and will instead be eligible to

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receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented, non-craft, employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits. Effective January 1, 2021, most non-represented, non-craft, employees who are under the age of 40 are not eligible for retiree health care benefits.

The table below shows the pension and OPEB plans in which our employees participated at December 31, 2020:

Name of Plan
Qualified Pension Plans:
Exelon Corporation Retirement Program[a]
Exelon Corporation Pension Plan for Bargaining Unit Employees[a]
Exelon New England Union Employees Pension Plan[a]
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek[a]
Pension Plan of Constellation Energy Group, Inc.[b]
Pension Plan of Constellation Energy Nuclear Group, LLC[c]
Nine Mile Point Pension Plan[c]
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B[b]
Pepco Holdings LLC Retirement Plan[d]
Non-Qualified Pension Plans:
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan[a]
Exelon Corporation Supplemental Management Retirement Plan[a]
Constellation Energy Group, Inc. Senior Executive Supplemental Plan[b]
Constellation Energy Group, Inc. Supplemental Pension Plan[b]
Constellation Energy Group, Inc. Benefits Restoration Plan[b]
Constellation Energy Nuclear Plan, LLC Executive Retirement Plan[c]
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan[c]
Baltimore Gas & Electric Company Executive Benefit Plan[b]
Baltimore Gas & Electric Company Manager Benefit Plan[b]
Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan[d]
Conectiv Supplemental Executive Retirement Plan[d]
OPEB Plans:
PECO Energy Company Retiree Medical Plan[a]
Exelon Corporation Health Care Program[a]
Exelon Corporation Employees’ Life Insurance Plan[a]
Exelon Corporation Health Reimbursement Arrangement Plan[a]
Constellation Energy Group, Inc. Retiree Medical Plan[b]
Constellation Energy Group, Inc. Retiree Dental Plan[b]
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan[b]
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan[b]
Exelon New England Union Post-Employment Medical Savings Account Plan[a]
Retiree Medical Plan of Constellation Energy Nuclear Group, LLC[c]
Retiree Dental Plan of Constellation Energy Nuclear Group, LLC[c]

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Name of Plan
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees[(c)]
Pepco Holdings LLC Welfare Plan for Retirees[(d)]

(a) These plans are collectively referred to as the legacy Exelon plans.

(b) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.

(c) These plans are collectively referred to as the legacy CENG plans.

(d) These plans are collectively referred to as the legacy PHI plans.

Costs Allocation from Exelon

We account for our participation in Exelon's pension and OPEB plans by applying multi-employer accounting. Exelon allocates costs related to its pension and OPEB plans to its subsidiaries based on both active and retired employee participation in each plan.

We were allocated pension and OPEB costs of $115 million, $135 million, and $204 million for the years ended December 31, 2020, 2019, and 2018, respectively. We include the service cost and non-service cost components in Operating and maintenance expense and Property, plant, and equipment, net in the consolidated financial statements.

Contributions

Exelon allocates contributions related to its legacy Exelon pension and OPEB plans to its subsidiaries based on accounting cost. For legacy CEG, CENG, FitzPatrick, and PHI plans, pension and OPEB contributions are allocated to the subsidiaries based on employee participation (both active and retired). The following table provide our contributions to the pension and OPEB plans:

Pension Benefits			OPEB		
2020	2019	2018	2020	2019	2018
$236	$160	$128	$19	$15	11

Exelon considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation, and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy to make levelized annual contributions with the objective of achieving 100% funded status on an ABO basis over time. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its OPEB plans, including liabilities management, levels of benefit claims paid, and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). The amounts below include our benefit payments related to unfunded plans.

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The following table provides our planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to OPEB plans in 2021:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Planned contributions	$196	$27	$24

Defined Contribution Savings Plan

We participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. We match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2020, 2019 and 2018:

For the Years Ended December 31,	
2020	$63
2019	73
2018	86

16. Derivative Financial Instruments

We use derivative instruments to manage commodity price risk, interest rate risk, and foreign exchange risk related to ongoing business operations.

Authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include NPNS, cash flow hedges, and fair value hedges. All derivative economic hedges related to commodities, referred to as economic hedges, are recorded at fair value through earnings. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivative settles and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below, which present fair value balances, the energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

Our use of cash collateral is generally unrestricted unless we are downgraded below investment grade.

Commodity Price Risk

We employ established policies and procedures to manage our risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and commodity

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products. We believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

To the extent the amount of energy we produce differs from the amount of energy we have contracted to sell, we are exposed to market fluctuations in the prices of electricity, fossil fuels, and other commodities. We use a variety of derivative and non-derivative instruments to manage the commodity price risk of our electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. We are also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

Additionally, we are exposed to certain market risks through our proprietary trading activities. The proprietary trading activities are a complement to our energy marketing portfolio but represent a small portion of our overall energy marketing activities and are subject to limits established by the RMC.

The following table provides a summary of the derivative fair value balances recorded as of December 31, 2020 and 2019:

	Economic Hedges	Proprietary Trading	Collateral[(a)(b)]	Netting[(a)]	Subtotal
December 31, 2020					
Mark-to-market derivative assets (current assets)	$ 2,757	$ 40	$103	$(2,261)	$ 639
Mark-to-market derivative assets (noncurrent assets)	1,501	4	64	(1,015)	554
Total mark-to-market derivative assets	4,258	44	167	(3,276)	1,193
Mark-to-market derivative liabilities (current liabilities)	(2,629)	(23)	131	2,261	(260)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,335)	(2)	118	1,015	(204)
Total mark-to-market derivative liabilities	(3,964)	(25)	249	3,276	(464)
Total mark-to-market derivative net assets (liabilities)	$ 294	$ 19	$416	$ —	$ 729
December 31, 2019					
Mark-to-market derivative assets (current assets)	$ 3,506	$ 72	$287	$(3,190)	$ 675
Mark-to-market derivative assets (noncurrent assets)	1,238	25	122	(877)	508
Total mark-to-market derivative assets	4,744	97	409	(4,067)	1,183
Mark-to-market derivative liabilities (current liabilities)	(3,713)	(38)	357	3,190	(204)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,140)	(11)	163	877	(111)
Total mark-to-market derivative liabilities	(4,853)	(49)	520	4,067	(315)
Total mark-to-market derivative net assets (liabilities)	$ (109)	$ 48	$929	$ —	$ 868

(a) We net all available amounts allowed under the derivative authoritative guidance in the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases we may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables,

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transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These amounts are not material and not reflected in the table above.

(b) Of the collateral posted, $209 million and $511 million represents variation margin on the exchanges at December 31, 2020 and 2019, respectively.

Economic Hedges (Commodity Price Risk)

For the years ended December 31, 2020, 2019, and 2018, we recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

	Gain (Loss)		
Income Statement Location	**2020**	**2019**	**2018**
Operating revenues	$112	$ —	$(270)
Purchased power and fuel	168	(204)	(47)
Total	$280	$(204)	$(317)

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on owned and contracted generation positions that have not been hedged. We hedge commodity price risk on a ratable basis over three-year periods. As of December 31, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94% – 97% for 2021.

Proprietary Trading (Commodity Price Risk)

We also execute commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Gains and losses associated with proprietary trading are reported as Operating revenues in the Consolidated Statements of Operations and Comprehensive Income and are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows. For the years ended December 31, 2020, 2019, and 2018, net pre-tax commodity mark-to-market gains and losses were not material.

Interest Rate and Foreign Exchange Risk

We utilize interest rate swaps, which are treated as economic hedges, to manage our interest rate exposure. On July 1, 2018, we de-designated our cash flow hedges related to interest rate risk. The notional amounts were $516 million and $569 million at December 31, 2020 and 2019, respectively.

