# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, DC 20549**

# FORM 8-K

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

**Date of Report (Date of earliest event reported): June 15, 2018**

# VISTRA ENERGY CORP.
**(Exact name of registrant as specified in its charter)**

| Delaware | 001-38086 | 36-4833255 |
|---|---|---|
| (State or other jurisdiction of incorporation or organization) | (Commission File Number) | (I.R.S. Employer Identification No.) |

| 6555 Sierra Drive<br>Irving, TX | 75039 |
|---|---|
| (Address of principal executive offices) | (Zip Code) |

**(214) 812-4600**
**(Registrant's telephone number, including area code)**

**N/A**
**(Former name or former address, if changed since last report)**

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.l4a-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))

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

**Item 8.01. Other Events.**

Vistra Energy Corp. (the "Company") is filing this Current Report on Form 8-K to update the presentation of certain financial information and related disclosures contained in its Annual Report on Form 10-K for the year ended December 31, 2017 (the "2017 Form 10-K") which was filed with the Securities and Exchange Commission ("SEC") on February 26, 2018.

This Form 8-K retrospectively revises our financial statements as of December 31, 2017, and for all periods presented, to reflect (i) the establishment of a new reportable segment, the Asset Closure segment, and (ii) the adoption of Accounting Standards Update ("ASU") 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* . These updates are consistent with the presentation in the Company's Quarterly Report on Form 10-Q for the three months ended March 1, 2018 filed with the SEC on May 4, 2018. The retrospectively revised Items contained in the Company's 2017 Form 10-K are presented in Exhibits 99.1, 99.2 and 99.3 to this Form 8-K.

The exhibits to this Current Report on Form 8-K supersede the following Items in the 2017 Form 10-K to reflect, retrospectively, the changes resulting from the establishment of a new reportable segment and the adoption of the ASU referenced above:

- Part I, Item 1. Business
- Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A")
- Part II, Item 8. Financial Statements and Supplementary Data and Schedule I of Part IV, Item 15. Exhibits, Financial Statement Schedules

All other information in the 2017 Form 10-K remains unchanged. Unaffected portions of the 2017 Form 10-K have not been repeated in, and are not amended or modified by, this Current Report on Form 8-K or Exhibits 99.1, 99.2 and 99.3 to this Form 8-K. This Current Report on Form 8-K does not reflect events occurring subsequent to the filing of the 2017 Form 10-K and does not modify or update the disclosures therein in any way, other than as required to reflect the reclassifications as described above and as set forth in the exhibits attached hereto. Without limitation to the foregoing, this Current Report on Form 8-K does not purport to update the business description or MD&A in the 2017 Form 10-K for any information, uncertainties, risks, events or trends occurring or known to management. For developments since the filing of the 2017 Form 10-K, please refer to the the Company's Quarterly Report on Form 10-Q for the three months ended March 1, 2018 filed with the SEC on May 4, 2018, as well as other filings of the Company made with the SEC. The information in this Current Report on Form 8-K should be read in conjunction with the 2017 Form 10-K and such subsequent filings.

**Item 9.01 Financial Statements and Exhibits.**

**(d) Exhibits**

| Exhibit Number | Description of Exhibit |
|---|---|
| 23.1 * | Consent of Deloitte and Touche LLP |
| 99.1 * | Part I, Item 1. Business, revised only to reflect a change in reporting segment |
| 99.2 * | Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, revised only to reflect a change in reporting segment and the adoption of a recently issued accounting standard update |
| 99.3 * | Part II, Item 8. Financial Statements and Supplementary Data and Schedule I of Part IV, Item 15. Exhibits, Financial Statement Schedules, revised only to reflect a change in reporting segment and the adoption of a recently issued accounting standard update |
| 101.INS * | XBRL Instance Document |
| 101.SCH * | XBRL Taxonomy Extension Schema Document |
| 101.CAL * | XBRL Taxonomy Extension Calculation Document |
| 101.DEF * | XBRL Taxonomy Extension Definition Document |
| 101.LAB * | XBRL Taxonomy Extension Labels Document |
| 101.PRE * | XBRL Taxonomy Extension Presentation Document |

* Filed herewith

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Vistra Energy Corp.

Dated: June 15, 2018

/s/ Christy Dobry

| | |
|---|---|
| Name: | Christy Dobry |
| Title: | Vice President & Controller |

**Exhibit 23.1**

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-219687 on Form S-8 of our report dated February 26, 2018 (June 15, 2018 as to the retrospective adjustments for the adoption of ASU 2016-18 described in Notes 1 and 21 and the schedule listed in the Index at Item 15(b) and the change in reportable segments described in Notes 1 and 20), relating to the consolidated financial statements and financial statement schedule of Vistra Energy Corp. and its subsidiaries and its Predecessor Company (which report expresses an unqualified opinion and includes explanatory paragraphs regarding the adoption of ASU 2016-18 and the emergence from bankruptcy and the non-comparability of Vistra Energy Corp. and its subsidiaries to its Predecessor Company), appearing in this Current Report on Form 8-K.

/s/ Deloitte & Touche LLP

Dallas, Texas
June 15, 2018

**Exhibit 99.1**

## Item 1. BUSINESS

The following discussion should be read together with the consolidated financial statements and the notes thereto included in Exhibit 99.3 attached to this Current Report on Form 8-K. All references to notes to our consolidated financial statements refer to the financial statements included in Exhibit 99.3 attached to this Current Report on Form 8-K. All references to our Annual Report on Form 10-K refer to our Form 10-K for the year ended December 31, 2017 which was filed with the Securities and Exchange Commission on February 26, 2018.

References in this report to "we," "our," "us" and "the Company" are to Vistra Energy and/or its subsidiaries, as apparent in the context. See Glossary for defined terms.

### *Business*

Vistra Energy is a holding company operating an integrated power business in Texas. Through our Luminant and TXU Energy subsidiaries, we are engaged in competitive electricity market activities including electricity generation, wholesale energy sales and purchases, commodity risk management activities, and retail sales of electricity to end users, all largely in the ERCOT market.

TXU Energy is the largest retailer of electricity in Texas, with approximately 1.7 million residential, commercial and industrial customers. Luminant is the largest generator of electricity in ERCOT, operating approximately 13,600 MW of installed capacity in ERCOT.

We have three reportable segments: (i) our Wholesale Generation segment, consisting largely of Luminant; (ii) our Retail Electricity segment, consisting largely of TXU Energy, and (iii) our Asset Closure segment, consisting of financial results associated with retired plants and mines.

As of December 31, 2017, we had approximately 4,150 full-time employees, including approximately 1,630 employees under collective bargaining agreements.

### *Merger*

On October 29, 2017, Vistra Energy and Dynegy Inc., a Delaware corporation (Dynegy), entered into an Agreement and Plan of Merger (the Merger Agreement) pursuant to which, upon closing (which is expected to occur in the second quarter of 2018), Dynegy will merge with and into Vistra Energy (the Merger), with Vistra Energy surviving the Merger and the shareholders of Vistra Energy and Dynegy receiving 79% and 21%, respectively, of the equity of the combined company. See Item 1. *Business* - Recent Developments below for a more detailed description of the Merger and the Merger Agreement.

*Business Strategy*

Our business strategy is to deliver long-term stakeholder value through a focus on the following areas:

- *Integrated business model.* We believe the key factor that distinguishes us from others in our industry is the integrated nature of our business ( *i.e.* , pairing Luminant's reliable and efficient mining, generating and wholesale commodity risk management capabilities with TXU Energy's retail platform). Our business strategy will be guided by our integrated business model because we believe it is our core competitive advantage and differentiates us from our non-integrated competitors. We believe our integrated business model creates a unique opportunity because, relative to our non-integrated competitors, it reduces the effects of commodity price movements and contributes to earnings stability. Consequently, our integrated business model is at the core of our business strategy.

- *Strong balance sheet and disciplined capital allocation.* Like any energy-focused business, we are potentially subject to significant commodity price volatility and capital costs. Accordingly, our strategy has been, and will continue to be, to maintain a strong balance sheet. As a result, we are focused on maintaining prudent financial leverage supported by readily accessible, flexible and diverse sources of liquidity. Our ongoing capital allocation priorities primarily include making necessary capital investments to maintain the safety and reliability of our facilities. Because we believe cost discipline and strong management of our assets and commodity positions are necessary to deliver long-term value to our stakeholders, we generally make capital allocation decisions that we believe will lead to attractive cash returns on investment.

- *Superior customer service.* Through TXU Energy, we serve the retail electricity needs of end-use residential, small business, commercial and industrial electricity customers through multiple sales and marketing channels. In addition to benefitting from our integrated business model, we leverage our brand, our commitment to a consistent and reliable product offering, the backstop of the electricity generated by our generation fleet, our wholesale commodity risk management operations and our strong customer service to differentiate our products and services from our competitors. We strive to be at the forefront of innovation with new offerings and customer experiences to reinforce our value proposition. We maintain a focus on solutions that give our customers choice, convenience and control over how and when they use electricity and related services, including Free Nights and Solar Days residential plans, MyEnergy Dashboard [SM] , TXU iThermostat product and mobile solution, the TXU Energy Rewards program, the TXU Energy Green Up [SM] renewable energy credit program and a diverse set of solar options. Our focus on superior customer service will guide our efforts to acquire new residential and commercial customers, serve and retain existing customers and maintain valuable sales channels for our electricity generation resources. We believe our customer service, products and trusted brand have resulted in TXU Energy maintaining the highest residential customer retention rate of any Texas retail electric provider in its respective core market.

- *Excellence in operations while maintaining an efficient cost structure.* We believe that operating our facilities in a safe, reliable, environmentally compliant, and cost-effective and efficient manner is a foundation for delivering long-term stakeholder value. We also believe value increases as a function of making disciplined investments that enable our generation facilities to operate not only effectively and efficiently, but also safely, reliably and in an environmentally compliant manner. We believe that an ongoing focus on operational excellence and safety is a key component to success in a highly competitive environment and is part of the unique value proposition of our integrated model. Additionally, we are committed to optimizing our cost structure and implementing enterprise-wide process and operating improvements without compromising the safety of our communities, customers and employees. In connection with Emergence, in addition to significantly reducing our debt levels, we implemented certain cost-reduction actions in order to better align and right-size our cost structure. We believe we have a highly effective and efficient cost structure and that our cost structure supports excellence in our operations.

- *Integrated hedging and commercial management.* Our commercial team is focused on managing risk, through opportunistic hedging, and optimizing our assets and business positions. We actively manage our exposure to wholesale electricity prices in ERCOT, on an integrated basis, through contracts for physical delivery of electricity, exchange-traded and over-the-counter financial contracts, ERCOT term, day-ahead and real-time market transactions, and bilateral contracts with other wholesale market participants, including other power generators and end-user electricity customers. These hedging activities include short-term agreements, long-term electricity sales contracts and forward sales of natural gas through financial instruments. The historically positive correlation between natural gas prices and wholesale electricity prices in ERCOT has provided us an opportunity to manage our exposure to the variability of wholesale electricity prices through natural gas hedging activities. We seek to hedge near-term cash flow and optimize long term value through hedging and forward sales contracts. We believe our integrated hedging and commercial management strategy, in combination with a strong balance sheet and strong liquidity profile, will provide a long-term advantage through cycles of higher and lower commodity prices.

- *Growth and enhancement.* Our growth strategy leverages our core capabilities of multi-channel retail marketing in a large and competitive market, operating large-scale, environmentally sensitive, and diverse assets across a variety of fuel technologies, fuel logistics and management, commodity risk management, cost control, and energy infrastructure investing. We intend to opportunistically evaluate acquisitions of high-quality energy infrastructure assets and businesses that complement these core capabilities and enable us to achieve operational or financial synergies. While we are intent on growing our business and creating value for our stockholders, we are committed to making disciplined investments that are consistent with our focus on maintaining a strong balance sheet and strong liquidity profile. As a result, consistent with our disciplined capital allocation approval process, growth opportunities we pursue will need to have compelling economic value in addition to fitting with our business strategy.

- *Corporate responsibility and citizenship.* We are committed to providing safe, reliable, cost-effective and environmentally compliant electricity for the communities and customers we serve. We strive to improve the quality of life in the communities in which we operate. We are also committed to being a good corporate citizen in the communities in which we conduct operations. We and our employees are actively engaged in programs intended to support and strengthen the communities in which we conduct operations. Our foremost giving initiatives are through the United Way and TXU Energy Aid campaigns. TXU Energy Aid has served as an integral resource for social service agencies that assist families in need across Texas pay their electricity bills.

***The ERCOT Market***

ERCOT is an ISO that manages the flow of electricity from approximately 78,000 MW of installed capacity to approximately 24 million Texas customers, representing approximately 90% of the state's electric load and spanning approximately 75% of its geography, as of December 31, 2017. Population growth in Texas is currently expanding at well above the national average rate, with a growth rate of 12.1% between July 2010 and July 2017, more than double the U.S. population growth rate of 5.3% during the same period, according to the U.S. Census Bureau. ERCOT accounts for approximately 32% of the competitively served retail load in the U.S., and residential consumers in the ERCOT market consume approximately 30% more electricity than the average U.S. residential consumer according to the U.S. Energy Information Administration (EIA). Total ERCOT power demand has grown at a compounded annual growth rate of approximately 1.4% from 2006 through 2016, compared to a range of -0.3% to 0.2% in other U.S. markets, according to ERCOT and the EIA, respectively.

As an energy-only market, ERCOT's market design is distinct from other competitive electricity markets in the United States. Other markets 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. On June 1, 2014, ERCOT implemented the Operating Reserve Demand Curve (ORDC), pursuant to which wholesale electricity prices in the real-time electricity market increase automatically as available operating reserves decrease below defined threshold levels, creating a price adder. When operating reserves drop to 2,000 MW or less, the ORDC automatically adjusts power prices to the established value of lost load (VOLL), which is set at $9,000/MWh. Because ERCOT has limited excess generation capacity to meet high demand days due to its minimal import capacity, and peaking facilities have high operating costs, the marginal price of supply rapidly increases during periods of high demand. Historically, elevated temperatures in the summer months have driven high electricity demand in ERCOT. Many generators benefit from these sporadic periods of "scarcity pricing" in which power prices may increase significantly, up to the current $9,000/MWh price cap.

Transactions in ERCOT take place in two key markets: the day-ahead market and the real-time market. The day-ahead market is a voluntary, forward electricity market conducted the day before each operating day in which generators and purchasers of electricity may bid for one or more hours of electricity supply or consumption. The real-time market is a spot market in which electricity may be sold in five-minute intervals. The day-ahead market provides market participants with visibility into where prices are expected to clear, and the prices are not impacted by subsequent events. Conversely, the real-time market exposes purchasers to the risk of transient operational events and price spikes. These two markets allow market participants to manage their risk profile by adjusting their participation in each market. In addition, ERCOT uses ancillary services to maintain system reliability, including regulation service-up, regulation service-down, responsive reserve service and non-spinning reserve service. Regulation service up and down are used to balance the grid in a near-instantaneous fashion when supply and demand fluctuate due to a variety of factors, such as weather, generation outages, renewable production intermittency and transmission outages. Responsive reserves and non-spinning reserves are used by ERCOT when the grid is at, near or recovering from a state of emergency due to inadequate generation. Because ERCOT has one of the highest concentrations of wind capacity generation among United States markets, the ERCOT market is more susceptible to fluctuations in wholesale electricity supply due to intermittent wind production, making ERCOT more vulnerable to periods of generation scarcity.