We utilize foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, which are treated as economic hedges. The notional amounts were $149 million and $231 million at December 31, 2020 and 2019, respectively.

The mark-to-market derivative assets and liabilities as of December 31, 2020 and 2019 and the mark-to-market gains and losses for the years ended December 31, 2020, 2019, and 2018 were not material.

Credit Risk

We would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date.

For commodity derivatives, we enter into enabling agreements that allow for payment netting with our counterparties, which reduces our exposure to counterparty risk by providing for the offset of amounts

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payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, our credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with us as specified in each enabling agreement. Our credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on the credit exposure for all derivative instruments, NPNS and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2020. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

Rating as of December 31, 2020	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$577	$27	$550	—	$ —
Non-investment grade	32	—	32		
No external ratings					
Internally rated – investment grade	165	1	164		
Internally rated – non-investment grade	80	28	52		
Total	$854	$56	$798	—	$ —

Net Credit Exposure by Type of Counterparty	As of December 31, 2020
Financial institutions	$ 15
Investor-owned utilities, marketers, power producers	607
Energy cooperatives and municipalities	138
Other	38
Total	$798

(a) As of December 31, 2020, credit collateral held from counterparties where we had credit exposure included $31 million of cash and $25 million of letters of credit. The credit collateral does not include non-liquid collateral.

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of our derivative instruments contain provisions that require us to post collateral. We also enter into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and

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margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon our credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk related contingent features stipulate that if we were to be downgraded or lose our investment grade credit rating (based on our senior unsecured debt rating), we would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, we believe an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

	As of December 31,	
Credit-Risk Related Contingent Features	**2020**	**2019**
Gross fair value of derivative contracts containing this feature[a]	$(834)	$(956)
Offsetting fair value of in-the-money contracts under master netting arrangements[b]	537	649
Net fair value of derivative contracts containing this feature[c]	$(297)	$(307)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which we could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

As of December 31, 2020 and 2019, we posted or held the following amounts of cash collateral and letters of credit on derivative contracts with external counterparties, after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

	As of December 31,	
	2020	**2019**
Cash collateral posted	$ 511	$ 982
Letters of credit posted	226	264
Cash collateral held	110	103
Letters of credit held	40	112
Additional collateral required in the event of a credit downgrade below investment grade	1,432	1,509

We entered into supply forward contracts with certain utilities with one-sided collateral postings only from us. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including us, are required to post collateral once certain unsecured credit limits are exceeded.

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17. Debt and Credit Agreements

Short-Term Borrowings

We meet our short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. We may use our credit facility for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects our commercial paper program supported by the revolving credit agreements and bilateral credit agreements at December 31, 2020 and 2019:

Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings at December 31,	
2020[(a)(b)]	2019[(a)(b)]	2020	2019	2020	2019
$5,300	$5,300	$340	$320	0.27%	1.84%

(a) Excludes $1,500 million and $1,400 million in bilateral credit facilities at December 31, 2020 and 2019, respectively, and $144 million and $159 million in credit facilities for project finance at December 31, 2020 and 2019, respectively. These credit facilities do not back our commercial paper program.

(b) At December 31, 2020, excludes $38 million of a credit facility agreement arranged at minority and community banks. This facility expires on October 8, 2021 and is solely utilized to issue letters of credit. At December 31, 2019, excludes $44 million of a credit facility agreement arranged at minority and community banks.

In order to maintain our commercial paper program in the amounts indicated above, we must have a credit facility in place, at least equal to the amount of our commercial paper program. We do not issue commercial paper in an aggregate amount exceeding the then available capacity under our credit facility.

At December 31, 2020, we had the following aggregate bank commitments, credit facility borrowings and available capacity under our respective credit facilities:

				Available Capacity at December 31, 2020	
Facility Type	Aggregate Bank Commitment[(b)]	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper
Syndicated Revolver[(a)]	$5,300	$ —	$262	$5,038	$4,698
Bilaterals	1,500	—	840	660	—
Project Finance	144	—	119	25	—

(a) On May 26, 2018, our syndicated revolving credit facility had the maturity date extended to May 26, 2023.

(b) Excludes $38 million of credit facility agreements arranged at minority and community banks. These facilities expire on October 8, 2021 and are solely utilized to issue letters of credit. As of December 31, 2020, letters of credit issued under these facilities totaled $5 million.

On March 19, 2020, we borrowed $1.5 billion on our revolving credit facility due to disruptions in the commercial paper markets as a result of COVID-19. The funds were used to refinance commercial paper. We repaid the $1.5 billion borrowed on the revolving credit facility on April 3, 2020.

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Short-Term Loan Agreements

On March 19, 2020, we entered into a term loan agreement for $200 million. The loan agreement has an expiration of March 18, 2021. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.50% and all indebtedness thereunder is unsecured. The loan agreement is reflected in the Consolidated Balance Sheet within Short-term borrowings.

On March 31, 2020, we entered into a term loan agreement for $300 million. The loan agreement has an expiration of March 30, 2021. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.75% and all indebtedness thereunder is unsecured. The loan agreement is reflected in the Consolidated Balance Sheet within Short-term borrowings.

Bilateral Credit Agreements

The following table reflects the bilateral credit agreements at December 31, 2020:

Date Initiated		Latest Amendment Date	Maturity Date[a]	Amount
October 26, 2012	(b)	October 23, 2020	October 22, 2021	$200
January 11, 2013	(c)	January 4, 2019	March 1, 2021	100
January 5, 2016	(c)	January 4, 2019	April 5, 2021	150
February 21, 2019	(c)	N/A	March 31, 2021	100
October 25, 2019	(c)	N/A	N/A	200
October 25, 2019	(c)	N/A	N/A	100
November 20, 2019	(c)	N/A	N/A	300
November 21, 2019	(c)	N/A	N/A	150
November 21, 2019	(c)	N/A	November 21, 2021	100
May 15, 2020	(c)	N/A	N/A	100

(a) Credit facilities that do not contain a maturity date are specific to the agreements set within each contract. In some instances, credit facilities are automatically renewed based on the contingency standards set within the specific agreement.

(b) Bilateral credit facility relates to CENG and supports the issuance of letters of credit and funding for working capital and does not back our commercial paper program. During the second and third quarters of 2020, CENG drew on its bilateral credit facility. As of December 31, 2020, there was no outstanding balance at this facility.

(c) Bilateral credit agreements solely support the issuance of letters of credit and do not back our commercial paper program.

Borrowings under our revolving credit agreement bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon our credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are 27.5 and 127.5, respectively.

If we lose our investment grade rating, the maximum adders for prime rate borrowings and LIBOR-based rate borrowings would be 65 basis points and 165 basis points, respectively. The credit agreement also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

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Long-Term Debt

The following table present the outstanding long-term debt as of December 31, 2020 and 2019:

	Rates	Maturity Date	December 31, 2020	December 31, 2019
Long-term debt				
Senior unsecured notes	3.25 % – 7.60 %	2022 – 2042	$4,219	$ 5,420
Pollution control notes	2.50 % – 2.70 %	2020	—	412
Nuclear fuel procurement contracts	3.15 %	2020	—	3
Notes payable and other	2.10 % – 4.85 %	2021 – 2028	111	115
Nonrecourse debt:				
Fixed rates	2.29 % – 6.00 %	2031 – 2037	977	1,182
Variable rates	2.99 % – 3.18 %	2021 – 2027	765	811
Total long-term debt			6,072	7,943
Unamortized debt discount and premium, net			(5)	(5)
Unamortized debt issuance costs			(46)	(42)
Fair value adjustment			66	78
Long-term debt due within one year			(197)	(3,182)
Long-term debt			$5,890	$ 4,792

Long-term debt maturities in the periods 2021 through 2025 and thereafter are as follows:

2021	$ 197
2022	1,025
2023	1
2024	1
2025	900
Thereafter	3,948
Total	$6,072

Debt Covenants

As of December 31, 2020, we are in compliance with debt covenants.