***Operating Segments***

Our operating segments consist of (i) the Wholesale Generation segment, consisting largely of Luminant; (ii) the Retail Electricity segment, consisting largely of TXU Energy, and (iii) the Asset Closure segment, consisting of financial results associated with retired plants and mines. See Note 20 to the Financial Statements for additional information related to our operating segments.

*Wholesale Generation Segment*

As described in Item 2. *Properties* , our power generation fleet is diverse and flexible in terms of dispatch characteristics as our fleet includes baseload, intermediate/load following and peaking generation. Our wholesale commodity risk management business is responsible for dispatching our generation fleet in response to market needs after implementing portfolio optimization strategies, thus linking and integrating the generation fleet production with our retail customer and wholesale sales opportunities. Market demand, also known as load, faced by an electric power system such as ERCOT varies from moment to moment as a result of changes in business and residential demand, which is often driven by weather. Unlike most other commodities, the production and consumption of electricity must remain balanced on an instantaneous basis. There is a certain baseline demand for electricity across an electric power system that occurs throughout the day, which is typically satisfied by baseload generating units with low variable operating costs. Baseload generating units can also increase output to satisfy certain incremental demand and reduce output when demand is unusually low. Intermediate/load-following generating units, which can more efficiently change their output to satisfy increases in demand, typically satisfy a large proportion of changes in intraday load as they respond to daily increases in demand or unexpected changes in supply created by reduced generation from renewable resources or other generator outages. Peak daily loads may be satisfied by peaking units. Peaking units are typically the most expensive to operate, but they can quickly start up and shut down to meet brief peaks in demand. In general, baseload units, intermediate/load following units and peaking units are dispatched into the ERCOT grid in order from lowest to highest variable cost. Price formation in ERCOT, as with other competitive power markets in the U.S., is typically based on the highest variable cost unit that clears the market to satisfy system demand at a given point in time.

*Retail Electricity Segment*

Texas has one of the fastest growing populations of any state in the U.S. and has a diverse economy, which has resulted in a significant and growing competitive retail electricity market. We are an active participant in the competitive ERCOT market and continue to be a market leader, which we believe is driven by, among other things, having one of the lowest customer complaint rates according to the PUCT and having an integrated power generation and wholesale operation that allows us to efficiently obtain the electricity needed to serve our customers at the lowest cost. We provided electricity to approximately 24% and 18% of the residential and commercial customers in ERCOT, respectively, as of December 31, 2017. We believe that we have differentiated ourselves by providing a distinctive customer experience predicated on delivering reliable and innovative power products and solutions to our customers, such as Free Nights and Solar Days residential plans, MyEnergy Dashboard SM , TXU iThermostat product and mobile solution, the TXU Energy Rewards program, the TXU Energy Green UP SM renewable energy credit program and a diverse set of solar options, which give our customers choice, convenience and control over how and when they use electricity and related services. We competitively market electricity and related services to acquire, serve and retain retail customers. We believe we are situated to better serve our retail customers through our unique affiliation with our wholesale commodity risk management personnel who can structure products and contracts in a way that offers significant value compared to stand-alone retail electric providers. Additionally, our wholesale commodity risk management business protects our retail business from power price volatility by allowing us to bypass bid-ask spread in the market (particularly for illiquid products and time periods), which results in significantly lower collateral costs for our retail business as compared to other, non-integrated retail electric providers. Moreover, our retail business reduces, to some extent, the exposure of our wholesale generation business to wholesale power price volatility. This is because the retail load requirements of our retail operations (primarily TXU Energy) provide a natural offset to the length of Luminant's generation portfolio thereby reducing the exposure to wholesale power price volatility as compared to a non-integrated independent power producer.

*Asset Closure Segment*

The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines. Separately reporting the Asset Closure segment provides management with better information related to the performance and earnings power of Vistra Energy's ongoing operations and facilitates management's focus on minimizing the cost associated with decommissioning and reclamation of retired plants and mines.

***Seasonality***

The demand for and market prices of electricity and natural gas are affected by weather. As a result, our operating results may fluctuate on a seasonal basis, and more severe weather conditions such as heat waves or extreme winter weather may make such fluctuations more pronounced. The pattern of this fluctuation may change depending on, among other things, the retail load served and the terms of contracts to purchase or sell electricity.

***Competition***

Competition in ERCOT, as in other electricity markets, is impacted by electricity and fuel prices, congestion along the power grid, subsidies provided by state and federal governments for new generation facilities, new market entrants, construction of new generating assets, technological advances in power generation, the actions of environmental and other regulatory authorities, and other factors. We primarily compete with other electricity generators and retailers based on our ability to generate electric supply, market and sell electricity at competitive prices and to efficiently utilize transportation from third-party pipelines and transmission from electric utilities to deliver electricity to end-users. Competitors in the generation and retail power markets in which we participate include regulated utilities, industrial companies, non-utility generators, competitive subsidiaries of regulated utilities, independent power producers, REPs and other energy marketers. See Item 1A. *Risk Factors* for additional information concerning the risks faced with respect to the competitive energy markets in which we operate.

***Brand Value***

Our TXU Energy TM brand, which has been used to sell electricity to customers in the competitive retail electricity market in Texas for approximately 16 years, is registered and protected by trademark law and is the only material intellectual property asset that we own. As of December 31, 2017, we have reflected an intangible asset on our balance sheet for the TXU Energy TM brand of approximately $1.2 billion (see Note 7 to the Financial Statements).

***Recent Developments***

On October 29, 2017, Vistra Energy and Dynegy, entered into the Merger Agreement. The following description of the Merger Agreement does not purport to be a complete description and is qualified in its entirety by reference to the full text of the Merger Agreement filed as Exhibit 2.1 to our Current Report on Form 8-K filed on October 31, 2017.

Upon the terms and subject to the conditions set forth in the Merger Agreement, which has been approved by the boards of directors of Vistra Energy and Dynegy, Dynegy will merge with and into Vistra Energy, with Vistra Energy continuing as the surviving corporation. The Merger is intended to qualify as a tax-free reorganization under the Internal Revenue Code of 1986, as amended, so that none of Vistra Energy, Dynegy or any of the Dynegy stockholders will recognize any gain or loss in the transaction, except that Dynegy stockholders could recognize a gain or loss with respect to cash received in lieu of fractional shares of Vistra Energy's common stock. We expect that Vistra Energy will be the acquirer for both federal tax and accounting purposes.

Upon the closing of the Merger, each issued and outstanding share of Dynegy common stock, par value $0.01 per share, other than shares owned by Vistra Energy or its subsidiaries, held in treasury by Dynegy or held by a subsidiary of Dynegy, will automatically be converted into the right to receive 0.652 shares of common stock, par value $0.01 per share, of Vistra Energy (the Exchange Ratio), except that cash will be paid in lieu of fractional shares, which we expect will result in Vistra Energy's stockholders and Dynegy's stockholders owning approximately 79% and 21%, respectively, of the combined company. Dynegy stock options and equity-based awards outstanding immediately prior to the Effective Time will generally automatically convert upon completion of the Merger into stock options and equity-based awards, respectively, with respect to Vistra Energy's common stock, after giving effect to the Exchange Ratio.

The Merger Agreement also provides that, upon the closing of the Merger, the board of directors of the combined company will be comprised of 11 members, consisting of (a) the eight current directors of Vistra Energy and (b) three of Dynegy's current directors, of whom one will be a Class I director, one will be a Class II director and one will be a Class III director, unless the closing of the Merger occurs after the date of Vistra Energy's 2018 Annual Meeting of Stockholders, in which case one will be a Class I director and two will be Class II directors.

Completion of the Merger is subject to various customary conditions, including, among others, (a) approval by Vistra Energy's stockholders of the issuance of Vistra Energy's common stock in the Merger, (b) adoption of the Merger Agreement by Vistra Energy's stockholders and Dynegy's stockholders, (c) receipt of all requisite regulatory approvals, which includes approvals of the FERC, the PUCT, the Federal Communications Commission and the New York Public Service Commission, and the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, (HSR Waiting Period) and (d) the approval of the listing of shares to be issued on the NYSE. Each party's obligation to consummate the Merger is also subject to certain additional customary conditions, including (i) subject to certain exceptions, the accuracy of the representations and warranties of the other party, (ii) performance in all material respects by the other party of its obligations under the Merger Agreement and (iii) the receipt by such party of an opinion from its counsel to the effect that the Merger will qualify as a tax-free reorganization within the meaning of the Code. The HSR Waiting Period expired on February 5, 2018.

The Merger Agreement contains customary representations, warranties and covenants of Vistra Energy and Dynegy, including, among others, covenants (a) to conduct their respective businesses in the ordinary course during the interim period between the execution of the Merger Agreement and completion of the Merger, (b) not to take certain actions during the interim period except with the consent of the other party, (c) that Vistra Energy and Dynegy will convene and hold meetings of their respective stockholders to obtain the required stockholder approvals, and (d) that the parties use their respective reasonable best efforts to take all actions necessary to obtain all governmental and regulatory approvals and consents (except that Vistra Energy shall not be required, and Dynegy shall not be permitted, to take any action that constitutes or would reasonably be expected to have certain specified burdensome effects). Each of Vistra Energy and Dynegy is also subject to restrictions on its ability to solicit alternative acquisition proposals and to provide information to, and engage in discussion with, third parties regarding such proposals, except under limited circumstances to permit Vistra Energy's and Dynegy's boards of directors to comply with their respective fiduciary duties.

The Merger Agreement contains certain termination rights for both Vistra Energy and Dynegy, including in specified circumstances in connection with an alternative acquisition proposal that has been determined to be a superior offer. Upon termination of the Merger Agreement, under specified circumstances (a) for a failure by Vistra Energy to obtain certain requisite regulatory approvals, Vistra Energy may be required to pay Dynegy a termination fee of $100 million, (b) in connection with a superior offer, acquisition proposal or unforeseeable material intervening event, Vistra Energy may be required to pay a termination fee to Dynegy of $100 million, and (c) in connection with a superior offer, acquisition proposal or an unforeseeable material intervening event, Dynegy may be required to pay to Vistra Energy a termination fee of $87 million. In addition, if the Merger Agreement is terminated (i) because Vistra Energy's stockholders do not approve the issuance of Vistra Energy's common stock in the Merger or do not adopt the Merger Agreement, then Vistra Energy will be obligated to reimburse Dynegy for its reasonable out-of-pocket fees and expenses incurred in connection with the Merger Agreement, or (ii) because Dynegy's stockholders do not adopt the Merger Agreement, then Dynegy will reimburse Vistra Energy for its reasonable out-of-pocket fees and expenses incurred in connection with the Merger Agreement, each of which is subject to a cap of $22 million. Such expense reimbursement may be deducted from the foregoing termination fees, if ultimately payable.

The Merger is subject to certain risks and uncertainties, and there can be no assurance that we will be able to complete the Merger on the expected timeline or at all.

*Merger Support Agreements* — Concurrently with the execution of the Merger Agreement, certain stockholders of Vistra Energy, including affiliates of Apollo Management Holdings L.P. (collectively, the Apollo Entities), affiliates of Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P. (collectively, the Brookfield Entities) and certain affiliates of Oaktree Capital Management, L.P. (Oaktree), such agreements representing in the aggregate approximately 34% of the shares of Vistra Energy's common stock that will be entitled to vote on the Merger, and certain stockholders of Dynegy, including Terawatt Holdings, LP, an affiliate of certain affiliated investment funds of Energy Capital Partners III, LLC (Terawatt) and certain affiliates of Oaktree, such agreements representing in the aggregate approximately 21% of the shares of Dynegy's common stock that will be entitled to vote on the Merger, have entered into the Merger Support Agreements, pursuant to which each such stockholder agreed to vote their shares of common stock of Vistra Energy or Dynegy, as applicable, to adopt the Merger Agreement, and in the case of stockholders of Vistra Energy, approve the stock issuance. The Merger Support Agreements will automatically terminate upon a change of recommendation by the applicable board of directors or the termination of the Merger Agreement in accordance with its terms.

The foregoing description of the Merger Support Agreements does not purport to be complete and is qualified in its entirety by reference to that certain Merger Support Agreement, dated as of October 29, 2017, by and among Dynegy and the Apollo Entities, the Brookfield Entities and certain affiliates of Oaktree (filed as Exhibit 10.1 to Dynegy Inc.'s Current Report on Form 8-K filed on October 30, 2017), the Merger Support Agreement entered into between Vistra Energy and Terawatt (filed as Exhibit 10.1 to our Current Report on Form 8-K filed on October 31, 2017) and the Merger Support Agreement entered into between Vistra Energy and certain affiliates of Oaktree (filed as Exhibit 10.2 to our Current Report on Form 8-K filed on October 31, 2017).

*Litigation Related to the Merger* — In January 2018, a purported Dynegy stockholder filed a putative class action lawsuit in the U.S. District Court for the Southern Division of Texas, Houston Division, alleging that Dynegy, each member of the Dynegy board of directors and Vistra Energy violated federal securities laws by filing a Form S-4 Registration Statement in connection with the Merger that omits purportedly material information. The lawsuit seeks to enjoin the Merger and to have Dynegy and Vistra Energy issue an amended Form S-4 or, alternatively, damages if the Merger closes without an amended Form S-4 having been filed. Two other related lawsuits were also filed but neither of those named Vistra Energy. In February 2018, Vistra Energy and Dynegy filed supplemental disclosures to the Registration Statement and the plaintiffs agreed to forego any further effort to enjoin the Merger, dismiss the individual claims with prejudice, and dismiss without prejudice claims of the putative class following the stockholder vote scheduled for March 2, 2018.

***Environmental Regulations and Related Considerations***

We are subject to extensive environmental regulation by governmental authorities, including the EPA and the TCEQ. The EPA has recently finalized or proposed several regulatory actions establishing new requirements for control of certain emissions from sources, including electricity generation facilities. See Item 1A. *Risk Factors* for additional discussion of risks posed to us regarding regulatory requirements. See Note 13 to the Financial Statements for a discussion of litigation related to EPA reviews.

*Greenhouse Gas Emissions*

In August 2015, the EPA finalized rules to address greenhouse gas (GHG) emissions from new, modified and reconstructed and existing electricity generation units, referred to as the Clean Power Plan. The rule for existing facilities would establish state-specific emissions rate goals to reduce nationwide $CO_2$ emissions related to affected units by over 30% from 2012 emission levels by 2030. A number of parties, including Luminant, filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) for the rule for new, modified and reconstructed plants. In addition, a number of petitions for review of the rule for existing plants were filed in the D.C. Circuit Court by various parties and groups, including challenges from twenty-seven different states opposed to the rule as well as those from, among others, certain power generating companies, various business groups and some labor unions. Luminant also filed its own petition for review. In January 2016, a coalition of states, industry (including Luminant) and other parties filed applications with the U.S. Supreme Court (Supreme Court) asking that the Supreme Court stay the rule while the D.C. Circuit Court reviews the legality of the rule for existing plants. In February 2016, the Supreme Court stayed the rule pending the conclusion of legal challenges on the rule before the D.C. Circuit Court and until the Supreme Court disposes of any subsequent petition for review. Oral argument on the merits of the legal challenges to the rule was heard in September 2016 before the entire D.C. Circuit Court.

In March 2017, President Trump issued an Executive Order entitled *Promoting Energy Independence and Economic Growth* (Order). The Order covers a number of matters, including the Clean Power Plan. Among other provisions, the Order directs the EPA to review the Clean Power Plan and, if appropriate, suspend, revise or rescind the rules on existing and new, modified and reconstructed generating units. In April 2017, in accordance with the Order, the EPA published its intent to review the Clean Power Plan. In addition, the Department of Justice has filed motions seeking to abate those cases until the EPA concludes its review of the rules, including any new rulemaking that results from that review. In April 2017, the D.C. Circuit Court issued orders holding the cases in abeyance for 60 days and directing the EPA to provide status reports at 30-day intervals. The D.C. Circuit Court further ordered that all parties file supplemental briefs in May 2017 on whether the cases should be remanded to the EPA rather than held in abeyance. The D.C. Circuit Court entered additional 60-day abeyances in August 2017 and November 2017. The latest 60-day abeyance expired in January 2018, and the D.C. Circuit Court has yet to take further action on the EPA's request to continue the abeyance. In October 2017, the EPA issued a proposed rule that would repeal the Clean Power Plan. The proposed repeal focuses on what the EPA believes to be the unlawful nature of the Clean Power Plan and asks for public comment on the EPA's interpretations of its authority under the Clean Air Act. We currently plan to submit comments in response to the proposed repeal by April 2018. In December 2017, the EPA published an advance notice of proposed rulemaking (ANPR) soliciting information from the public as the EPA considers proposing a future rule. We currently plan on submitting comments by the February 2018 deadline. While we cannot predict the outcome of these rulemakings and related legal proceedings, or estimate a range of reasonably probable costs, if the rules are ultimately implemented or upheld as they were issued, they could have a material impact on our results of operations, liquidity or financial condition.

*Cross-State Air Pollution Rule (CSAPR)*

In July 2011, the EPA issued the CSAPR, compliance with which would have required significant additional reductions of sulfur dioxide ($SO_2$) and nitrogen oxide (NOx) emissions from our fossil fueled generation units. In February 2012, the EPA released a final rule (Final Revisions) and a proposed rule revising certain aspects of the CSAPR, including increases in the emissions budgets for Texas and our generation assets as compared to the July 2011 version of the rule. In June 2012, the EPA finalized the proposed rule (Second Revised Rule).

The CSAPR became effective January 1, 2015. In July 2015, following a remand of the case from the Supreme Court to consider further legal challenges, the D.C. Circuit Court ruled in favor of Luminant and other petitioners, holding that the CSAPR emissions budgets over-controlled Texas and other states. The D.C. Circuit Court remanded those states' budgets to the EPA for prompt reconsideration. While Luminant planned to participate in the EPA's reconsideration process to develop increased budgets for the 1997 ozone standard that do not over-control Texas, the EPA instead responded to the remand by proposing a new rulemaking that created new $NO_X$ ozone season budgets for the 2008 ozone standard without addressing the over-controlling budgets for the 1997 standard. Comments on the EPA's proposal were submitted by Luminant in February 2016. In August 2016, the EPA disapproved certain aspects of Texas's infrastructure State Implementation Plan (SIP) for the 2008 ozone National Ambient Air Quality Standard and imposed a Federal Implementation Plan (FIP) in its place in October 2016. Texas filed a petition in the Fifth Circuit Court challenging the SIP disapproval and Luminant intervened in support of Texas's challenge. The parties moved to stay the case and the court responded by dismissing the petition with the right to reinstate as provided in the Fifth Circuit Court's rules. The State of Texas and Luminant have also both filed challenges in the D.C. Circuit Court challenging the EPA's FIP and those cases are currently pending before that court. With respect to Texas's $SO_2$ emission budgets, in June 2016, the EPA issued a memorandum describing the EPA's proposed approach for responding to the D.C. Circuit Court's remand for reconsideration of the CSAPR $SO_2$ emission budgets for Texas and three other states that had been remanded to the EPA by the D.C. Circuit Court. In the memorandum, the EPA stated that those four states could either voluntarily participate in the CSAPR by submitting a SIP revision adopting the $SO_2$ budgets that had been previously held invalid by the D.C. Circuit Court and the current annual $NO_X$ budgets or, if the state chooses not to participate in the CSAPR, the EPA could withdraw the CSAPR FIP by the fall of 2016 for those states and address any interstate transport and regional haze obligations on a state-by-state basis. Texas has not indicated that it intends to adopt the over-controlling budgets and, in November 2016, the EPA proposed to withdraw the CSAPR FIP addressing $SO_2$ and NOx for Texas. In September 2017, the EPA finalized its proposal to remove Texas from the annual CSAPR programs. The Sierra Club and the National Parks Conservation Association filed a petition for review in the D.C. Circuit Court challenging that final rule. Luminant intervened on behalf of the EPA. As a result of the EPA's action, Texas electric generating units are no longer subject to the CSAPR annual $SO_2$ and $NO_X$ limits, but remain subject to the CSAPR's ozone season $NO_X$ requirements. While we cannot predict the outcome of future proceedings related to the CSAPR, including the EPA's recent actions concerning the CSAPR annual emissions budgets for affected states participating in the CSAPR program, based upon our current operating plans, including the recent retirements of our Monticello, Big Brown and Sandow 4 plants (see Note 4 to the Financial Statements), we do not believe that the CSAPR itself will cause any material operational, financial or compliance issues to our business or require us to incur any material compliance costs.

*Regional Haze — Reasonable Progress and Long-Term Strategies*

The Regional Haze Program of the CAA establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I federal areas, like national parks, which impairment results from man-made pollution." There are two components to the Regional Haze Program. First, states must establish goals for reasonable progress for Class I federal areas within the state and establish long-term strategies to reach those goals and to assist Class I federal areas in neighboring states to achieve reasonable progress set by those states towards a goal of natural visibility by 2064. In February 2009, the TCEQ submitted a SIP concerning regional haze (Regional Haze SIP) to the EPA. In December 2011, the EPA proposed a limited disapproval of the Regional Haze SIP due to its reliance on the Clean Air Interstate Rule (CAIR) instead of the EPA's replacement CSAPR program that the EPA finalized in July 2011. The EPA finalized the limited disapproval of Texas's Regional Haze SIP in June 2012. In August 2012, Luminant filed a petition for review in the Fifth Circuit Court challenging the EPA's limited disapproval of the Regional Haze SIP on the grounds that the CAIR continued in effect pending the D.C. Circuit Court's decision in the CSAPR litigation. In August 2012, Luminant filed a motion to intervene in a case filed by industry groups and other states and private parties in the D.C. Circuit Court challenging the EPA's limited disapproval and issuance of a FIP regarding the regional haze best available retrofit technology (BART) program. The Fifth Circuit Court case has since been transferred to the D.C. Circuit Court and consolidated with other pending BART program regional haze appeals. Briefing in the D.C. Circuit Court was completed in March 2017, and oral argument was held in November 2017.

In May 2014, the EPA issued requests for information under Section 114 of the CAA to Luminant and other generators in Texas related to the reasonable progress program. After releasing a proposed rule in November 2014 and receiving comments from a number of parties, including Luminant and the State of Texas in April 2015, the EPA issued a final rule in January 2016 approving in part and disapproving in part Texas' SIP for Regional Haze and issuing a FIP for Regional Haze. In the rule, the EPA asserts that the Texas SIP does not show reasonable progress in improving visibility for two areas in Texas and that its long-term strategy fails to make emission reductions needed to achieve reasonable progress in improving visibility in the Wichita Mountains of Oklahoma. The EPA's emission limits in the FIP assume additional control equipment for specific lignite/coal-fueled generation units across Texas, including new flue gas desulfurization systems (scrubbers) at seven electricity generating units and upgrades to existing scrubbers at seven generation units. Specifically, for Luminant, the EPA's FIP is based on new scrubbers at Big Brown Units 1 and 2 and Monticello Units 1 and 2 and scrubber upgrades at Martin Lake Units 1, 2 and 3, Monticello Unit 3 and Sandow Unit 4. Under the terms of the rule, subject to the legal proceedings described in the following paragraph, the scrubber upgrades would be required by February 2019, and the new scrubbers would be required by February 2021.

In March 2016, Luminant and a number of other parties, including the State of Texas, filed petitions for review in the Fifth Circuit Court challenging the FIP's Texas requirements. Luminant and other parties also filed motions to stay the FIP while the court reviews the legality of the EPA's action. In July 2016, the Fifth Circuit Court denied the EPA's motion to dismiss Luminant's challenge to the FIP and denied the EPA's motion to transfer the challenges Luminant, the other industry petitioners and the State of Texas filed to the D.C. Circuit Court. In addition, the Fifth Circuit Court granted the motions to stay filed by Luminant, the other industry petitioners and the State of Texas pending final review of the petitions for review. The case was abated until the end of November 2016 in order to allow the parties to pursue settlement discussions. Settlement discussions were unsuccessful, and in December 2016 the EPA filed a motion seeking a voluntary remand of the rule back to the EPA for further consideration of Luminant's pending request for administrative reconsideration. Luminant and some of the other petitioners filed a response opposing the EPA's motion to remand and filed a cross motion for vacatur of the rule in December 2016. In March 2017, the Fifth Circuit Court remanded the rule back to the EPA for reconsideration in light of the Court's prior determination that we and the other petitioners demonstrated a substantial likelihood that the EPA exceeded its statutory authority and acted arbitrarily and capriciously, but the Court denied all of the other pending motions. The stay of the rule (and the emission control requirements) remains in effect. In addition, the Fifth Circuit Court denied the EPA's motion to lift the stay as to parts of the rule implicated in the EPA's subsequent BART proposal and the Court is retaining jurisdiction of the case and requiring the EPA to file status reports on its reconsideration every 60 days. The recent retirements of our Monticello, Big Brown and Sandow 4 plants should have a favorable impact on this rulemaking and litigation. While we cannot predict the outcome of the rulemaking and legal proceedings, or estimate a range of reasonably possible costs, the result may have a material impact on our results of operations, liquidity or financial condition.

*Regional Haze — Best Available Retrofit Technology*

The second part of the Regional Haze Program subjects certain electricity generation units built between 1962 and 1977, to BART standards designed to improve visibility if such units cause or contribute to impairment of visibility in a federal class I area. BART reductions of $SO_2$ and $NO_X$ are required either on a unit-by-unit basis or are deemed satisfied by state participation in an EPA-approved regional trading program such as the CSAPR or other approved alternative program. In response to a lawsuit by environmental groups, the D.C. Circuit Court issued a consent decree in March 2012 that required the EPA to propose a decision on the Regional Haze SIP by May 2012 and finalize that decision by November 2012. The consent decree requires a FIP for any provisions that the EPA disapproves. The D.C. Circuit Court has amended the consent decree several times to extend the dates for the EPA to propose and finalize a decision on the Regional Haze SIP. The consent decree was modified in December 2015 to extend the deadline for the EPA to finalize action on the determination and adoption of requirements for BART for electricity generation. Under the amended consent decree, the EPA had until December 2016 to propose, and had until September 2017 to finalize, either approval of the state plan or a FIP for BART for Texas electricity generation sources if the EPA determines that BART requirements have not been met. The EPA issued a proposed BART FIP for Texas in January 2017. The EPA's proposed emission limits assume additional control equipment for specific lignite/coal-fueled generation units across Texas, including new flue gas desulfurization systems (scrubbers) at 12 electric generation units and upgrades to existing scrubbers at four electric generation units. Specifically, for Luminant, the EPA's proposed emission limitations were based on new scrubbers at Big Brown Units 1 and 2 and Monticello Units 1 and 2 and scrubber upgrades at Martin Lake Units 1, 2 and 3 and Monticello Unit 3. Luminant evaluated the requirements and potential financial and operational impacts of the proposed rule, but new scrubbers at the Big Brown and Monticello units necessary to achieve the emission limits required by the FIP (if those limits are possible to attain), along with the existence of low wholesale power prices in ERCOT, would challenge the long-term economic viability of those units. Under the terms of the proposed rule, the scrubber upgrades would have been required within three years of the effective date of the final rule and the new scrubbers will be required within five years of the effective date of the final rule. We submitted comments on the proposed FIP in May 2017.

The EPA signed the final BART FIP for Texas in September 2017. The rule is a partial approval of Texas's 2009 SIP and a partial FIP. In response to comments on the proposed rule submitted to the EPA, for $SO_2$, the rule creates an intrastate Texas emission allowance trading program as a "BART alternative" that operates in a similar fashion to a CSAPR trading program. The program includes 39 generating units, including our Martin Lake, Big Brown, Monticello, Sandow 4, Stryker 2 and Graham 2 plants. Of the 39 units, 30 are BART-eligible, three are co-located with a BART-eligible unit and six units are included in the program based on a visibility impacts analysis by the EPA. The 39 units represent 89% of $SO_2$ emissions from Texas electric generating units in 2016 and 85% of all CSAPR $SO_2$ allowance allocations for Texas existing electric generating units. The compliance obligations in the program will start on January 1, 2019. The identified units will receive an annual allowance allocation that is equal to their most recent annual CSAPR $SO_2$ allocation. Luminant's units covered by the program are allocated 91,222 allowances annually. Under the rule, a unit that is listed that does not operate for two consecutive years starting after 2018 would no longer receive allowances after the fifth year of non-operation. We believe the recent retirements of our Monticello, Big Brown and Sandow 4 plants will enhance our ability to comply with this BART rule for $SO_2$. For $NO_X$, the rule adopts the CSAPR's ozone program as BART and for particulate matter, the rule approves Texas's SIP that determines that no electric generating units are subject to BART for particulate matter. The National Parks Conservation Association, the Sierra Club and the Environmental Defense Fund filed a petition challenging the rule in the Fifth Circuit Court as well as a petition for reconsideration filed with the EPA. Additionally, the National Parks Conservation Association, the Sierra Club, the Environmental Defense Fund and other environmental groups filed a motion in the D.C. Circuit Court in October 2017 to enforce the terms of the consent decree that was originally entered in 2012. The EPA filed a cross-motion to terminate the consent decree in October 2017. These motions remain pending before the D.C. Circuit Court. Luminant has intervened on behalf of the EPA in that action. While we cannot predict the outcome of the rulemaking and potential legal proceedings, we believe the rule, if ultimately implemented or upheld as issued, will not have a material impact on our results of operation, liquidity or financial condition.

*Intersection of the CSAPR and Regional Haze Programs*

Historically the EPA has considered compliance with a regional trading program, such as the CSAPR, as satisfying a state's obligations under the BART portion of the Regional Haze Program. However, in the reasonable progress FIP, the EPA diverged from this approach and did not treat Texas' compliance with the CSAPR as satisfying its obligations under the BART portion of the Regional Haze Program. The EPA concluded that it would not be appropriate to finalize that determination given the remand of the CSAPR budgets. As described above, the EPA has now removed Texas from the annual CSAPR trading programs for $SO_2$ and $NO_X$ and has issued a final BART FIP for Texas.

*Affirmative Defenses During Malfunctions*

In February 2013, in response to a petition for rulemaking filed by the Sierra Club, the EPA proposed a rule requiring certain states to replace SIP exemptions for excess emissions during malfunctions with an affirmative defense. Texas was not included in that original proposal since it already had an EPA-approved affirmative defense provision in its SIP that was found to be lawful by the Fifth Circuit Court in 2013. In 2014, as a result of a D.C. Circuit Court decision striking down an affirmative defense in another EPA rule, the EPA revised its 2013 proposal to extend the EPA's proposed findings of inadequacy to states that have affirmative defense provisions, including Texas. The EPA's revised proposal would require Texas to remove or replace its EPA-approved affirmative defense provisions for excess emissions during startup, shutdown and maintenance events. In May 2015, the EPA finalized the proposal. In June 2015, Luminant filed a petition for review in the Fifth Circuit Court challenging certain aspects of the EPA's final rule as they apply to the Texas SIP. The State of Texas and other parties have also filed similar petitions in the Fifth Circuit Court. In August 2015, the Fifth Circuit Court transferred the petitions that Luminant and other parties filed to the D.C. Circuit Court, and in October 2015 the petitions were consolidated with the pending petitions challenging the EPA's action in the D.C. Circuit Court. Briefing in the D.C. Circuit Court on the challenges was completed in October 2016 and oral argument was originally set for May 2017. However, in April 2017, the court granted the EPA's motion to continue oral argument and ordered that the case be held in abeyance with the EPA to provide status reports to the court on the EPA's review of the action at 90-day intervals. We cannot predict the timing or outcome of this proceeding, or estimate a range of reasonably possible costs, but implementation of the rule as finalized may have a material impact on our results of operations, liquidity or financial condition.