Nonrecourse Debt

We have issued nonrecourse debt financing, in which approximately $2.2 billion of generating assets have been pledged as collateral at December 31, 2020. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against us in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, 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.

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Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in 2014. The loan will mature on January 5, 2037. Interest rates on the loan were fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. The advances were completed as of December 31, 2015 and the outstanding loan balance will bear interest at an average blended interest rate of 2.82%. As of December 31, 2020 and 2019, approximately $460 million and $485 million were outstanding, respectively. In addition, we have issued letters of credit to support the equity investment in the project. As of December 31, 2020, we had $37 million in letters of credit outstanding related to the project. In December 2017, our interests in Antelope Valley were contributed to and are pledged as collateral for the EGR IV financing structures referenced below.

Antelope Valley sells all of its output to PG&E through a PPA. On January 29, 2019, PG&E filed for protection under Chapter 11 of the U.S. Bankruptcy Code, which created an event of default for Antelope Valley's nonrecourse debt that provided the lender with a right to accelerate amounts outstanding under the loan such that they would become immediately due and payable. As a result of the event of default and in the absence of a waiver from the lender foregoing their acceleration rights, the debt was reclassified as current in the Consolidated Balance Sheet in the first quarter of 2019. Further, distributions from Antelope Valley to EGR IV were suspended.

The United States Bankruptcy Court entered an order on June 20, 2020 confirming PG&E's plan of reorganization. On July 1, 2020 the plan became effective, and PG&E emerged from bankruptcy. On July 21, 2020, Antelope Valley received a waiver from the DOE for the event of default and, as such, distributions from Antelope Valley to EGR IV were permitted and the debt was classified as noncurrent as of June 30, 2020. The debt continues to be presented as noncurrent as of December 31, 2020.

See Note 12 — Asset Impairments for additional information.

Continental Wind, LLC. In September 2013, Continental Wind, our indirect subsidiary, completed the issuance and sale of $613 million senior secured notes. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667 MW. The net proceeds were distributed to us for general business purposes. The notes are scheduled to mature on February 28, 2033. The notes bear interest at a fixed rate of 6.00% with interest payable semi-annually. As of December 31, 2020 and December 31, 2019, approximately $415 million and $447 million were outstanding, respectively.

In addition, Continental Wind has a $122 million letter of credit facility and $4 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2020, the Continental Wind letter of credit facility had $114 million in letters of credit outstanding related to the project.

In 2017, our interests in Continental Wind were contributed to EGRP. Refer to Note 21 — Variable Interest Entities for additional information on EGRP.

Renewable Power Generation. In March 2016, RPG, our indirect subsidiary, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to us for paydown of long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general business purposes. The loan is scheduled to mature on March 31, 2035. The term loan bears interest at a fixed rate of 4.11% payable semi-annually. As of December 31, 2020 and December 31, 2019, approximately $95 million and $106 million were outstanding, respectively.

In 2017, our interests in RPG were contributed to EGRP. Refer to Note 21 — Variable Interest Entities for additional information on EGRP.

SolGen, LLC. In September 2016, SolGen, LLC (SolGen), our indirect subsidiary, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to us

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for general business purposes. The loan is scheduled to mature on September 30, 2036. The term loan bears interest at a fixed rate of 3.93% payable semi-annually. As of December 31, 2020 and December 31, 2019, approximately $125 million and $131 million were outstanding, respectively. As a result of the sale agreement with an affiliate of Brookfield Renewable in the fourth quarter of 2020, the outstanding balance was reclassified to Liabilities held for sale in the Consolidated Balance Sheet as of December 31, 2020. In 2017, our interests in SolGen were contributed to and were pledged as collateral for the EGR IV financing structure. In December 2020, as part of the EGR IV financing, SolGen was removed from the collateral terms structured within the agreement. See EGR IV discussed below for additional information and Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the sale agreement.

ExGen Renewables IV. In November 2017, EGR IV, our indirect subsidiary, entered into an $850 million nonrecourse senior secured term loan credit facility agreement with a maturity date of November 28, 2024. In addition to the financing, EGR IV entered into interest rate swaps with an initial notional amount of $636 million at an interest rate of 2.32% to manage a portion of the interest rate exposure in connection with the financing.

In December 2020, EGR IV entered into a financing agreement for a $750 million nonrecourse senior secured term loan credit facility, scheduled to mature on December 15, 2027. The term loan bears interest at a variable rate equal to LIBOR plus 2.75%, subject to a 1% LIBOR floor with interest payable quarterly. In addition to the financing, EGR IV entered into interest rate swaps with an initial notional amount of $516 million at an interest rate of 1.05% to manage a portion of the interest rate exposure in connection with the financing.

The proceeds were used to repay the November 2017 nonrecourse senior secured term loan credit facility of $850 million, of which $709 million was outstanding as of the retirement date in December of 2020, and to settle the November 2017 interest rate swap. Our interests in EGRP and Antelope Valley remained contributed to and are pledged as collateral for this financing. As of December 31, 2020, $750 million was outstanding. See Note 21 — Variable Interest Entities for additional information on EGRP and Note 16 — Derivative Financial Instruments for additional information on interest rate swaps.

18. Fair Value of Financial Assets and Liabilities

We measure and classify fair value measurements in accordance with the hierarchy as defined by GAAP. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the short-term liabilities, long-term debt, and SNF obligation as of December 31, 2020 and 2019. We have no financial liabilities classified as Level 1.

The carrying amounts of the short-term liabilities as presented on the Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

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	December 31, 2020				December 31, 2019			
		Fair Value				Fair Value		
	Carrying Amount	Level 2	Level 3	Total	Carrying Amount	Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year[(a)]	$6,087	$5,648	$1,208	$6,856	$7,974	$7,304	$1,366	$8,670
SNF Obligation	1,208	909	—	909	1,199	1,055	—	1,055

(a) Includes unamortized debt issuance costs which are not fair valued. Refer to Note 17 — Debt and Credit Agreements for additional information on unamortized debt issuance costs.

We use the following methods and assumptions to estimate fair value of financial liabilities recorded at carrying cost:

Type	Level	Valuation
Long-term Debt, including amounts due within one year		
Taxable Debt Securities	2	The fair value is determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. We obtain credit spreads based on trades of existing our debt securities as well as other issuers in the utility sector with similar credit ratings. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.
Variable Rate Financing Debt	2	Debt rates are reset on a regular basis and the carrying value approximates fair value.
Government Backed Fixed Rate Project Financing Debt	3	The fair value is similar to the process for taxable debt securities. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable U.S. Treasury rate as well as a current market curve derived from government-backed securities.
Non-Government Backed Fixed Rate Nonrecourse Debt	3	Fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project.
SNF Obligation		
SNF Obligation	2	The carrying amount is derived from a contract with the DOE to provide for disposal of SNF from our nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week U.S. Treasury rate. The compounded obligation amount is discounted back to present value using our discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2035 and 2030 for the years ended December 31, 2020 and 2019, respectively.

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Recurring Fair Value Measurements

The following table presents assets and liabilities measured and recorded at fair value in the Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2020 and 2019:

	As of December 31, 2020					As of December 31, 2019				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents[(a)]	$ 124	$ —	$ —	$ —	$ 124	$ 214	$ —	$ —	$ —	$ 214
NDT fund investments										
Cash equivalents[(b)]	210	95	—	—	305	365	87	—	—	452
Equities	3,886	2,077	—	1,562	7,525	3,353	1,801	—	1,388	6,542
Fixed income										
Corporate debt[(c)]	—	1,485	285	—	1,770	—	1,421	257	—	1,678
U.S. Treasury and agencies	1,871	126	—	—	1,997	1,808	131	—	—	1,939
Foreign governments	—	56	—	—	56	—	42	—	—	42
State and municipal debt	—	101	—	—	101	—	90	—	—	90
Other	—	41	—	961	1,002	—	33	—	953	986
Fixed income subtotal	1,871	1,809	285	961	4,926	1,808	1,717	257	953	4,735
Private credit	—	—	212	629	841	—	—	254	508	762
Private equity	—	—	—	504	504	—	—	—	402	402
Real estate	—	—	—	679	679	—	—	—	607	607
NDT fund investments subtotal[(d)(e)]	5,967	3,981	497	4,335	14,780	5,526	3,605	511	3,858	13,500
Rabbi trust investments										
Cash equivalents	4	—	—	—	4	4	—	—	—	4
Mutual funds	29	—	—	—	29	25	—	—	—	25
Life insurance contracts	—	28	—	—	28	—	25	—	—	25
Rabbi trust investments subtotal	33	28	—	—	61	29	25	—	—	54
Investments in equities[(f)]	195	—	—	—	195	—	—	—	—	—
Commodity derivative assets										
Economic hedges	745	1,914	1,599	—	4,258	768	2,491	1,485	—	4,744
Proprietary trading	—	17	27	—	44	—	37	60	—	97
Effect of netting and allocation of collateral[(g)(h)]	(607)	(1,597)	(905)	—	(3,109)	(908)	(2,162)	(588)	—	(3,658)
Commodity derivative assets subtotal	138	334	721	—	1,193	(140)	366	957	—	1,183

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	As of December 31, 2020					As of December 31, 2019				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
DPP consideration	—	639	—	—	639	—	—	—	—	—
Total assets	$6,457	$ 4,982	$ 1,218	$4,335	$16,992	$ 5,629	$ 3,996	$1,468	$3,858	$14,951
Liabilities										
Commodity derivative liabilities										
Economic hedges	(682)	(1,928)	(1,354)	—	(3,964)	(1,071)	(2,855)	(927)	—	(4,853)
Proprietary trading	—	(21)	(4)	—	(25)	—	(34)	(15)	—	(49)
Effect of netting and allocation of collateral[g][h]	540	1,918	1,067	—	3,525	1,071	2,714	802	—	4,587
Commodity derivative liabilities subtotal	(142)	(31)	(291)	—	(464)	—	(175)	(140)	—	(315)
Deferred compensation obligation	—	(42)	—	—	(42)	—	(41)	—	—	(41)
Total liabilities	(142)	(73)	(291)	—	(506)	—	(216)	(140)	—	(356)
Total net assets	$6,315	$ 4,909	$ 927	$4,335	$16,486	$ 5,629	$ 3,780	$1,328	$3,858	$14,595

(a) We exclude cash of $171 million and $177 million at December 31, 2020 and 2019, respectively, and restricted cash of $20 million and $58 million at December 31, 2020 and 2019, respectively.

(b) Includes $116 million and $90 million of cash received from outstanding repurchase agreements at December 31, 2020 and 2019, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (e) below.

(c) Includes investments in equities sold short of $(62) million and $(48) million as of December 31, 2020 and 2019, respectively, held in an investment vehicle primarily to hedge the equity option component of convertible debt.

(d) Includes derivative assets of $2 million and $2 million, which have total notional amounts of $1,043 million and $724 million at December 31, 2020 and 2019, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of our exposure to credit or market loss.

(e) Excludes net liabilities of $181 million and $147 million at December 31, 2020 and 2019, respectively, which include certain derivative assets that have notional amounts of $104 million and $99 million at December 31, 2020 and 2019, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(f) Reflects equity investments held by us which were previously designated as equity investments without readily determinable fair values but are now publicly traded and therefore have readily determinable fair values. We recorded the fair value of these investments in Other current assets on the Consolidated Balance Sheets based on the quoted market prices of the stocks at December 31, 2020, which resulted in an unrealized gain of $186 million within Other, net in the Consolidated Statement of Operations and Comprehensive Income for the year ended December 31, 2020.

(g) Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $(67) million, $321 million, and $162 million allocated to Level 1, Level 2, and Level 3 mark-to-market

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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derivatives, respectively, as of December 31, 2020. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $163 million, $551 million, and $214 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2019.

(h) Of the collateral posted/(received), $209 million and $511 million represents variation margin on the exchanges as of December 31, 2020 and 2019, respectively.

As of December 31, 2020, we have outstanding commitments to invest in private credit, private equity, and real estate investments of approximately $195 million, $254 million, and $369 million, respectively. These commitments will be funded by our existing NDT funds.

We hold investments without readily determinable fair values with carrying amounts of $55 million and $69 million as of December 31, 2020 and December 31, 2019, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the years ended December 31, 2020 and December 31, 2019.

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2020 and 2019:

	For the year ended December 31, 2020		
	NDT Fund Investments	Mark-to-Market Derivatives	Total
Balance as of January 1, 2020	$511	$ 817	$1,328
Total realized / unrealized gains (losses)			
Included in net income	2	(414)[(a)]	(412)
Included in noncurrent payables to affiliates	21	—	21
Change in collateral	—	(53)	(53)
Purchases, sales, issuances and settlements			
Purchases	8	143	151
Sales	—	(27)	(27)
Settlements	(45)	—	(45)
Transfers into Level 3	—	(12)[(b)]	(12)
Transfers out of Level 3	—	(24)[(b)]	(24)
Balance as of December 31, 2020	$497	$ 430	$ 927
The amount of total gains included in net income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2020	$ 2	$ 6	$ 8

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	For the year ended December 31, 2019		
	NDT Fund Investments	Mark-to-Market Derivatives	Total
Balance as of January 1, 2019	$543	$575	$1,118
Total realized / unrealized gains (losses)			
Included in net income	5	(31)[(a)]	(26)
Included in noncurrent payables to affiliates	34	—	34
Change in collateral	—	138	138
Purchases, sales, issuances and settlements			
Purchases	44	132	176
Sales	(21)	(2)	(23)
Settlements	(94)	5	(89)
Transfers into Level 3	—	5[(b)]	5
Transfers out of Level 3	—	(5)[(b)]	(5)
Balance as of December 31, 2019	$511	$817	$1,328
The amount of total gains included in net income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2019	$ 5	$351	$ 356

(a) Includes a reduction for the reclassification of $420 million and $377 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2020 and 2019, respectively.

(b) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable, respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

The following table presents the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2020 and 2019:

	Operating Revenues	Purchased Power and Fuel	Other, net
Total (losses) gains included in net income for the year ended December 31, 2020	$(404)	$ (10)	$2
Change in unrealized (losses) gains relating to assets and liabilities held for the year ended December 31, 2020	(31)	37	2
Total gains (losses) included in net income for the year ended December 31, 2019	$ 219	$(245)	$5
Change in unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2019	546	(195)	5

Valuation Techniques Used to Determine Fair Value

Cash Equivalents. Investments with original maturities of three months or less when purchased, including mutual and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

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NDT Fund Investments. The trust fund investments have been established to satisfy our and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in equities and fixed income. Our and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments, including private credit, private equity, and real estate. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

Equities. These investments consist of individually held equity securities, equity mutual funds, and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which we are able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights, and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. The equity securities that are held directly by the trust funds are valued based on quoted prices in active markets and categorized as Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies, and fund investments are held in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly or more frequently, with 30 or less days of notice and without further restrictions.

Fixed income. For fixed income securities, which consist primarily of corporate debt securities, U.S. government securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds, and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class, or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. We have obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, we selectively corroborate the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Other fixed income investments primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold fund investments in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly or more frequently, with 30 or less days of notice and without further restrictions.