*$SO_2$ Designations for Texas*

In February 2016, the EPA notified Texas of the EPA's preliminary intention to designate nonattainment areas for counties surrounding our Big Brown, Monticello and Martin Lake generation plants based on modeling data submitted to the EPA by the Sierra Club. Such designation would potentially require the implementation of various controls or other requirements to demonstrate attainment. Luminant submitted comments challenging the use of modeling data rather than data from actual air quality monitoring equipment. In November 2016, the EPA finalized its proposed designations for Texas including finalizing the nonattainment designations for the areas referenced above. In doing so, the EPA ignored contradictory modeling that we submitted with our comments. The final designation mandates would be for Texas to begin the multi-year process to evaluate what potential emission controls or operational changes, if any, may be necessary to demonstrate attainment. In February 2017, the State of Texas and Luminant filed challenges to the nonattainment designations in the Fifth Circuit Court and protective petitions in the D.C. Circuit Court. In March 2017, the EPA filed a motion to transfer or dismiss our Fifth Circuit Court petition, and the State of Texas and Luminant filed an opposition to that motion. Briefing on that motion in the Fifth Circuit Court was completed in May 2017, and the Fifth Circuit Court held oral argument on that motion in July 2017. In August 2017, the Fifth Circuit Court denied the EPA's motion to transfer our challenge to the D.C. Circuit Court. In October 2017, the Fifth Circuit Court granted the EPA's motion to hold the case in abeyance in light of the EPA's representation that it intended to revisit the rule. In December 2017, the TCEQ submitted a petition for reconsideration to the EPA. In addition, with respect to Monticello and Big Brown, the retirement of those plants should favorably impact our legal challenge to the nonattainment designations in that the nonattainment designation for Freestone County and Titus County are based solely on the Sierra Club modeling of alleged $SO_2$ emissions from Big Brown and Monticello. We dispute the Sierra Club's modeling. Regardless, considering these retirements, the nonattainment designation for those counties are no longer supported. While we cannot predict the outcome of this matter, or estimate a range of reasonably possible costs, the result may have a material impact on our results of operations, liquidity or financial condition.

*Water*

The TCEQ and the EPA have jurisdiction over water discharges (including storm water) from facilities in Texas. We believe our facilities are presently in material compliance with applicable state and federal requirements relating to discharge of pollutants into water. We believe we hold all required waste water discharge permits from the TCEQ for facilities in operation and have applied for or obtained necessary permits for facilities under construction. We also believe we can satisfy the requirements necessary to obtain any required permits or renewals.

Diversion, impoundment and withdrawal of water for cooling and other purposes are subject to the jurisdiction of the TCEQ and the EPA. We believe we possess all necessary permits from the TCEQ for these activities at our current facilities. Clean Water Act Section 316(b) regulations pertaining to existing water intake structures at large generation facilities became effective in 2014. Although the rule does not mandate a certain control technology, it does require site-specific assessments of technology feasibility on a case-by-case basis at the state level. Luminant has received determinations that most of our cooling water lakes are closed-cycle recirculating systems.

*Radioactive Waste*

See Item 2. *Properties* for discussion of storage of used nuclear fuel.

*Solid Waste*

Treatment, storage and disposal of solid waste and hazardous waste are regulated at the state level under the Texas Solid Waste Disposal Act and at the federal level under the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act. The EPA has issued regulations under the Resource Conservation and Recovery Act of 1976 and the Toxic Substances Control Act, and the TCEQ has issued regulations under the Texas Solid Waste Disposal Act applicable to our facilities. We believe we are in material compliance with all applicable solid waste rules and regulations. In addition, we have registered solid waste disposal sites and have obtained or applied for permits where required by such regulations.

*Environmental Capital Expenditures*

Capital expenditures for our environmental projects totaled $14 million in 2017 and are expected to total approximately $17 million in 2018 for environmental control equipment to comply with regulatory requirements.

**Exhibit 99.2**

## Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion should be read together with the consolidated financial statements and the notes thereto included in Exhibit 99.3 attached to this Current Report on Form 8-K. All references to notes to our consolidated financial statements refer to the financial statements included in Exhibit 99.3 attached to this Current Report on Form 8-K. All references to our Annual Report on Form 10-K refer to our Form 10-K for the year ended December 31, 2017 which was filed with the Securities and Exchange Commission on February 26, 2018. The following discussion has been updated subsequent to the filing of the Form 10-K to reflect a change in reporting segments in the first quarter of 2018.

As described in Note 1 to the Financial Statements, Vistra Energy is considered a new reporting entity for accounting purposes as of the Effective Date, and its financial statements reflect the application of fresh start reporting. The financial statements of Vistra Energy (the Successor) for periods subsequent to the Effective Date are not comparable to the financial statements of TCEH (the Predecessor) for periods prior to the Effective Date, as those previous periods do not give effect to any adjustments to the carrying values of assets or amounts of liabilities that resulted from the Plan of Reorganization, and the related application of fresh start reporting, which includes accounting policies implemented by Vistra Energy that may differ from the Predecessor. See Note 6 to the Financial Statements for further discussion of fresh start reporting.

The following discussion and analysis of our financial condition and results of operations for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 should be read in conjunction with our consolidated financial statements and the notes to those statements. Results are impacted by the effects of fresh start reporting, the Bankruptcy Filing and the application of Financial Accounting Standards Board Accounting Standards Codification (ASC) 852, *Reorganizations*.

All dollar amounts in the tables in the following discussion and analysis are stated in millions of U.S. dollars unless otherwise indicated.

### *Business*

Vistra Energy is a holding company operating an integrated power business in Texas. Through our Luminant and TXU Energy subsidiaries, we are principally engaged in competitive electricity market activities including electricity generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity and related services to end users. Prior to the Effective Date, TCEH was a holding company for our subsidiaries, which were principally engaged in the same activities as they are today.

### *Operating Segments*

Subsequent to the Effective Date, Vistra Energy has three reportable segments: (i) our Wholesale Generation segment, consisting largely of Luminant, (ii) our Retail Electricity segment, consisting largely of TXU Energy, and (iii) our Asset Closure segment, consisting of financial results of retired plants and mines. Prior to the Effective Date, there were no reportable business segments for TCEH. See Note 20 to the Financial Statements for further information concerning reportable business segments.

### *Significant Activities and Events and Items Influencing Future Performance*

***Merger Agreement*** — On October 29, 2017, Vistra Energy and Dynegy Inc., a Delaware corporation (Dynegy), entered into an Agreement and Plan of Merger (the Merger Agreement). Upon the terms and subject to the conditions set forth in the Merger Agreement, which has been approved by the boards of directors of Vistra Energy and Dynegy, Dynegy will merge with and into Vistra Energy (the Merger), with Vistra Energy continuing as the surviving corporation.

Upon the closing of the Merger, each issued and outstanding share of Dynegy common stock, par value $0.01 per share, other than shares owned by Vistra Energy or its subsidiaries, held in treasury by Dynegy or held by a subsidiary of Dynegy, will automatically be converted into the right to receive the Exchange Ratio, except that cash will be paid in lieu of fractional shares, which we expect will result in Vistra Energy's stockholders and Dynegy's stockholders owning approximately 79% and 21%, respectively, of the combined company.

See Note 2 to the Financial Statements for a summary of the Merger Agreement and the related Merger Support Agreements. The Merger is subject to numerous uncertainties and risks more fully described in Item 1. *Risk Factors* of this Annual Report on Form 10-K.

***Retirement of Generation Plants*** — In October 2017, Luminant announced plans to retire three power plants with a total installed nameplate generation capacity of approximately 4,167 MW and two lignite mines. These power plants include the Monticello, Sandow 4, Sandow 5 and Big Brown generation units. Luminant decided to retire these units given they are projected to be uneconomic based on current market conditions and given the significant environmental costs associated with operating such units. In the case of the Sandow units, the decision also reflected the execution of a Settlement Agreement discussed below.

As part of the retirement process, Luminant filed notices with ERCOT, which triggered a reliability review regarding such proposed retirements. In October and November 2017, ERCOT determined the units were not needed for reliability. The Sandow and Monticello units were retired in January 2018, and the Big Brown units were retired in February 2018.

During the year ended December 31, 2017, we recorded charges of approximately $206 million related to the retirements, including employee related severance costs, noncash charges for writing off materials inventory and a contract intangible asset associated with the Big Brown plant and the acceleration of Luminant's mining reclamation obligations (see Note 21 to the Financial Statements). In addition, we will continue the ongoing reclamation work at the plants' mines.

*Termination and Settlement of Alcoa Contract* — In October 2017, subsidiaries of Vistra Energy (Vistra Parties) entered into a separation and settlement agreement (Settlement Agreement) with Alcoa Corporation and Alcoa USA Corp. (collectively, the Alcoa Parties). Pursuant to the Settlement Agreement, the Vistra Parties and the Alcoa Parties agreed to early termination of a series of agreements related to industrial operations near Rockdale, Texas, thereby ending their contractual relationship with respect to the power generation unit known as Sandow Unit 4 and the mine known as Three Oaks Mine. The terminated agreements were scheduled to terminate in 2038 absent the Settlement Agreement. Among other things, the Alcoa Parties made a cash payment to the Vistra Parties in the amount of approximately $238 million and transferred certain real property and related assets to the Vistra Parties, the Vistra Parties agreed to assume and be responsible for certain liabilities and asset retirement obligations related to Sandow Unit 4 (including certain related common facilities), the related mine and other property transferred from the Alcoa Parties to the Vistra Parties, and both parties released one another from any obligations and claims under the terminated agreements. The transactions under the Settlement Agreement are effective as of October 1, 2017.

In the three months ended December 31, 2017, we recorded a gain related to the impacts of the Settlement Agreement in our consolidated financial statements totaling $11 million, which included the receipt of the cash payment, the acquisition of real property and the incurrence of certain liabilities and asset retirement obligations, along with the elimination of a related electric supply contract intangible asset on our consolidated balance sheet (see Note 7 to the Financial Statements).

***CCGT Plant Acquisition*** — In July 2017, La Frontera Holdings, LLC (La Frontera), an indirect wholly owned subsidiary of Vistra Energy, entered into an asset purchase agreement with Odessa-Ector Power Partners, L.P., an indirect wholly owned subsidiary of Koch Ag & Energy Solutions, LLC (the Odessa Acquisition), to acquire a 1,054 MW CCGT natural gas fueled generation plant (and other related assets and liabilities) located in Odessa, Texas (the Odessa Facility). On August 1, 2017, the Odessa Acquisition closed and La Frontera acquired the Odessa Facility. La Frontera paid an aggregate purchase price of approximately $355 million, plus a five-year earn-out provision, to acquire the Odessa Facility. The purchase price was funded by cash on hand.

***Upton Solar Development*** — In May 2017, we acquired the rights to develop, construct and operate a utility scale solar photovoltaic power generation facility in Upton County, Texas. As part of this project, we entered a turnkey engineering, procurement and construction agreement to construct the approximately 180 MW facility. For the year ended December 31, 2017, we have spent approximately $190 million related to this project primarily for progress payments under the engineering, procurement and construction agreement and the acquisition of the development rights. We currently estimate that the facility will begin operations in the summer of 2018.

***Repricing of Vistra Operations Credit Facilities*** — In February, August and December 2017 and February 2018, certain pricing terms for the Vistra Operations Credit Facility were amended. Any amounts borrowed under the Revolving Credit Facility will bear interest based on applicable LIBOR rates plus 2.25%. Amounts borrowed under the Initial Term Loan B Facility and the Term Loan C Facility will bear interest based on applicable LIBOR rates, subject to a 0.75% floor, plus 2.50%. The Incremental Term Loan B Facility will bear interest based on applicable LIBOR rates plus 2.25%. In connection with a repricing amendment in December 2017, the Revolving Credit Facility letter of credit sub-facility was increased from $600 million to $715 million and the Term Loan C Facility was reduced from $650 million to $500 million. See Note 12 to the Financial Statements for details of the Vistra Operations Credit Facilities.

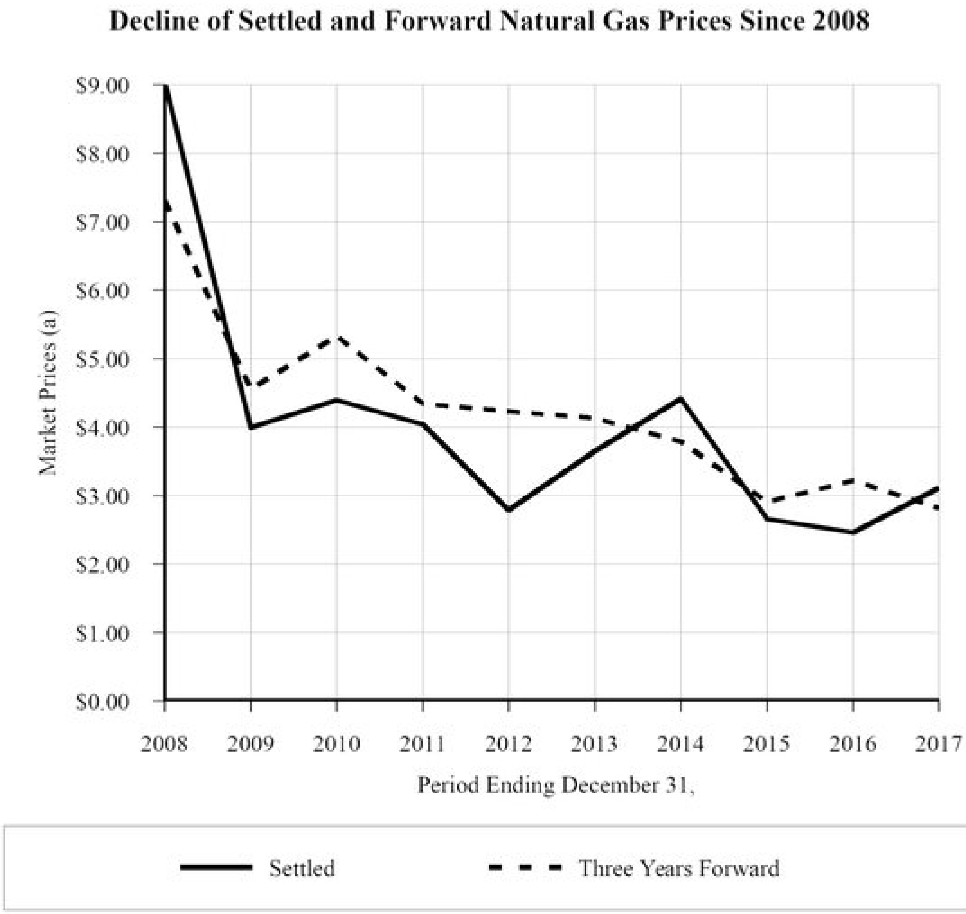
***Environmental Matters*** — See Note 13 to Financial Statements for a discussion of greenhouse gas emissions, the Cross-State Air Pollution Rule, regional haze, state implementation plan and other recent EPA actions as well as related litigation.

**Key Risks and Challenges**

Following is a discussion of key risks and challenges facing management and the initiatives currently underway to manage such challenges. These matters involve risks that could have a material effect on our results of operations, liquidity or financial condition.

*Natural Gas Price and Market Heat Rate Exposure*

The price of power in the ERCOT market is typically set by natural gas-fueled generation facilities, with wholesale prices generally tracking increases or decreases in the price of natural gas. In recent years, natural gas supply has outpaced demand primarily as a result of development and expansion of hydraulic fracturing in natural gas extraction; the supply/demand imbalance has resulted in historically low natural gas prices, and such prices have historically been volatile. The table below shows the general decline in forward natural gas prices over the last several years (amounts are per MMBtu.)




(a) Settled prices represent the average of NYMEX Henry Hub monthly settled prices of financial contracts for the year ending on the date presented. Forward prices represent the three-year average of NYMEX Henry Hub monthly forward prices at the date presented. Three-year forward prices are presented as such period is generally deemed to be a liquid period.

In contrast to our natural gas fueled generation facilities, changes in natural gas prices have no significant effect on the cost of generating power at our nuclear-, lignite- and coal-fueled facilities, which represent a substantial amount of our generation capacity. Consequently, all other factors being equal, these nuclear-, lignite- and coal-fueled generation assets increase or decrease in value as natural gas prices and market heat rates rise or fall, respectively, because of the effect on our operating margins from changes in wholesale electricity prices in ERCOT. A persistent decline in the price of natural gas, and the corresponding decline in the price of power in the ERCOT market, would likely have a material adverse effect on our results of operations, liquidity and financial condition, predominantly related to the production of power generation volumes in excess of the volumes utilized to service our retail customer load requirements.

The wholesale market price of electricity divided by the market price of natural gas represents the market heat rate. Market heat rate can be affected by a number of factors, including generation availability, mix of assets and the efficiency of the marginal supplier (generally natural gas-fueled generation facilities) in generating electricity. Our market heat rate exposure is impacted by changes in the availability of generation resources, such as additions and retirements of generation facilities, and mix of generation assets in ERCOT. For example, increasing renewable (wind and solar) generation capacity generally depresses market heat rates. Our heat rate exposure is also impacted by the potential economic backdown of our generation assets. Decreases in market heat rates decrease the value of our generation assets because lower market heat rates generally result in lower wholesale electricity prices, and vice versa. However, even though market heat rates have generally increased over the past several years, wholesale electricity prices have declined due to the greater effect of falling natural gas prices.

As a result of our exposure to the variability of natural gas prices and market heat rates in ERCOT, retail sales and hedging activities are critical to our operating results and maintaining consistent cash flow levels.

Our integrated power generation and retail electricity business provides us opportunities to hedge our generation position utilizing retail electricity markets as a sales channel. In addition, our approach to managing electricity price risk focuses on the following:

- employing disciplined, liquidity-efficient hedging and risk management strategies through physical and financial energy-related contracts intended to partially hedge gross margins;
- continuing focus on cost management to better withstand gross margin volatility;
- following a retail pricing strategy that appropriately reflects the value of our product offering to customers, the magnitude and costs of commodity price, liquidity risk and retail demand variability, and
- improving retail customer service to attract and retain high-value customers.

We have engaged in natural gas hedging activities to mitigate the risk of lower wholesale electricity prices that have corresponded to declines in natural gas prices. While current and forward natural gas prices are currently depressed, we continue to seek opportunities to manage our wholesale power price exposure through hedging activities, including forward wholesale and retail electricity sales.

Taking together forward wholesale, retail electricity sales and other retail customer considerations and all other hedging positions, at December 31, 2017, we had effectively hedged an estimated 90% and 22% of the natural gas price exposure related to our overall business for 2018 and 2019, respectively. Additionally, taking into consideration our overall heat rate exposure and related hedging positions at December 31, 2017, we had effectively hedged 83% and 42% of the heat rate exposure to our overall business for 2018 and 2019, respectively.

The following sensitivity table provides approximate estimates of the potential impact of movements in natural gas prices and market heat rates on realized pretax earnings (in millions) taking into account the hedge positions noted in the paragraph above for the periods presented. The estimates related to price sensitivity are based on our expected generation and retail positions, related hedges and forward prices as of December 31, 2017. The underlying hedge positions take into account the effects of the retirements of generation facilities discussed in Note 4 to the Financial Statements.

| | **Balance 2018 (a)** | **2019** |
|---|---|---|
| $0.50/MMBtu increase in natural gas price (b)(c) | $ ~25 | $ ~155 |
| $0.50/MMBtu decrease in natural gas price (b)(c) | $ ~(15) | $ ~(155) |
| 1.0/MMBtu/MWh increase in market heat rate (d) | $ ~60 | $ ~110 |
| 1.0/MMBtu/MWh decrease in market heat rate (d) | $ ~(55) | $ ~(100) |

(a) Balance of 2018 is from February 1, 2018 through December 31, 2018 for natural gas price sensitivities and January 1, 2018 through December 31, 2018 for market heat rate sensitivities.
(b) Assumes conversion of generation positions based on market heat rates and an estimate of natural gas generally being on the margin 70% to 90% of the time in the ERCOT market.
(c) Based on Houston Ship Channel natural gas prices at December 31, 2017.
(d) Based on ERCOT North Hub around-the-clock heat rates at December 31, 2017.

### *Competitive Retail Markets and Customer Retention*

Competitive retail activity in ERCOT has resulted in retail customer churn as customers switch retail electricity providers for various reasons. Based on numbers of meters, our total retail customer counts increased slightly in 2017 and declined approximately 1% in 2016 and less than 1% in 2015. Based upon December 31, 2017 results discussed below in *Results of Operations* , a 1% decline in retail customers would result in a decline in annual revenues of approximately $40 million. In responding to the competitive landscape in the ERCOT market, we have attempted to reduce overall customer losses by focusing on the following key initiatives:

- Maintaining competitive pricing initiatives on residential service plans;
- Actively competing for new customers in areas open to competition within ERCOT, while continuing to strive to enhance the experience of our existing customers; we are focused on continuing to implement initiatives that deliver world-class customer service and improve the overall customer experience;
- Establishing and leveraging our TXU Energy ™ brand in the sale of electricity to residential and commercial customers, as the most innovative retailer in the ERCOT market by continuing to develop tailored product offerings to meet customer needs, and
- Focusing market initiatives largely on programs targeted at retaining the existing highest-value customers and to recapturing customers who have switched REPs, including maintaining and continuously refining a disciplined contracting and pricing approach and economic segmentation of the business market to enhance targeted sales and marketing efforts and to more effectively deploy our direct-sales force; tactical programs we have initiated include improved customer service, aided by an enhanced customer management system, new product price/service offerings and a multichannel approach for the small business market.

### *Exposures Related to Nuclear Asset Outages*

Our nuclear assets are comprised of two generation units at the Comanche Peak facility, each with an installed nameplate generation capacity of 1,150 MW. As of February 26, 2018, these units represented approximately 17% of our total generation capacity. The nuclear generation units represent our lowest marginal cost source of electricity. Assuming both nuclear generation units experienced an outage at the same time, the unfavorable impact to pretax earnings is estimated (based upon forward electricity market prices for 2018 at December 31, 2017) to be approximately $1 million per day before consideration of any costs to repair the cause of such outages or receipt of any insurance proceeds. Also see discussion of nuclear facilities insurance in Note 13 to the Financial Statements.

The inherent complexities and related regulations associated with operating nuclear generation facilities result in environmental, regulatory and financial risks. The operation of nuclear generation facilities is subject to continuing review and regulation by the NRC, covering, among other things, operations, maintenance, emergency planning, security, and environmental and safety protection. The NRC may implement changes in regulations that result in increased capital or operating costs and may require extended outages, modify, suspend or revoke operating licenses and impose fines for failure to comply with its existing regulations and the provisions of the Atomic Energy Act. In addition, an unplanned outage at another nuclear generation facility could result in the NRC taking action to shut down our Comanche Peak units as a precautionary measure.

We participate in industry groups and with regulators to keep current on the latest developments in nuclear safety, operation and maintenance and on emerging threats and mitigating techniques. These groups include, but are not limited to, the NRC, the Institute of Nuclear Power Operations (INPO) and the Nuclear Energy Institute (NEI). We also apply the knowledge gained through our continuing investment in technology, processes and services to improve our operations and to detect, mitigate and protect our nuclear generation assets. Management continues to focus on the safe, reliable and efficient operations at the facility.

### *Cyber/Data Security and Infrastructure Protection Risk*

A breach of cyber/data security measures that impairs our information technology infrastructure could disrupt normal business operations and affect our ability to control our generation assets, access retail customer information and limit communication with third parties. Any loss of confidential or proprietary data through a breach could materially affect our reputation, including our TXU Energy ™ brand, expose the company to legal claims or impair our ability to execute on business strategies.

We participate in industry groups and with regulators to remain current on emerging threats and mitigating techniques. These groups include, but are not limited to, the U.S. Cyber Emergency Response Team, the National Electric Sector Cyber Security Organization, the NRC and NERC.

While the company has not experienced a cyber/data event causing any material operational, reputational or financial impact, we recognize the growing threat within the general market place and our industry, and are proactively making strategic investments in our perimeter and internal defenses, cyber/data security operations center and regulatory compliance activities. We also apply the knowledge gained through industry and government organizations to continuously improve our technology, processes and services to detect, mitigate and protect our cyber and data assets.

**Application of Critical Accounting Policies**

Our significant accounting policies are discussed in Note 1 to the Financial Statements. We follow accounting principles generally accepted in the U.S. Application of these accounting policies in the preparation of our consolidated financial statements requires management to make estimates and assumptions about future events that affect the reporting of assets and liabilities at the balance sheet dates and revenues and expenses during the periods covered. The following is a summary of certain critical accounting policies that are impacted by judgments and uncertainties and under which different amounts might be reported using different assumptions or estimation methodologies.

***Accounting in Reorganization and Fresh-Start Reporting***

The consolidated financial statements of our Predecessor reflect the application of ASC 852 . During the Chapter 11 Cases, the Debtors, including our Predecessor and its subsidiaries, operated their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. ASC 852 applies to entities that have filed a petition for bankruptcy under Chapter 11 of the Bankruptcy Code. The guidance requires that transactions and events directly associated with the reorganization be distinguished from the ongoing operations of the business. In addition, the guidance provides for changes in the accounting and presentation of liabilities. Expenses and income directly associated with the Chapter 11 Cases are reported separately in the statements of consolidated income (loss) as reorganization items. Reorganization items also include adjustments to reflect the carrying value of liabilities subject to compromise (LSTC) at their estimated allowed claim amounts, as such adjustments are determined. See Note 5 to the Financial Statements.

As of the Effective Date, Vistra Energy applied fresh-start reporting under the applicable provisions of ASC 852. Fresh-start reporting includes (1) distinguishing the consolidated financial statements of the entity that was previously in restructuring from the consolidated financial statements of the entity that emerges from restructuring, (2) assigning the reorganized value of the successor entity by measuring all assets and liabilities of the successor entity at fair value, and (3) selecting accounting policies for the successor entity. The effects from emerging from bankruptcy, including the extinguishment of liabilities, as well as the fresh start reporting adjustments are reported in the Predecessor's statement of consolidated income (loss). The consolidated financial statements of Vistra Energy for periods subsequent to the Effective Date are not comparable to the financial statements of our Predecessor for periods prior to the Effective Date, as those previous periods do not give effect to any adjustments to the carrying values of assets or amounts of liabilities, nor any differences in accounting policies that were a consequence of the Plan of Reorganization or the related application of fresh-start reporting. See Note 6 to the Financial Statements.

***Derivative Instruments and Mark-to-Market Accounting***

We enter into contracts for the purchase and sale of energy-related commodities, and also enter into other derivative instruments such as options, swaps, futures and forwards primarily to manage commodity price and interest rate risks. Under accounting standards related to derivative instruments and hedging activities, these instruments are subject to mark-to-market accounting, and the determination of market values for these instruments is based on numerous assumptions and estimation techniques.

Mark-to-market accounting recognizes changes in the fair value of derivative instruments in the financial statements as market prices change. Such changes in fair value are accounted for as unrealized mark-to-market gains and losses in net income with an offset to derivative assets and liabilities. The availability of quoted market prices in energy markets is dependent on the type of commodity ( *e.g.* , natural gas, electricity, etc.), time period specified and delivery point. In computing fair value for derivatives, each forward pricing curve is separated into liquid and illiquid periods. The liquid period varies by delivery point and commodity. Generally, the liquid period is supported by exchange markets, broker quotes and frequent trading activity. For illiquid periods, fair value is estimated based on forward price curves developed using modeling techniques that take into account available market information and other inputs that might not be readily observable in the market. We estimate fair value as described in Note 15 to the Financial Statements.

Accounting standards related to derivative instruments and hedging activities allow for normal purchase or sale elections and hedge accounting designations, which generally eliminate or defer the requirement for mark-to-market recognition in net income and thus reduce the volatility of net income that can result from fluctuations in fair values. Normal purchases and sales are contracts that provide for physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business and are not subject to mark-to-market accounting if the normal purchase or sale election is made. Vistra Energy does not have derivative instruments with hedge accounting designations.

We report derivative assets and liabilities in the consolidated balance sheets without taking into consideration netting arrangements that we have with counterparties. Margin deposits that contractually offset these assets and liabilities are reported separately in the consolidated balance sheets, with the exception of certain margin amounts related to changes in fair value on certain CME transactions that, beginning in January 2017, are legally characterized as settlement of derivative contracts rather than collateral.

See Note 16 to the Financial Statements for further discussion regarding derivative instruments.

***Accounting for Income Taxes***

EFH Corp. files a United States federal income tax return that includes the results of EFCH, EFIH, Oncor Holdings and, prior to the Effective Date, TCEH. EFH Corp. is the corporate parent of the EFH Corp. consolidated group, while each of EFIH, Oncor Holdings, EFCH and, prior to the effective date, TCEH was classified as a disregarded entity for United States federal income tax purposes. Pursuant to applicable United States Treasury regulations and published guidance of the IRS, corporations that are members of a consolidated group have joint and several liability for the taxes of such group. Subsequent to the Effective Date, the TCEH Debtor and the Contributed EFH Debtors are no longer included in the EFH Corp. consolidated group and are included in a consolidated group of which Vistra Energy is the corporate parent.

Prior to the Effective Date, EFH Corp. and certain of its subsidiaries (including EFCH, EFIH, and TCEH, but not including Oncor Holdings and Oncor) were parties to a Federal and State Income Tax Allocation Agreement, which provided, among other things, that any corporate member or disregarded entity in the EFH Corp. group was required to make payments to EFH Corp. in an amount calculated to approximate the amount of tax liability such entity would have owed if it filed a separate corporate tax return. Pursuant to the Plan of Reorganization, the TCEH Debtors and Contributed EFH Debtors rejected this agreement on the Effective Date. See Notes 5 and 8 to the Financial Statements for a discussion of the Tax Matters Agreement that was entered on the Effective Date between EFH Corp. and Vistra Energy. Additionally, since the date of the Settlement Agreement, no further cash payments among the Debtors were made in respect of federal income taxes. EFH Corp. has elected to continue to allocate federal income taxes among the entities that are parties to the Federal and State Income Tax Allocation Agreement. The Settlement Agreement did not alter the allocation and payment for state income taxes, which continued to be settled prior to the Effective Date.

Our income tax expense and related consolidated balance sheet amounts involve significant management estimates and judgments. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve estimates and judgments of the timing and probability of recognition of income and deductions by taxing authorities. In assessing the likelihood of realization of deferred tax assets, management considers estimates of the amount and character of future taxable income. Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, our forecasted financial condition and results of operations in future periods, as well as final review of filed tax returns by taxing authorities. Income tax returns are regularly subject to examination by applicable tax authorities. In management's opinion, the liability recorded pursuant to income tax accounting guidance related to uncertain tax positions reflects future taxes that may be owed as a result of any examination.