Derivative instruments. These instruments, consisting primarily of futures and swaps to manage risk, are recorded at fair value. Over-the-counter derivatives are valued daily, based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over-the-counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Private credit. Private credit investments primarily consist of investments in private debt strategies. These investments are generally less liquid assets with an underlying term of 3 to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Private credit investments held directly by us are categorized as Level 3 because they are based largely on inputs that are unobservable and utilize complex valuation models. For managed private credit funds, the fair value is determined using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Managed private credit fund investments are not classified within the fair value hierarchy because their fair value is determined using NAV or its equivalent as a practical expedient.

Private equity. These investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments, and investments in natural resources. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on our understanding of the investment funds. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include unobservable inputs such as cost, operating results, discounted future cash flows, and market based comparable data. These valuation inputs are unobservable. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Real estate. These investments are funds with a direct investment in pools of real estate properties. These funds are reported by the fund manager and are generally based on independent appraisals from sources with professional qualifications, typically using a combination of market comparables and discounted cash flows. These valuation inputs are unobservable. The fair value of real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

We evaluated our NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2020. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2020, there were no significant concentrations (generally defined as greater than 10 percent) of risk in our NDT assets.

See Note 10 — Asset Retirement Obligations for additional information on the NDT fund investments.

Rabbi Trust Investments. The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of executive management and directors. The Rabbi trusts’ assets are included in investments in the Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities, and life insurance policies. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets.

Deferred Compensation Obligations. Our deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. We include such plans in other current and noncurrent liabilities in the Consolidated Balance Sheets. The value of our deferred compensation obligations is based on the market value of the participants’ notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the table above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Investments in Equities. We hold certain investments in equity securities with readily determinable fair values in addition to those held within the NDT funds. These equity securities are valued based on quoted prices in active markets and are categorized as Level 1.

Deferred Purchase Price Consideration. We have DPP consideration for the sale of certain receivables of retail electricity. This amount is valued based on the sales price of the receivables net of allowance for credit losses based on accounts receivable aging historical experience coupled with specific identification through a credit monitoring process, which considers current conditions and forward-looking information such as industry trends, macroeconomic factors, changes in the regulatory environment, external credit ratings, publicly available news, payment status, payment history, and the exercise of collateral calls. Since the DPP consideration is based on the sales price of the receivables, it is categorized as Level 2 in the fair value hierarchy. See Note 6 — Accounts Receivable for additional information on the sale of certain receivables.

Mark-to-Market Derivatives. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives’ pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that we believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads, and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness, and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps, and options, model inputs are generally observable. Such instruments are categorized in Level 2. Our derivatives are predominantly at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. We consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data, in our assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding our significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Our Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. We utilize various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties, and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, we discount future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and our own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument’s market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.49 and $0.38 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See Note 16 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

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The following table presents the significant inputs to the forward curve used to value these positions:

Type of trade	Fair Value at December 31, 2020	Fair Value at December 31, 2019	Valuation Technique	Unobservable Input	2020 Range & Arithmetic Average		2019 Range & Arithmetic Average	
Mark-to-market derivatives – Economic hedges(a)(b)	$245	$558	Discounted Cash Flow	Forward power price	$ 2.25 – $ 163	$ 30	$ 9 – $ 180	$ 29
				Forward gas price	$ 1.57 – $ 7.88	$2.59	$ 0.83 – $ 10.72	$2.55
			Option Model	Volatility percentage	11% – 237%	32%	8% – 236%	70%
Mark-to-market derivatives – Proprietary trading(a)(b)	$ 23	$ 45	Discounted Cash Flow	Forward power price	$10 – $106	$ 27	$25 – $180	$ 33

(a) The valuation techniques, unobservable inputs, ranges, and arithmetic averages are the same for the asset and liability positions.

(b) The fair values do not include cash collateral posted on level three positions of $162 million and $214 million as of December 31, 2020 and December 31, 2019, respectively.

The inputs listed above, which are as of the balance sheet date, would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of our commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give us the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give us the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

19. Commitments and Contingencies

Commercial Commitments. Commercial commitments as of December 31, 2020, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2021	2022	2023	2024	2025	2026 and beyond
Letters of credit	$1,228	$1,164	$ 50	$14	$ —	$ —	$ —
Surety bonds(a)	926	873	53	—	—	—	—
Total commercial commitments	$2,154	$2,037	$103	$14	$ —	$ —	$ —

(a) Surety bonds — Guarantees issued related to contract and commercial agreements, excluding bid bonds.

Nuclear Insurance

We are subject to liability, property damage and other risks associated with major incidents at any of our nuclear stations. We have mitigated our financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2020, the current liability limit per incident is $13.8 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors at least once every five years with the last adjustment effective November 1, 2018. In accordance with the Price-Anderson Act, we maintain financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $13.3 billion per incident in funds available for public liability claims.

Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Our share of this secondary layer would be approximately $2.9 billion, however any amounts payable under this secondary layer would be capped at $434 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.8 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, we executed an Indemnity Agreement pursuant to which we agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees our obligations under this indemnity. See Note 21 — Variable Interest Entities for additional information on our operations relating to CENG.

We are required each year to report to the NRC the current levels and sources of property insurance that demonstrates we possess sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which we are a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years, NEIL has made distributions to its members, but we cannot predict the level of future distributions or if they will continue at all. Our portion of the annual distribution declared by NEIL is estimated to be $75 million for 2020, and was $136 million and $58 million for 2019 and 2018, respectively. In addition, in March 2018, NEIL declared a supplemental distribution. Our portion of the supplemental distribution declared by NEIL was $31 million. The distributions were recorded as a reduction to Operating and maintenance expense within the Consolidated Statements of Operations and Comprehensive Income.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and we cannot predict the level of future assessments, if any. The current maximum aggregate annual retrospective premium obligation for us is approximately $252 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

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NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which we are required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, we are unable to predict the timing of the availability of insurance proceeds to us and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by us will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For our insured losses, we are self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by us. Any such losses could have a material adverse effect on our financial statements.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, we are a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from our nuclear generating stations. In accordance with the NWPA and the Standard Contracts, we historically had paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. Due to the lack of a viable disposal program, the DOE reduced the SNF disposal fee to zero in May 2014. Until a new fee structure is in effect, we will not accrue any further costs related to SNF disposal fees. This fee may be adjusted prospectively to ensure full cost recovery.

We currently assume the DOE will begin accepting SNF in 2035 and use that date for purposes of estimating the nuclear decommissioning asset retirement obligations. The SNF acceptance date assumption is based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage.

The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance is expected to be delayed significantly. In August 2004, we and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse us, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at our nuclear stations pending the DOE's fulfillment of its obligations. Our settlement agreement does not include FitzPatrick and FitzPatrick does not currently have a settlement agreement in place. Calvert Cliffs, Ginna and Nine Mile Point each have separate settlement agreements in place with the DOE which were extended during 2020 to provide for the reimbursement of SNF storage costs through December 31, 2022. We submit annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

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Under the settlement agreements, we received total cumulative cash reimbursements of $1,455 million through December 31, 2020 for costs incurred. After considering the amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek, we received net cumulative cash reimbursements of $1,266 million. As of December 31, 2020 and 2019, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

	December 31, 2020	December 31, 2019
DOE receivable – current[(a)]	$129	$249
DOE receivable – noncurrent[(b)]	70	30
Amounts owed to co-owners[(c)]	(23)	(37)

(a) Recorded in Accounts receivable, other.

(b) Recorded in Deferred debits and other assets, other.