Our deferred tax assets were significantly impacted by the TCJA, which reduced the overall federal corporate rate from 35% to 21%. This rate change decreased our overall deferred tax asset balance by approximately $451 million.

See Notes 1 and 8 to the Financial Statements for discussion of income tax matters.

### *Accounting for Tax Receivable Agreement*

On the Effective Date, we entered into a tax receivable agreement (the TRA) with American Stock Transfer & Trust Company, LLC, as the transfer agent. Pursuant to the TRA, we issued beneficial interests in the rights to receive payments under the TRA (the TRA Rights) to the first lien creditors of our Predecessor to be held in escrow for the benefit of the first lien creditors of our Predecessor entitled to receive such TRA Rights under the Plan. As part of Emergence, Vistra Energy reflected the obligation associated with TRA Rights at fair value in the amount of $574 million related to these future payment obligations. As of December 31, 2017, the TRA obligation has been adjusted to $357 million. During the year ended December 31, 2017, we recorded reductions to the carrying value of the TRA obligation totaling approximately $295 million. The largest driver in the reduction to the TRA obligation carrying value primarily resulted from a change in the corporate tax rate from 35% to 21% related to tax reform legislation, which reduced the total expected undiscounted payments under the TRA from $2.1 billion to $1.2 billion. The TRA obligation value is the discounted amount of estimated payments to be made each year under the TRA, based on certain assumptions, including but not limited to:

- the amount of tax basis related to (i) the Lamar and Forney acquisition and (ii) step-up resulting from the PrefCo Preferred Stock Sale (which is estimated to be approximately $5.5 billion) and the allocation of such tax basis step-up among the assets subject thereto;
- the depreciable lives of the assets subject to such tax basis step-up, which generally is expected to be 15 years for most of such assets;
- a federal corporate income tax rate in all future years of 21%;
- the Company generally expects to generate sufficient taxable income to be able to utilize the deductions arising out of (i) the tax basis step up attributable to the PrefCo Preferred Stock Sale, (ii) the entire tax basis of the assets acquired as a result of the Lamar and Forney Acquisition, and (iii) tax benefits related to imputed interest deemed to be paid by us as a result of payments under the TRA in the tax year in which such deductions arise; and
- a discount rate of 15%, which represents our view of the rate that a market participant would use based on the risk associated with the uncertainty in the amount and timing of the cash flows, at the time of Emergence.

We recognize accretion expense over the life of the TRA Rights liability as the present value of the liability is accreted up over the life of the liability. This noncash accretion expense is reported in the statements of consolidated income (loss) as Impacts of Tax Receivable Agreement. Further, there may be significant changes, which may be material, to the estimate of the related liability due to various reasons including changes in corporate tax law, changes in estimates of future taxable income of Vistra Energy and its subsidiaries and other items. Changes in those estimates are recognized as adjustments to the related TRA Rights liability, with offsetting impacts recorded in the statements of consolidated income (loss) as Impacts of Tax Receivable Agreement. See Note 9 to the Financial Statements.

### *Asset Retirement Obligations (ARO)*

As part of fresh start reporting, new fair values were established for all AROs for the Successor. A liability is initially recorded at fair value for an asset retirement obligation associated with the legal obligation associated with law, regulatory, contractual or constructive retirement requirements of tangible long-lived assets in the period in which it is incurred if a fair value is reasonably estimable. Generally, changes in estimates related to ARO obligations are recorded as increases or decreases to the liability and related asset as information becomes available. Changes in estimates related to assets that have been retired or for which capitalized costs are not recoverable are reflected in income.

During the year ended December 31, 2017, we recorded additional ARO obligations totaling $112 million primarily reflecting the acceleration of ARO obligations due to the retirements of our Monticello, Sandow and Big Brown plants. In addition, we recorded additional ARO obligations totaling $62 million as part of acquiring certain real property through the Alcoa contract settlement.

See Note 21 to the Financial Statements for additional discussion of ARO obligations.

***Impairment of Goodwill and Other Long-Lived Assets***

We evaluate long-lived assets (including intangible assets with finite lives) for impairment, in accordance with accounting standards related to impairment or disposal of long-lived assets, whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. For our generation assets, possible indications include an expectation of continuing long-term declines in natural gas prices and/or market heat rates or an expectation that "more likely than not" a generation asset will be sold or otherwise disposed of significantly before the end of its estimated useful life. The determination of the existence of these and other indications of impairment involves judgments that are subjective in nature and may require the use of estimates in forecasting future results and cash flows related to an asset or group of assets. Further, the unique nature of our property, plant and equipment, which includes a fleet of generation assets with a diverse fuel mix and individual generation units that have varying production or output rates, requires the use of significant judgments in determining the existence of impairment indications and the grouping of assets for impairment testing. We generally utilize an income approach measurement to derive fair values for our long-lived generation assets. The income approach involves estimates of future performance that reflect assumptions regarding, among other things, forward natural gas and electricity prices, market heat rates, the effects of environmental rules, generation plant performance, forecasted capital expenditures and forecasted fuel prices. Any significant change to one or more of these factors can have a material impact on the fair value measurement of our long-lived assets. As a result of the decrease in forecasted wholesale electricity prices, potential effects from environmental regulations and changes to our Predecessor's operating plans in 2015 and 2014, our Predecessor evaluated the recoverability of its generation assets. See Note 4 to the Financial Statements for a discussion of the impairment charges related to certain of those assets. Additional material impairments related to these or other of our generation facilities may occur in the future if forward wholesale electricity prices in ERCOT decline or if additional environmental regulations increase the cost of producing electricity at our generation facilities.

Goodwill and intangible assets with indefinite useful lives, such as the intangible asset related to the TXU Energy ™ brand, are required to be tested for impairment at least annually (as of the Effective Date, we have selected October 1 as our annual test date) or whenever events or changes in circumstances indicate an impairment may exist, such as the indicators used to evaluate impairments to long-lived assets discussed above or declines in values of comparable public companies in our industry. Accounting guidance requires goodwill to be allocated to our reporting units, and at December 31, 2017 all goodwill was allocated to our Retail Electricity reporting unit. Goodwill impairment testing is performed at the reporting unit level. Under this goodwill impairment analysis, if at the assessment date, a reporting unit's carrying value exceeds its estimated fair value (enterprise value), the estimated enterprise value of the reporting unit is compared to the estimated fair values of the reporting unit's assets (including identifiable intangible assets) and liabilities at the assessment date, and the resultant implied goodwill amount is then compared to the recorded goodwill amount. Any excess of the recorded goodwill amount over the implied goodwill amount is written off as an impairment charge.

The determination of enterprise value involves a number of assumptions and estimates. We use a combination of fair value measurements to estimate enterprise values of our reporting units including: internal discounted cash flow analyses (income approach), and comparable publicly traded company values (market approach). The income approach involves estimates of future performance that reflect assumptions regarding, among other things, forward natural gas and electricity prices, market heat rates, the effects of environmental rules, generation plant performance, forecasted capital expenditures and retail sales volume trends, as well as determination of a terminal value. Another key variable in the income approach is the discount rate, or weighted average cost of capital, applied to the forecasted cash flows. The determination of the discount rate takes into consideration the capital structure, credit ratings and current debt yields of comparable publicly traded companies as well as an estimate of return on equity that reflects historical market returns and current market volatility for the industry. The market approach involves using trading multiples of EBITDA of those selected publicly traded companies to derive appropriate multiples to apply to the EBITDA of our reporting units. Critical judgments include the selection of publicly traded comparable companies and the weighting of the value metrics in developing the best estimate of enterprise value.

See Note 7 to the Financial Statements for additional discussion of the Predecessor's goodwill impairment charges.

## RESULTS OF OPERATIONS

***Vistra Energy Consolidated Financial Results — Year Ended December 31, 2017***

| | Successor | | | | |
|---|---|---|---|---|---|
| | Year Ended December 31, 2017 | | | | |
| | Wholesale Generation | Retail Electricity | Asset Closure | Eliminations / Corporate and Other | Vistra Energy Consolidated |
| Operating revenues | $ 1,794 | $ 4,058 | $ 964 | $ (1,386) | $ 5,430 |
| Fuel, purchased power costs and delivery fees | (981) | (2,733) | (607) | 1,386 | (2,935) |
| Operating costs | (578) | (14) | (380) | (1) | (973) |
| Depreciation and amortization (a) | (229) | (430) | (1) | (39) | (699) |
| Selling, general and administrative expenses | (124) | (420) | (19) | (37) | (600) |
| Impairment of long-lived assets | — | — | (25) | — | (25) |
| Operating income (loss) | (118) | 461 | (68) | (77) | 198 |
| Other income | 24 | 34 | 6 | (27) | 37 |
| Other deductions | (3) | — | (1) | (1) | (5) |
| Interest expense and related charges | (21) | — | — | (172) | (193) |
| Impacts of Tax Receivable Agreement | — | — | — | 213 | 213 |
| Income before income taxes | $ (118) | $ 495 | $ (63) | $ (64) | 250 |
| Income tax expense | | | | (504) | (504) |
| Net loss | | | | $ (568) | $ (254) |

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(a) Vistra Energy consolidated depreciation and amortization expense does not include $136 million of nuclear fuel amortization, reported as fuel costs, and intangible net assets and liabilities amortization, reported in various other line items including operating revenues and fuel and purchased power costs and delivery fees.

For the year ended December 31, 2017, consolidated operating income totaled $198 million and reflected strong operating performance in our Wholesale Generation and Retail Electricity segments despite an unplanned outage at one of our nuclear generation units and mild weather in both the summer and winter seasons. In addition, several strategic actions were announced during 2017, including the retirements of our Monticello, Sandow and Big Brown plants, the settlement of the Alcoa contract and the Merger Agreement with Dynegy. Operating income was reduced by $835 million in depreciation and amortization expense, $206 million in charges related to the plant retirement announcements and $116 million in unrealized mark-to-market losses on commodity risk management activity and interest rate swaps. Segment operating results were driven by:

- Our Wholesale Generation segment had strong operating performance from our generation fleet during the peak summer operating months, which was offset by unrealized mark-to-market losses on commodity risk management activities totaling $317 million for the period (including $154 million of unrealized losses on positions with the Retail Electricity segment), resulting in an operating loss of $118 million for the period. The unrealized losses were driven by the impacts of the reversal of previously recorded unrealized gains on settled positions and an increase in forward power prices, partially offset by unrealized gains due to a decrease in forward natural gas prices during the period. Operating loss also includes $319 million in depreciation and amortization expense, including nuclear fuel amortization. Additionally, operating loss includes a $74 million unfavorable impact due to an unplanned outage at one of our nuclear generation units that began in June 2017 ($57 million of lower earnings due to lost generation and $17 million of additional operating costs). The outage required repairs to the plant's steam turbine generator, a standard component in all power stations that is unrelated to Comanche Peak's nuclear reactor, which was not impacted by the outage. The unit returned to service in August 2017. Please see the discussion of Wholesale Generation below for further details.
- Our Retail Electricity segment had operating income of $461 million for the period, which was primarily driven by favorable profit margins and $154 million of unrealized gains in purchased power costs on positions with the Wholesale Generation segment, partially offset by $476 million in depreciation and amortization expense reflecting amortization expense related to retail customer relationship and retail contracts intangible assets. Please see the discussion of Retail Electricity below for further details.
- Our Asset Closure segment had an operating loss of $68 million for the period. Please see the Asset Closure segment financial results below for further details.

- Net operating expense related to Eliminations and Corporate and Other activities totaled $77 million and primarily reflected amortization of software and other technology-related assets (see Note 7 to the Financial Statements) and rent expense.

Interest expense and related charges totaled $193 million and included $213 million of interest expense incurred, partially offset by $29 million of unrealized mark-to-market gains on interest rate swaps (see Note 10 to the Financial Statements).

The Impacts of the Tax Receivable Agreement were income of $213 million, which includes a $295 million gain due to changes in the estimated amount and timing of TRA payments. See Note 9 to the Financial Statements for discussion of the impacts of the Tax Receivable Agreement obligation.

Income tax expense totaled $504 million. The effective tax rate of 201.6% was higher than the U.S. Federal statutory rate of 35% primarily due to a $451 million reduction of deferred tax assets related to the decrease in the corporate tax rate in the TCJA, partially offset by $80 million of tax impacts related to nondeductible TRA accretion. See Note 8 to the Financial Statements for reconciliation of this effective rate to the U.S. federal statutory rate.

Our total net loss of $254 million reflected the tax effects of the TCJA and the TRA obligation, as well as the items impacting operating income listed above.

***Vistra Energy Consolidated Financial Results — Period from October 3, 2016 through December 31, 2016***

| | Successor | | | | |
|---|---|---|---|---|---|
| | Period from October 3, 2016 through December 31, 2016 | | | | |
| | Wholesale Generation | Retail Electricity | Asset Closure | Eliminations / Corporate and Other | Vistra Energy Consolidated |
| Operating revenues | $ 212 | $ 912 | $ 238 | $ (171) | $ 1,191 |
| Fuel, purchased power costs and delivery fees | (214) | (515) | (162) | 171 | (720) |
| Operating costs | (151) | (3) | (54) | — | (208) |
| Depreciation and amortization (a) | (53) | (153) | — | (10) | (216) |
| Selling, general and administrative expenses | (65) | (130) | (6) | (7) | (208) |
| Operating income (loss) | (271) | 111 | 16 | (17) | (161) |
| Other income | 2 | 3 | 1 | 4 | 10 |
| Other deductions | — | — | — | — | — |
| Interest expense and related charges | 1 | — | — | (61) | (60) |
| Impacts of Tax Receivable Agreement | — | — | — | (22) | (22) |
| Income (loss) before income taxes | $ (268) | $ 114 | $ 17 | (96) | (233) |
| Income tax benefit | | | | 70 | 70 |
| Net loss | | | | $ (26) | $ (163) |

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(a) Vistra Energy consolidated depreciation and amortization expense does not include $69 million of nuclear fuel amortization, reported as fuel costs, and intangible net assets and liabilities amortization, reported in various other line items including operating revenues and fuel and purchased power costs and delivery fees.

Consolidated operating loss totaled $161 million for the period from October 3, 2016 through December 31, 2016. Results were driven by:

- Our Wholesale Generation segment had an operating loss of $271 million for the period, which was primarily driven by unrealized mark-to-market losses on commodity risk management activities totaling $273 million for the period (including $113 million of unrealized losses on positions with the Retail Electricity segment and $22 million of unrealized gains on hedging activities for fuel and purchased power costs). The unrealized losses were driven by increases in forward natural gas prices during the period. Please see the discussion of Wholesale Generation below for further details.
- Our Retail Electricity segment had an operating income of $111 million for the period, which was primarily driven by favorable profit margins, including $113 million of unrealized gains in purchased power costs on positions with the Wholesale Generation segment. Please see the discussion of Retail Electricity below for further details.
- Our Asset Closure segment had operating income of $16 million for the period. Please see the Asset Closure segment financial results below for further details.
- Net operating expense related to Eliminations and Corporate and Other activities totaled $17 million and primarily reflected $7 million in amortization of software and other technology-related assets (see Note 7 to the Financial Statements) and $4 million of post-Emergence restructuring fees.

Interest expense and related charges totaled $60 million and reflected $51 million of interest expense incurred and $11 million of unrealized mark-to-market losses on interest rate swaps (see Note 10 to the Financial Statements).