(c) Recorded in Accounts receivable, other. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The below table outlines the SNF liability recorded as of December 31, 2020 and 2019:

	December 31, 2020	December 31, 2019
Former ComEd units[(a)]	$1,082	$1,075
Fitzpatrick[(b)]	126	124
Total SNF Obligation	$1,208	$1,199

(a) ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of us), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. The unfunded liabilities for SNF disposal costs, including the one-time fee, were transferred to us as part of Exelon’s 2001 corporate restructuring.

(b) A prior owner of FitzPatrick elected to defer payment of the one-time fee of $34 million, with interest to the date of payment, for the FitzPatrick unit. As part of the FitzPatrick acquisition on March 31, 2017, we assumed a SNF liability for the DOE one-time fee obligation with interest related to FitzPatrick along with an offsetting asset, included in Other deferred debits and other assets, for the contractual right to reimbursement from NYPA, a prior owner of FitzPatrick, for amounts paid for the FitzPatrick DOE one-time fee obligation.

Interest for our SNF liabilities accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect for calculation of the interest accrual at December 31, 2020 was 0.096% for the deferred amount transferred from ComEd and 0.101% for the deferred FitzPatrick amount.

The following table summarizes sites for which we do not have an outstanding SNF Obligation:

Description	Sites
Fees have been paid	Former PECO units, Clinton and Calvert Cliffs
Outstanding SNF Obligation remains with former owners	Nine Mile Point, Ginna and TMI

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Environmental Remediation Matters

General. Our operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, we are generally liable for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances generated by us. We own or lease a number of real estate parcels, including parcels on which our operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, we are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, we cannot reasonably estimate whether we will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by us, environmental agencies or others. Additional costs could have a material, unfavorable impact on our financial statements.

As of December 31, 2020 and 2019, we had accrued undiscounted amounts of $121 million and $105 million, respectively, for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within the Consolidated Balance Sheets.

Cotter Corporation. The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon’s 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to us. Including Cotter, there are three PRPs participating in the West Lake Landfill remediation proceeding. Our investigation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing.

In September 2018, the EPA issued its Record of Decision (ROD) Amendment for the selection of a final remedy. The ROD Amendment modified the remedy previously selected by EPA in its 2008 ROD. While the 2008 ROD required only that the radiological materials and other wastes at the site be capped, the 2018 ROD Amendment requires partial excavation of the radiological materials in addition to the previously selected capping remedy. The ROD Amendment also allows for variation in depths of excavation depending on radiological concentrations. The EPA and the PRPs have entered into a Consent Agreement to perform the Remedial Design, which is expected to be completed by early 2022. In March 2019 the PRPs received Special Notice Letters from the EPA to perform the Remedial Action work. On October 8, 2019, Cotter (our indemnitee) provided a non-binding good faith offer to conduct, or finance, a portion of the remedy, subject to certain conditions. The total estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred collectively by the PRPs in fully executing the remedy, is approximately $280 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. We have determined that a loss associated with the EPA’s partial excavation and enhanced landfill cover remedy is probable and have recorded a liability, included in the table above, that reflects management’s best estimate of Cotter’s allocable share of the ultimate cost. Given the joint and several nature of this liability, the magnitude of our ultimate liability will depend on the actual costs incurred to implement the required remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Cotter’s associated allocable share could differ significantly once these uncertainties are resolved, which could have a material impact on our future financial statements.

One of the other PRPs has indicated it will be making a contribution claim against Cotter for costs that it has incurred to prevent the subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, we do not have sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on our financial statements.

In January 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. In September 2018, the PRPs agreed to an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater Remedial Investigation (RI)/Feasibility Study (FS). The purpose of this RI/FS is to define the nature and extent of any groundwater contamination from the West Lake Landfill site and evaluate remedial alternatives. We estimate the undiscounted cost for the groundwater RI/FS to be approximately $30 million. We determined a loss associated with the RI/FS is probable and have recorded a liability, included in the table above, that reflects management’s best estimate of Cotter’s allocable share of the cost among the PRPs. At this time we cannot predict the likelihood that, or the extent to which any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on our future financial statements.

In August 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government’s clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd’s (now our) indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government’s Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until August 31, 2021 so that settlement discussions can proceed. On August 3, 2020, the DOJ advised Cotter and the other PRPs that it is seeking approximately $90 million from all the PRPs and has directed that the PRPs must submit a good faith joint proposed settlement offer. We have determined that a loss associated with this matter is probable under our indemnification agreement with Cotter and have recorded an estimated liability, which is included in the table above.

Benning Road Site. In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility, which was deactivated in June 2012. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River.

Since 2013, Pepco and Pepco Energy Services (now us, pursuant to Exelon’s 2016 acquisition of PHI) have been performing RI work and have submitted multiple draft RI reports to the DOEE. In September 2019, we and Pepco issued a draft “final” RI report which DOEE approved on February 3, 2020. We and Pepco are developing a FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the FS, and approval by the DOEE, by September 16, 2021. After completion and approval of the FS, DOEE will prepare a Proposed Plan for public comment and then issue a ROD identifying any further response actions determined to be necessary. We have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims. We maintain a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by us or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

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At December 31, 2020 and 2019, we recorded estimated liabilities of approximately $89 million and $83 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2020, approximately $25 million of this amount related to 261 open claims presented to us, while the remaining $64 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2055, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, we monitor actual experience against the number of forecasted claims to be received and expected claim payments and evaluate whether adjustments to the estimated liabilities are necessary.

It is reasonably possible that additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued could have a material, unfavorable impact on our financial statements. However, management cannot reasonably estimate a range of loss beyond the amounts recorded.

Fund Transfer Restrictions. Under applicable law, we can pay dividends only from retained, undistributed or current earnings. A significant loss recorded by us, may limit the dividends that we can distribute to Exelon.

City of Everett Tax Increment Financing Agreement. On April 10, 2017, the City of Everett petitioned the Massachusetts Economic Assistance Coordinating Council (EACC) to revoke the 1999 tax increment financing agreement (TIF Agreement) relating to Mystic Units 8 and 9 on the grounds that the total investment in Mystic Units 8 and 9 materially deviates from the investment set forth in the TIF Agreement. On October 31, 2017, a three-member panel of the EACC conducted an administrative hearing on the City's petition. On November 30, 2017, the hearing panel issued a tentative decision denying the City's petition, finding that there was no material misrepresentation that would justify revocation of the TIF Agreement. On December 13, 2017, the tentative decision was adopted by the full EACC. On January 12, 2018, the City filed a complaint in Massachusetts Superior Court requesting, among other things, that the court set aside the EACC's decision, grant the City's request to decertify the Project and the TIF Agreement, and award the City damages for alleged underpaid taxes over the period of the TIF Agreement. On January 8, 2020, the Massachusetts Superior Court affirmed the decision of the EACC denying the City's petition. The City had until March 9, 2020 to appeal the decision and did not. As a result, the decision is final and the case is resolved. It is reasonably possible that property taxes assessed in future periods, including those following the expiration of the TIF Agreement on June 30, 2020, could be material to our financial statements.

General. We are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. We maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

20. Stock-Based Compensation Plans

Exelon grants stock-based awards to our employees through its LTIP, which primarily includes performance share awards, restricted stock units, and stock options. We also grant cash awards. The following table does not include expense related to these plans as they are not considered stock-based compensation plans under the applicable authoritative guidance.