Impacts of the Tax Receivable Agreement were a loss of $22 million, which reflected accretion expense during the period. See Note 9 to the Financial Statements for discussion of the impacts of the Tax Receivable Agreement obligation.

Income tax benefit totaled $70 million. The effective tax rate was 30.0%. See Note 8 to the Financial Statements for reconciliation of this effective rate to the U.S. federal statutory rate.

***Operating Income***

We evaluate our segment performance using operating income as an earnings metric. We believe operating income is useful in evaluating our core business activities and is one of the metrics used by our chief operating decision maker and leadership to evaluate segment results. Operating income excludes interest income, interest expense and related charges, impacts of the Tax Receivables Agreement and income tax expense as these activities are managed at the corporate level.

***Operating Statistics — Year Ended December 31, 2017 and Period from October 3, 2016 through December 31, 2016***

| | Successor | |
|---|---|---|
| | **Year Ended December 31, 2017** | **Period from October 3, 2016 through December 31, 2016** |
| **Sales volumes (GWh):** | | |
| Retail electricity sales volumes: | | |
| Residential | 20,536 | 4,485 |
| Business markets | 18,496 | 4,430 |
| Total retail electricity sales volumes | 39,032 | 8,915 |
| Wholesale electricity sales volumes (a) | 48,578 | 13,806 |
| **Production volumes (GWh):** | | |
| Nuclear facilities | 16,921 | 5,373 |
| Lignite and coal facilities (Wholesale Generation segment) | 26,043 | 6,924 |
| Lignite and coal facilities (Asset Closure segment) | 25,392 | 6,730 |
| Natural gas facilities | 18,522 | 3,138 |
| **Capacity factors:** | | |
| Nuclear facilities | 84.0% | 105.7% |
| Lignite and coal facilities (Wholesale Generation segment) | 77.2% | 81.4% |
| Lignite and coal facilities (Asset Closure segment) | 69.6% | 73.1% |
| CCGT facilities | 69.3% | 47.0% |
| **Market pricing:** | | |
| Average ERCOT North power price ($/MWh) | $ 23.26 | $ 26.52 |
| **Weather (North Texas average) - percent of normal (b):** | | |
| Cooling degree days | 99.1% | 149.2% |
| Heating degree days | 72.1% | 79.5% |

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(a) Includes net amounts related to sales and purchases of balancing energy in the ERCOT real-time market.

(b) Weather data is obtained from Weatherbank, Inc., an independent company that collects and archives weather data from reporting stations of the National Oceanic and Atmospheric Administration (a federal agency under the U.S. Department of Commerce). Normal is defined as the average over the 10-year period from 2006 to 2015 for the year ended December 31, 2017 and 2001 to 2010 for the period from October 3, 2016 through December 31, 2016.

***Wholesale Generation Segment Financial Results — Year Ended December 31, 2017 and Period from October 3, 2016 through December 31, 2016***

For the year ended December 31, 2017, wholesale electricity revenues totaled $1.794 billion and included:

- $372 million in third-party wholesale electricity revenue, which included $523 million in electricity sales to third parties, including revenues from the Odessa power generation facility acquired in August 2017 (see Note 3 to the Financial Statements), and $151 million in unrealized losses from hedging activities reflecting the reversal of previously recorded unrealized gains on settled power positions and an increase in forward power prices, partially offset by unrealized gains due to a decrease in forward natural gas prices, and
- $1.385 billion in affiliated revenue with the Retail Electricity segment, which included $1.539 billion in sales for the period and $154 million in unrealized losses on hedging activities with affiliate positions reflecting an increase in forward power prices.

For the period from October 3, 2016 through December 31, 2016, wholesale electricity revenues totaled $212 million and included:

- $36 million in third-party wholesale electricity revenue, which included $218 million in electricity sales to third parties, partially offset by $182 million in unrealized losses from hedging activities reflecting an increase in forward natural gas prices and by the reversal of previously recorded unrealized gains on settled power positions, and
- $171 million in affiliated revenue with the Retail Electricity segment, which included $284 million in sales for the period, partially offset by $113 million in unrealized losses on hedging activities with affiliate positions reflecting an increase in forward commodity prices.

For the year ended December 31, 2017, wholesale electricity sales and operating costs include unfavorable impacts totaling $74 million due to an unplanned outage at one of our nuclear generation units that began in June 2017.

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Wholesale electricity sales | $ 523 | $ 218 |
| Unrealized net (losses) on hedging activities | (151) | (182) |
| Sales to affiliates | 1,539 | 284 |
| Unrealized net (losses) on hedging activities with affiliates | (154) | (113) |
| Other revenues | 37 | 5 |
| Total wholesale electricity revenues | $ 1,794 | $ 212 |

For the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, fuel, purchased power costs and delivery fees totaled $981 million and $214 million, respectively, and primarily reflected fuel and purchased power costs and ancillary and other costs. For the year ended December 31, 2017, fuel expense for our nuclear facilities was lower due to an unplanned outage at one of our units. For the year ended December 31, 2017, fuel expense for our natural gas facilities reflected incremental costs related to the Odessa Acquisition (see Note 3 to the Financial Statements). For the year ended December 31, 2017, fuel and purchased power costs also included $12 million in unrealized losses from hedging activities reflecting reversal of previously recorded unrealized gains on settled coal and diesel positions. For the period from October 3, 2016 through December 31, 2016, fuel and purchased power costs also included $22 million in unrealized gains from hedging activities reflecting gains on coal and diesel hedges due to increases in forward prices.

Operating costs totaled $578 million and $151 million for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, respectively, and reflected operations and maintenance expenses for power generation facilities and salaries and benefits for facilities personnel. For the year ended December 31, 2017, operating costs for our nuclear facilities were impacted by an unplanned outage at one of our units as well as refueling both units during the year, which occurs every three years. For the year ended December 31, 2017, operating costs for our natural gas facilities reflected the Odessa Acquisition.

For the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, depreciation and amortization expenses totaled $229 million and $53 million, respectively, and primarily reflected depreciation on power generation and mining property, plant and equipment.

For the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, SG&A totaled $124 million and $65 million, respectively, and primarily reflected functional group service costs allocated from Corporate and Other activities. SG&A costs reflect a workforce reduction in October 2016 that better aligned our cost structure, particularly as it relates to support functions within the business, to current market conditions.

***Retail Electricity Segment Financial Results — Year Ended December 31, 2017 and Period from October 3, 2016 through December 31, 2016***

For the year ended December 31, 2017, retail electricity revenues totaled $4.058 billion and included $3.916 billion related to 39,032 GWh in sales volumes. During the period, revenues were unfavorably impacted by mild weather in both the peak summer cooling period and the winter season at the beginning of the year as noted in the weather information included above in our *Operating Statistics* .

For the period from October 3, 2016 through December 31, 2016, retail electricity revenues totaled $912 million and included $907 million related to 8,915 GWh in sales volumes. Sales volumes for the period were evenly split between residential and business market customers.

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Retail electricity sales | $ 3,916 | $ 907 |
| Amortization income (expense) of identifiable intangible assets related to retail contracts (see Note 7 to the Financial Statements) | (46) | (36) |
| Other revenues | 188 | 41 |
| Total retail electricity revenues | $ 4,058 | $ 912 |

Purchased power costs, delivery fees and other costs totaled $2.733 billion and $515 million for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, respectively, and reflected the following:

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Purchases from affiliates | $ 1,539 | $ 284 |
| Unrealized net gains on hedging activities with affiliates | (154) | (113) |
| Delivery fees | 1,345 | 320 |
| Other costs | 3 | 24 |
| Total purchased power costs and delivery fees | $ 2,733 | $ 515 |

Depreciation and amortization expenses totaled $430 million and $153 million for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, respectively, and primarily reflected the impacts of amortization expense related to the retail customer relationship intangible asset established in fresh start reporting (see Note 7 to the Financial Statements).

SG&A totaled $420 million and $130 million for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, respectively, and reflected employee compensation and benefit costs (including functional group costs allocated from Corporate and Other), marketing and operation expenses and bad debt expense. SG&A costs reflect a workforce reduction in October 2016 that better aligned our cost structure, particularly as it relates to support functions within the business, to current market conditions. For the year ended December 31, 2017, SG&A reflects an increase in bad debt expense as a result of the estimated impact on collectability from customers affected by Hurricane Harvey.

***Asset Closure Segment Financial Results — Year Ended December 31, 2017 and Period from October 3, 2016 through December 31, 2016***

Results for the Asset Closure segment include the Monticello, Sandow and Big Brown plants that were retired in January and February 2018. For the year ended December 31, 2017, operating loss totaled $68 million related to production volumes of 25,392 GWh. Operating loss in 2017 includes a charge of $206 million related to the plant retirement announcements, including (i) $170 million of operating costs related to severance accruals, write-off of material and supplies inventory and changes to estimates and timing of asset retirement obligations and (ii) $25 million of impairments of long-lived assets related to the write-off of capitalized improvements of our Sandow 4 generation facility. For the period from October 3, 2016 through December 31, 2016, operating revenues totaled $16 million related to production volumes of 6,730 GWh.

***Predecessor Consolidated Financial Results — Period from January 1, 2016 through October 2, 2016 and the Year Ended December 31, 2015***

| | Predecessor | |
|---|---|---|
| | **Period from January 1, 2016 through October 2, 2016** | **Year Ended December 31, 2015** |
| Operating revenues | $ 3,973 | $ 5,370 |
| Fuel, purchased power costs and delivery fees | (2,082) | (2,692) |
| Net gain from commodity hedging and trading activities | 282 | 334 |
| Operating costs | (664) | (834) |
| Depreciation and amortization | (459) | (852) |
| Selling, general and administrative expenses | (482) | (676) |
| Impairment of goodwill | — | (2,200) |
| Impairment of long-lived assets | — | (2,541) |
| Operating income (loss) | 568 | (4,091) |
| Other income | 19 | 18 |
| Other deductions | (75) | (93) |
| Interest expense and related charges | (1,049) | (1,289) |
| Reorganization items | 22,121 | (101) |
| Income (loss) before income taxes | 21,584 | (5,556) |
| Income tax benefit | 1,267 | 879 |
| Net income (loss) | $ 22,851 | $ (4,677) |

*Predecessor Operating Statistics — Period from January 1, 2016 through October 2, 2016 and the Year Ended December 31, 2015*

| | Predecessor | |
|---|---|---|
| | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| **Operating revenues:** | | |
| Retail electricity revenues | $ 3,154 | $ 4,449 |
| Wholesale electricity revenues and other operating revenues (a)(b) | 819 | 921 |
| Total operating revenues | $ 3,973 | $ 5,370 |
| **Fuel, purchased power costs and delivery fees:** | | |
| Fuel for nuclear facilities | $ 92 | $ 146 |
| Fuel for lignite and coal facilities | 548 | 736 |
| Fuel for natural gas facilities and purchased power costs (a) | 310 | 252 |
| Other costs | 108 | 166 |
| Delivery fees | 1,024 | 1,392 |
| Total | $ 2,082 | $ 2,692 |
| **Sales volumes:** | | |
| Retail electricity sales volumes (GWh): | | |
| Residential | 16,619 | 21,923 |
| Business markets | 14,354 | 19,289 |
| Total retail electricity | 30,973 | 41,212 |
| Wholesale electricity sales volumes (b) | 25,563 | 23,533 |
| **Production volumes (GWh):** | | |
| Nuclear facilities | 15,005 | 19,954 |
| Lignite and coal facilities (c) | 31,865 | 41,817 |
| Natural gas facilities | 8,539 | 709 |
| **Capacity factors:** | | |
| Nuclear facilities | 99.2% | 99.0% |
| Lignite and coal facilities (c) | 60.5% | 59.5% |
| CCGT facilities | 65.2% | N/A |
| **Market pricing:** | | |
| Average ERCOT North power price ($/MWh) | $ 20.78 | $ 23.78 |
| **Weather (North Texas average) - percent of normal (d):** | | |
| Cooling degree days | 102.8% | 105.4% |
| Heating degree days | 81.9% | 103.8% |

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(a) Upon settlement, physical derivative commodity contracts that we mark-to-market in net income, such as certain electricity sales and purchase agreements and coal purchase contracts, wholesale electricity revenues and fuel and purchased power costs are reported at approximated market prices, as required by accounting rules, rather than contract price. The offsetting differences between contract and market prices are reported in net gain from commodity hedging and trading activities.

(b) Includes net amounts related to sales and purchases of balancing energy in the ERCOT real-time market.

(c) Includes the estimated effects of economic backdown (including seasonal operations) of lignite/coal-fueled units totaling 14,420 GWh and 19,900 GWh for the period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, respectively.

(d) Weather data is obtained from Weatherbank, Inc., an independent company that collects and archives weather data from reporting stations of the National Oceanic and Atmospheric Administration (a federal agency under the U.S. Department of Commerce). Normal is defined as the average over the 10-year period from 2000 to 2010.

***Predecessor Financial Results — Period from January 1, 2016 through October 2, 2016 and the Year Ended December 31, 2015***

For the period from January 1, 2016 through October 2, 2016, income before income taxes totaled $21.584 billion and included a $24.252 billion gain on reorganization adjustments and a $2.013 billion loss for the net impacts from the adoption of fresh start reporting (see Notes 5 and 6 to the Financial Statements). Results also reflected the effect of declining average electricity prices on operating revenues, $977 million in adequate protection interest expense paid/accrued on pre-petition debt and $116 million in reorganization items associated with the Chapter 11 Cases. For the year ended December 31, 2015, loss before income taxes totaled $5.556 billion and primarily reflected noncash impairments of certain long-lived assets totaling $2.541 billion and of goodwill totaling $2.2 billion.

Operating revenues totaled $3.973 billion and $5.370 billion for the period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, respectively.

- For the period from January 1, 2016 through October 2, 2016, retail electricity revenues totaled $3.154 billion and were negatively impacted by declining average prices and reduced volumes reflecting milder than normal weather in 2016. Wholesale revenues totaled $649 million and were positively impacted by increases in generation volumes (approximately 8,048 GWh) driven by the Lamar and Forney generation assets acquired in April 2016 (see Note 3 to the Financial Statements), partially offset by lower average wholesale electricity prices.

- For the year ended December 31, 2015, retail electricity revenues totaled $4.449 billion and were favorably impacted by increased sales volumes driven by increased business volumes, partially offset by lower average retail prices primarily for business market customers. Wholesale revenues totaled $680 million and were negatively impacted by decreases in generation volumes driven by increased economic backdown (including seasonal operations) at lignite and coal generation facilities driven by a decline in wholesale electricity prices.

Following is an analysis of amounts reported as net losses from commodity hedging and trading activities. Results are primarily related to natural gas and power hedging activity.

| | Predecessor | |
|---|---|---|
| | **Period from January 1, 2016 through October 2, 2016** | **Year Ended December 31, 2015** |
| Realized net gains | $ 320 | $ 217 |
| Unrealized net gains (losses) | (38) | 117 |
| Total | $ 282 | $ 334 |

For both periods presented, the negative impacts of declining average prices on wholesale operating revenues were partially offset by realized net gains reflecting settled gains on derivatives due to declining market prices. These gains were primarily related to natural gas positions.

For the period from January 1, 2016 through October 2, 2016, net unrealized losses were primarily impacted by reversals of previously recorded unrealized net gains on settled positions. For the year ended December 31, 2015, net unrealized gains were primarily impacted by the impact of declining natural gas prices on our Predecessor's hedging program.