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The following table presents the stock-based compensation expense included in our Consolidated Statements of Operations and Comprehensive Income:

	Year Ended December 31,		
	2020	2019	2018
Total stock-based compensation expense included in operating and maintenance expense	$27	$ 37	$ 77
Income tax benefit	(7)	(10)	(20)
Total after-tax stock-based compensation expense	$20	$ 27	$ 57

21. Variable Interest Entities

At December 31, 2020 and 2019, we consolidated several VIEs or VIE groups for which we are the primary beneficiary (see *Consolidated VIEs* below) and had significant interests in several other VIEs for which we do not have the power to direct the entities' activities and, accordingly, was not the primary beneficiary (see *Unconsolidated VIEs* below). Consolidated and unconsolidated VIEs are aggregated to the extent that the entities have similar risk profiles.

Consolidated VIEs

The table below shows the carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the consolidated financial statements as of December 31, 2020 and 2019. The assets, except as noted in the footnotes to the table below, can only be used to settle obligations of the VIEs. The liabilities, except as noted in the footnotes to the table below, are such that creditors, or beneficiaries, do not have recourse to our general credit.

	December 31, 2020	December 31, 2019
Cash and cash equivalents	$ 98	$ 163
Restricted cash and cash equivalents	44	85
Accounts receivable		
Customer	148	151
Other	36	39
Unamortized energy contract assets	22	23
Inventories, net		
Materials and supplies	244	227
Assets held for sale[(a)]	101	—
Other current assets	669	31
Total current assets	1,362	719
Property, plant and equipment, net	5,803	6,022
Nuclear decommissioning trust funds	3,007	2,741
Unamortized energy contract assets	249	250
Other noncurrent assets	42	73
Total noncurrent assets	9,101	9,086
Total assets[(b)]	$10,463	$9,805
Long-term debt due within one year	$ 68	$ 523
Accounts payable	81	106
Accrued expenses	70	70
Unamortized energy contract liabilities	4	8
Liabilities held for sale[(a)]	16	—

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	December 31, 2020	December 31, 2019
Other current liabilities	5	3
Total current liabilities	244	710
Long-term debt	889	504
Asset retirement obligations	2,318	2,128
Unamortized energy contract liabilities	—	1
Other noncurrent liabilities	129	89
Total noncurrent liabilities	3,336	2,722
Total liabilities[c]	$3,580	$3,432

(a) We entered into an agreement for the sale of a significant portion of our solar business. As a result of this transaction, in the fourth quarter of 2020, we reclassified the consolidated VIEs' solar assets and liabilities as held for sale. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the sale of the solar business.

(b) Our balances include unrestricted assets for current unamortized energy contract assets of $22 million and $23 million, Property, plant, and equipment of $1 million and $20 million, non-current unamortized energy contract assets of $249 million and $250 million, and Assets held for sale of $9 million and $0 million as of December 31, 2020 and 2019, respectively.

(c) Our balances include liabilities with recourse of $8 million and $3 million as of December 31, 2020 and 2019, respectively.

As of December 31, 2020 and 2019, our consolidated VIEs consist of:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason we are the primary beneficiary:
CENG — A joint venture between us and EDF. We have a 50.01% equity ownership in CENG. See additional discussion below.	Disproportionate relationship between equity interest and operational control as a result of the NOSA described further below.	We conduct the operational activities.
EGRP — A collection of wind and solar project entities. We have a 51% equity ownership in EGRP. See additional discussion below.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
Bluestem Wind Energy Holdings, LLC — A Tax Equity structure which is consolidated by EGRP. We are a minority interest holder.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
Antelope Valley — A solar generating facility, which is 100% owned by us. Antelope Valley sells all of its output to PG&E through a PPA.	The PPA contract absorbs variability through a performance guarantee.	We conduct all activities.
Equity investment in distributed energy company — we have a 31% equity ownership. This distributed energy company has an interest in an unconsolidated VIE. (See	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.

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Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason we are the primary beneficiary:
Unconsolidated VIEs disclosure below). We fully impaired this investment in the third quarter of 2019. Refer to Note 12 — Asset Impairments for additional information.		
NER — A bankruptcy remote, special purpose entity which is 100% owned by us, which purchases certain of our customer accounts receivable arising from the sale of retail electricity. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. Refer to Note 6 — Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	We conduct all activities.

CENG — On April 1, 2014, we, CENG, and subsidiaries of CENG executed the NOSA pursuant to which we conduct all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of our nuclear fleet, subject to the CENG member rights of EDF.

EDF has the option to sell its 49.99% equity interest in CENG to us. On November 20, 2019, we received notice of EDF's intention to exercise the put option to sell its interest in CENG to us and the put automatically exercised on January 19, 2020. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

We provide the following support to CENG:

- We executed an Indemnity Agreement pursuant to which we agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees our obligations under this Indemnity Agreement. See Note 19 — Commitments and Contingencies for more details.
- We and EDF share in the $688 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance.
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

EGRP — EGRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by EGRP. We own a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by EGRP. While we or EGRP own 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and wind entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. We are the primary beneficiary of these solar and wind entities that qualify as VIEs because we control the design, construction, and operation of the facilities. There is limited recourse to us related to certain solar and wind entities.

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In 2017, our interests in EGRP were contributed to and are pledged for the EGR IV non-recourse debt project financing structure. Refer to Note 17 — Debt and Credit Agreements for additional information.

Unconsolidated VIEs

Our variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected in the Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in the Consolidated Balance Sheets that relate to our involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, us for the deliveries associated with the current billing cycles under the commercial agreements.

As of December 31, 2020 and 2019, we had significant unconsolidated variable interests in several VIEs for which we were not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements.

The following table presents summary information about our significant unconsolidated VIE entities:

	December 31, 2020			December 31, 2019		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$777	$401	$1,178	$636	$443	$1,079
Total liabilities[(a)]	61	223	284	33	227	260
Our ownership interest in VIE[(a)]	—	157	157	—	191	191
Other ownership interests in VIE[(a)]	716	21	737	604	25	629

(a) These items represent amounts on the unconsolidated VIE balance sheets, not in our Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. We do not have any exposure to loss as they do not have a carrying amount in the equity investment VIEs as of December 31, 2020 and 2019.

As of December 31, 2020 and 2019, the unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
Equity investments in distributed energy companies — 1) We have a 90% equity ownership in a distributed energy company. 2) We, via a consolidated VIE, have a 90% equity ownership in another distributed energy company (See Consolidated VIEs disclosure above). We fully impaired this investment in the third quarter of 2019. Refer to Note 12 — Asset Impairments for additional	Similar structures to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We do not conduct the operational activities.

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Unconsolidated VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
information.		
Energy Purchase and Sale agreements — We have several energy purchase and sale agreements with generating facilities.	PPA contracts that absorb variability through fixed pricing.	We do not conduct the operational activities.

22. Supplemental Financial Information

Supplemental Statement of Operations Information

The following table provides additional information about material items recorded in the Consolidated Statements of Operations and Comprehensive Income.

	Taxes other than income taxes		
	For the years ended December 31,		
	2020	2019	2018
Gross receipts[a]	$ 99	$112	$114
Property	265	274	273
Payroll	113	115	130

(a) Represent gross receipts taxes related to our retail operations. The offsetting collection of gross receipts taxes from customers is recorded in revenues in the Consolidated Statements of Operations and Comprehensive Income.

	Other, Net		
	For the years ended December 31,		
	2020	2019	2018
Decommissioning-related activities:			
Net realized income on NDT funds[a]			
Regulatory Agreement Units	$ 185	$ 297	$ 506
Non-regulatory Agreement Units	160	363	302
Net unrealized gains on NDT funds			
Regulatory Agreement Units	724	795	(715)
Non-regulatory Agreement Units	391	411	(483)
Regulatory offset to NDT fund-related activities[b]	(729)	(876)	171
Decommissioning-related activities	731	990	(219)
Unrealized gains from equity investments[c]	186	—	—

(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.

(b) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of income taxes related to all NDT fund activity for those units. See Note 10 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(c) Unrealized gains resulting from equity investments without readily determinable fair values that

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became publicly traded entities in the fourth quarter of 2020 and were fair valued based on quoted market prices of the stocks as of December 31, 2020.

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Consolidated Statements of Cash Flows.

	Depreciation, amortization and accretion		
	For the years ended December 31,		
	2020	2019	2018
Property, plant and equipment[(a)]	$2,070	$1,485	$1,748
Amortization of intangible assets, net[(a)]	53	50	49
Amortization of energy contract assets and liabilities[(b)]	30	21	14
Nuclear fuel[(c)]	983	1,016	1,115
ARO accretion[(d)]	500	491	489
Total depreciation, amortization and accretion	$3,636	$3,063	$3,415

(a) Included in Depreciation and amortization in the Consolidated Statements of Operations and Comprehensive Income.

(b) Included in Operating revenues or Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.

(c) Included in Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.

(d) Included in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

	Cash paid (refunded) during the year:		
	For the years ended December 31,		
	2020	2019	2018
Interest (net of amount capitalized)	$331	$373	$369
Income taxes (net of refunds)	70	(44)	746

	Other non-cash operating activities:		
	For the years ended December 31,		
	2020	2019	2018
Pension and non-pension postretirement benefit costs	$ 115	$ 135	$204
Allowance for credit losses	17	31	48
Other decommissioning-related activity[(a)]	(659)	(506)	(2)
Energy-related options[(b)]	104	22	10
Severance costs	90	—	—
Provision for excess and obsolete inventory	128	—	—
Amortization of operating ROU asset	155	172	—

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of operating revenues, ARO updates and accretion, ARC amortization,

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investment income and income taxes related to all NDT fund activity for these units. See Note 10 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

The following table provides a reconciliation of cash, restricted cash, and cash equivalents reported within the Consolidated Balance Sheets that sum to the total of the same amounts in the Consolidated Statements of Cash Flows.

	December 31, 2020	December 31, 2019	December 31, 2018	December 31, 2017
Cash and cash equivalents	$226	$303	$750	$416
Restricted cash and cash equivalents	89	146	153	138
Cash, restricted cash, and cash equivalents – Held for Sale	12	—	—	—
Total cash, restricted cash, and cash equivalents	$327	$449	$903	$554

Supplemental Balance Sheet Information

The following tables provide additional information about material items recorded in the Consolidated Balance Sheets.

	Investments	
	December 31, 2020	December 31, 2019
Equity method investments:		
Other equity method investments	$ 65	$ 71
Other investments:		
Employee benefit trusts and investments[(a)]	61	54
Equity investments without readily determinable fair values	55	69
Other available for sale debt security investments	3	41
Total investments	$184	$235

(a) Debt and equity security investments are recorded at fair market value.

	Accrued expenses	
	December 31, 2020	December 31, 2019
Compensation-related accruals[(a)]	$426	$422
Taxes accrued	229	222
Interest accrued	44	65

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

23. Related Party Transactions

Operating revenues from affiliates

The following table presents our Operating revenues from affiliates:

	For the Years Ended December 31,		
	2020	2019	2018
ComEd[(a)]	$ 330	$ 369	$ 523
PECO[(b)]	190	158	128
BGE[(c)]	315	289	260
PHI	367	353	355
Pepco[(d)]	279	264	206
DPL[(e)]	75	70	120
ACE[(f)]	13	19	29
Other	9	3	2
Total operating revenues from affiliates	$1,211	$1,172	$1,268

(a) We have an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. We also sell RECs and ZECs to ComEd.

(b) We provide electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, we have a ten-year agreement with PECO to sell solar AECs.

(c) We provide a portion of BGE's energy requirements under its MDPSC-approved market-based SOS commodity programs.

(d) We provide electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.

(e) We provide a portion of DPL's energy requirements under its MDPSC and DPSC approved market based SOS and gas commodity programs.

(f) We provide electric supply to ACE under contracts executed through ACE's competitive procurement process.

Service Company Costs for Corporate Support

We receive a variety of corporate support services from BSC. See Note 1 — Significant Accounting Policies for additional information regarding BSC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in millions, except per share data unless otherwise noted)

The following table presents the service company costs allocated to us:

Operating and maintenance from affiliates			Capitalized costs		
For the years ended December 31,			For the years ended December 31,		
2020	2019	2018	2020	2019	2018
$552	$570	$652	$54	$66	$67

Current Receivables from/Payables to affiliates

The following table presents current receivables from affiliates and current payables to affiliates:

	December 31, 2020		December 31, 2019	
	Receivables from affiliates:	Payables to affiliates:	Receivables from affiliates:	Payables to affiliates:
ComEd	$ 78	$ 13	$ 78	$ 27
PECO	17	—	27	—
BGE	11	—	28	—
Pepco	13	—	34	—
DPL	3	—	7	—
ACE	6	—	7	—
BSC	—	72	—	67
PHISCO	—	—	—	—
Other	25	22	9	23
Total	$153	$107	$190	$117

Borrowings from Exelon intercompany money pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. We participate in the Exelon money pool.

Noncurrent Receivables from/Payables to affiliates

We have long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 10 — Asset Retirement Obligations for additional information.

The following table presents noncurrent receivables from affiliates at ComEd and PECO which are recorded as noncurrent payables to affiliates on our Consolidated Balance Sheets:

	December 31,	
	2020	2019
ComEd	$2,541	$2,622
PECO	475	480

Long-term debt to affiliates

In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and our subsidiaries (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term debt to affiliates in our Consolidated Balance Sheets.

24. Subsequent Events

Impacts of February 2021 Weather Events and Texas-based Generating Assets Outages

Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced periodic outages as a result of historically severe cold weather conditions. In addition, those weather conditions drove increased demand for service, limited the availability of natural gas to fuel power plants, dramatically increased wholesale power prices and also increased gas prices in certain regions. In response to the high demand and significantly reduced total generation on the system, ERCOT implemented load reductions to maintain the reliability of the grid and required the use of an administrative price cap of $9,000 per megawatt hour during load shedding events.

We estimate the impact to Net income for the first quarter of 2021 arising from these market and weather conditions to be approximately $560 million to $710 million. The estimated impact includes favorable results in certain regions within our wholesale gas business. The ultimate impact to our consolidated financial statements may be affected by a number of factors, including final settlement data, the impacts of customer and counterparty credit losses, any state sponsored solutions to address the financial challenges caused by the event, and litigation and contract disputes which may result.

We used a combination of commercial paper and letters of credit to manage collateral needs and have posted approximately $1.4 billion of collateral with ERCOT as of February 22, 2021. We continue to believe we have sufficient cash on hand and available capacity on our revolver, which was $2.4 billion as of February 22, 2021, to meet our liquidity requirements.

Exhibit 99.2

Important Notice Regarding the Availability of Materials

EXELON CORPORATION

Exelon

D66647-Z81905

You are receiving this communication because you hold common stock in Exelon Corporation ("Exelon"). Exelon has released informational materials regarding the spin-off of Constellation Energy Corporation ("Constellation") and its consolidated subsidiaries from Exelon that are now available for your review. **This notice provides instructions on how to access Exelon materials for informational purposes only.**

To effectuate the spin-off, Exelon will distribute on a pro rata basis to its stockholders all of the issued and outstanding shares of Constellation common stock held by it. Immediately following the distribution, which will be effective as of the date and time referenced in the Information Statement that Constellation has prepared in connection with the spin-off, Constellation will be an independent, publicly traded company. Exelon is not soliciting proxy or consent authority in connection with the spin-off.

The materials consist of the Information Statement, that Constellation has prepared in connection with the spin-off. You may view the materials online at *www.materialnotice.com* and easily request a paper or e-mail copy (see reverse side).

See the reverse side for instructions on how to access materials.

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