Fuel, purchased power costs and delivery fees totaled $2.082 billion and $2.692 billion for the period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, respectively. For the period from January 1, 2016 through October 2, 2016, fuel, purchased power costs and delivery fees reflected the impact of declining electricity prices on purchased power costs during 2016, partially offset by incremental natural gas fuel costs associated with the Lamar and Forney Acquisition.

Operating costs totaled $664 million and $834 million for the period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, respectively, and primarily reflect maintenance expense for generation assets, including the scope and timing of maintenance costs at lignite/coal-fueled generation facilities. For the period from January 1, 2016 through October 2, 2016, operating costs were also impacted by incremental operation and maintenance costs associated with the Lamar and Forney Acquisition.

Depreciation and amortization expenses totaled $459 million and $852 million for the period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, respectively. primarily reflected depreciation on power generation and mining property, plant and equipment and amortization of identifiable intangible assets. For the period from January 1, 2016 through October 2, 2016, depreciation and amortization expenses were also impacted by incremental depreciation expense associated with the Lamar and Forney Acquisition.

SG&A expenses totaled $482 million and $676 million for the period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, respectively, and reflected administrative and general salaries, employee benefits, marketing costs related to retail electricity activity and other administrative costs.

For the period from January 1, 2016 through October 2, 2016, results also include $32 million of severance expense, primarily reported in fuel, purchased power costs and delivery fees and operating costs, associated with certain actions taken to reduce costs related to mining and lignite/coal generation operations.

For the period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, interest expense and related charges totaled $1.049 billion and $1.289 billion, respectively, and included adequate protection payments approved by the Bankruptcy Court for the benefit of TCEH secured creditors totaling $977 million and $1.233 billion, respectively, and interest expense on debtor-in-possession financing totaling $76 million and $63 million, respectively.

***Energy-Related Commodity Contracts and Mark-to-Market Activities***

The table below summarizes the changes in commodity contract assets and liabilities for the periods presented. The net change in these assets and liabilities, excluding "other activity" as described below, reflects $145 million and $166 million in unrealized net losses for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, respectively, and $38 million in unrealized net losses and $117 million in unrealized net gains for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, respectively, all arising from mark-to-market accounting for positions in the commodity contract portfolio.

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Commodity contract net asset at beginning of period | $ 64 | $ 181 | $ 271 | $ 180 |
| Settlements/termination of positions (a) | (207) | (95) | (232) | (263) |
| Changes in fair value of positions in the portfolio (b) | 62 | (71) | 194 | 380 |
| Other activity (c) | (15) | 49 | (35) | (26) |
| Commodity contract net asset (liability) at end of period | $ (96) | $ 64 | $ 198 | $ 271 |

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(a) Represents reversals of previously recognized unrealized gains and losses upon settlement/termination (offsets realized gains and losses recognized in the settlement period). The Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 includes reversal of $63 million and $90 million, respectively, of previously recorded unrealized gains related to Vistra Energy beginning balances. Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into, and settled, in the same month.

(b) Represents unrealized net gains (losses) recognized, reflecting the effect of changes in fair value. The Successor period for the year ended December 31, 2017 includes a $23 million inception gain related to long-term power derivatives. Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into, and settled, in the same month.

(c) Represents changes in fair value of positions due to receipt or payment of cash not reflected in unrealized gains or losses. Amounts are generally related to certain margin deposits classified as settlement for certain transactions executed on the CME as well as premiums related to options purchased or sold and the initial fair value of the earn-out provision related to the Odessa Acquisition (see Note 3 to the Financial Statements). The Predecessor period from January 1, 2016 through October 2, 2016 includes fair value of acquired commodity contracts as of the date of the Lamar and Forney Acquisition (see Note 3 to the Financial Statements).

***Maturity Table*** — The following table presents the net commodity contract liability arising from recognition of fair values at December 31, 2017, scheduled by the source of fair value and contractual settlement dates of the underlying positions.

| | Successor | | | | |
|---|---|---|---|---|---|
| | Maturity dates of unrealized commodity contract net liability at December 31, 2017 | | | | |
| **Source of fair value** | **Less than 1 year** | **1-3 years** | **4-5 years** | **Excess of 5 years** | **Total** |
| Prices actively quoted | $ 11 | $ (9) | $ — | $ — | $ 2 |
| Prices provided by other external sources | (12) | (33) | — | — | (45) |
| Prices based on models | (16) | (45) | (1) | 9 | (53) |
| Total | $ (17) | $ (87) | $ (1) | $ 9 | $ (96) |

## FINANCIAL CONDITION

### *Operating Cash Flows*

***Successor*** *— Year Ended December 31, 2017 —* Cash provided by operating activities totaled $1.386 billion in 2017 and was primarily driven by $1.168 billion of cash from operations, $238 million in proceeds from the Alcoa contract settlement and a $146 million net source of cash reflecting decreases in cash utilized in margin postings related to derivative contracts.

*Period from October 3, 2016 through December 31, 2016 —* Cash provided by operating activities totaled $81 million and was primarily driven by cash earnings from our business of approximately $251 million after taking into consideration depreciation and amortization and unrealized mark-to-market losses on derivatives, offset by a net use of cash of approximately $170 million in working capital primarily driven by cash utilized in margin postings related to derivative contracts.

*Depreciation and Amortization —* Depreciation and amortization expense reported as a reconciling adjustment in the statements of consolidated cash flows exceed the amount reported in the statements of consolidated income (loss) by $136 million and $69 million for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, respectively. The difference represented amortization of nuclear fuel, which is reported as fuel costs in the statements of consolidated income (loss) consistent with industry practice, and amortization of intangible net assets and liabilities that are reported in various other statements of consolidated income (loss) line items including operating revenues and fuel and purchased power costs and delivery fees.

***Predecessor*** *— Period from January 1, 2016 through October 2, 2016 —* Cash used in operating activities totaled $238 million and was primarily driven by cash used for margin deposit postings and other working capital utilization.

*Year Ended December 31, 2015 —* Cash provided by operating activities totaled $237 million in 2015 and was primarily driven by cash used for margin deposit postings and other working capital utilization.

### *Financing Cash Flows*

***Successor*** *— Year Ended December 31, 2017 —* Cash used in financing activities totaled $201 million in 2017 and reflected the repayment of debt, including the repayment of $150 million in principal under the Term Loan C Facility (see Note 12 to the Financial Statements).

*Period from October 3, 2016 through December 31, 2016 —* Cash provided by financing activities totaled $6 million and related to the net impacts of the Incremental Term Loan B borrowings and the Special Dividend paid to shareholders.

***Predecessor*** *— Period from January 1, 2016 through October 2, 2016 —* Cash provided by financing activities totaled $1.059 billion and primarily reflected $2.040 billion in net borrowings under the DIP Roll Facilities and the DIP Facility, including $870 million in net borrowings to fund the Lamar and Forney Acquisition (see Note 3 to the Financial Statements), and $69 million from the issuance of preferred stock, partially offset by $915 million in payments to extinguish claims under the Plan of Reorganization and $112 million in fees related to the issuance of the DIP Roll Facilities.

*Year Ended December 31, 2015 —* Cash used in financing activities totaled $30 million and reflected the repayments of certain debt principal and fees.

### *Investing Cash Flows*

***Successor*** *— Year Ended December 31, 2017 —* Cash used in investing activities totaled $727 million in 2017 and reflected payments of $355 million related to the Odessa Acquisition, Upton solar development expenditures totaling $190 million and capital expenditures (including nuclear fuel purchases) totaling $176 million. The Odessa Acquisition and the Upton solar development were funded using cash on hand.

Capital expenditures, including nuclear fuel, in the year ended December 31, 2017 totaled $176 million and consisted of:

- $74 million primarily for our generation operations;
- $14 million for environmental expenditures related to generation units;
- $62 million for nuclear fuel purchases, and
- $26 million for information technology and other corporate investments.

*Period from October 3, 2016 through December 31, 2016* — Cash used in investing activities totaled $93 million and was primarily driven by capital expenditures of $48 million and purchases of nuclear fuel of $41 million.

Capital expenditures, including nuclear fuel, in the period from October 3, 2016 through December 31, 2016 totaled $89 million and consisted of:

- $18 million primarily for our generation operations;
- $22 million for environmental expenditures related to generation units;
- $41 million for nuclear fuel purchases, and
- $8 million for information technology and other corporate investments.

***Predecessor*** — *Period from January 1, 2016 through October 2, 2016* — Cash used in investing activities totaled $1.420 billion. Cash used reflected payments of $1.343 billion related to the Lamar and Forney Acquisition net of cash acquired (see Note 3 to the Financial Statements) and capital expenditures (including nuclear fuel purchases) totaling $263 million, partially offset by a $233 million decrease in restricted cash used to backstop letters of credit.

Capital expenditures, including nuclear fuel, in the period from January 1, 2016 through October 2, 2016 totaled $263 million and consisted of:

- $171 million primarily for our generation operations;
- $40 million for environmental expenditures related to generation units;
- $33 million for nuclear fuel purchases, and
- $19 million for information technology and other corporate investments.

*Year Ended December 31, 2015* — Cash used in investing activities totaled $650 million and reflected capital expenditures (including nuclear fuel purchases) totaling $460 million and a $123 million increase in restricted cash largely for supporting letters of credit issued under the DIP Facility.

Capital expenditures, including nuclear fuel, in 2015 totaled $460 million and consisted of:

- $230 million primarily for our generation operations;
- $82 million for environmental expenditures related to generation units;
- $123 million for nuclear fuel purchases, and
- $25 million for information technology and other corporate investments.

***Debt Activity***

See Note 12 to the Financial Statements for details of the Vistra Operations Credit Facilities and other long-term debt.

***Available Liquidity***

The following table summarizes changes in available liquidity for the year ended December 31, 2017:

| | December 31, 2017 | December 31, 2016 | Change |
|---|---|---|---|
| Cash and cash equivalents (a) | $ 1,487 | $ 843 | $ 644 |
| Vistra Operations Credit Facilities — Revolving Credit Facility | 834 | 860 | (26) |
| Vistra Operations Credit Facilities — Term Loan C Facility (b) | 7 | 131 | (124) |
| Total liquidity | $ 2,328 | $ 1,834 | $ 494 |

(a) Cash and cash equivalents excludes $500 million and $650 million of restricted cash held for letter of credit support at December 31, 2017 and 2016, respectively (see Note 21 to the Financial Statements).
(b) The Term Loan C Facility is used for issuing letters of credit for general corporate purposes. Borrowings totaling $500 million and $650 million under this facility were held in collateral accounts at December 31, 2017 and 2016, respectively, and are reported as restricted cash in our consolidated balance sheets. The December 31, 2017 restricted cash balance represents borrowings under the Term Loan C Facility held in collateral accounts that support $493 million in letters of credit outstanding, leaving $7 million in available letter of credit capacity (see Note 12 to the Financial Statements).

The increase in available liquidity of $494 million in the year ended December 31, 2017 compared to December 31, 2016 was primarily driven by increased available cash from operations, partially offset by the repayment of $150 million in principal under the Term Loan C Facility and cash utilized in the Odessa Acquisition and our development of the Upton solar facility.

Based upon our current internal financial forecasts, we believe that we will have sufficient amounts available under the Vistra Operations Credit Facilities, plus cash generated from operations, to fund our anticipated cash requirements through at least the next 12 months.

***Capital Expenditures***

Estimated capital expenditures and nuclear fuel purchases for 2018 are expected to total approximately $396 million and include:

- $248 million for investments in generation and mining facilities, including approximately:
  - $231 million primarily for our generation operations and
  - $17 million for environmental expenditures,
- $118 million for nuclear fuel purchases, and
- $30 million for information technology and other corporate investments.

***Liquidity Effects of Commodity Hedging and Trading Activities***

We have entered into commodity hedging and trading transactions that require us to post collateral if the forward price of the underlying commodity moves such that the hedging or trading instrument we hold has declined in value. We use cash, letters of credit and other forms of credit support to satisfy such collateral posting obligations. See Note 12 to the Financial Statements for discussion of the Vistra Operations Credit Facilities.

Exchange cleared transactions typically require initial margin ( *i.e.* , the upfront cash and/or letter of credit posted to take into account the size and maturity of the positions and credit quality) in addition to variation margin ( *i.e.* , the daily cash margin posted to take into account changes in the value of the underlying commodity). The amount of initial margin required is generally defined by exchange rules. Clearing agents, however, typically have the right to request additional initial margin based on various factors, including market depth, volatility and credit quality, which may be in the form of cash, letters of credit, a guaranty or other forms as negotiated with the clearing agent. Cash collateral received from counterparties is either used for working capital and other business purposes, including reducing borrowings under credit facilities, or is required to be deposited in a separate account and restricted from being used for working capital and other corporate purposes. With respect to over-the-counter transactions, counterparties generally have the right to substitute letters of credit for such cash collateral. In such event, the cash collateral previously posted would be returned to such counterparties, which would reduce liquidity in the event the cash was not restricted.

At December 31, 2017, we received or posted cash and letters of credit for commodity hedging and trading activities as follows:

- $30 million in cash has been posted with counterparties as compared to $213 million posted at December 31, 2016;
- $4 million in cash has been received from counterparties as compared to $41 million received at December 31, 2016;
- $390 million in letters of credit have been posted with counterparties as compared to $363 million posted at December 31, 2016, and
- $3 million in letters of credit have been received from counterparties as compared to $10 million received at December 31, 2016.

### *Income Tax Matters*

EFH Corp files a U.S. federal income tax return that, prior to the Effective Date, included the results of our Predecessor, which was classified as a disregarded entity for U.S. federal income tax purposes. Subsequent to the Effective Date, the TCEH Debtors and the Contributed EFH Debtors are included in a consolidated group of which Vistra Energy is the corporate parent and are no longer included in the EFH Corp. consolidated group. Prior to the Effective Date, EFH Corp. and certain of its subsidiaries (including EFCH and TCEH) were parties to a Federal and State Income Tax Allocation Agreement, which provided, among other things, that any corporate member or disregarded entity in the EFH Corp. group was required to make payments to EFH Corp. in an amount calculated to approximate the amount of tax liability such entity would have owed if it filed a separate corporate tax return. Pursuant to the Plan of Reorganization, the TCEH Debtors and the Contributed EFH Debtors rejected this agreement on the Effective Date. Additionally, since the date of the Settlement Agreement, no further cash payments among the Debtors were made in respect of federal income taxes. EFH Corp. has elected to continue to allocate federal income taxes among the entities that are parties to the Federal and State Income Tax Allocation Agreement. The Settlement Agreement did not alter the allocation and payment for state income taxes, which continued to be settled prior to the Effective Date.

The TCEH Debtors and the Contributed EFH Debtors emerged from the Chapter 11 Cases on the Effective Date in a tax-free spin-off from EFH Corp that was part of a series of transactions that included a taxable component, which generated a taxable gain that was offset with available net operating losses (NOLs) of EFH Corp., substantially reducing the NOLs available to EFH Corp. in the future. As a result of the use of the NOLs, the taxable portion of the transaction resulted in no regular tax liability due and approximately $14 million of alternative minimum tax, payable to the IRS by EFH Corp. Pursuant to the Tax Matters Agreement, Vistra Energy had an obligation to reimburse EFH Corp. 50% of the alternative minimum tax, and approximately $7 million was reimbursed during the three months ended June 30, 2017. In October 2017, the 2016 federal tax return that included the results of EFCH, EFIH, Oncor Holdings and TCEH was filed with the IRS and resulted in $3 million payment from EFH Corp to Vistra Energy.

***Income Tax Payments*** — In the next 12 months, we expect to make federal income tax payments of approximately $40 million, which represents Vistra Energy's remaining estimated 2017 federal income tax liability. We also expect to make Texas margin tax payments of approximately $14 million in the next 12 months. For the year ended December 31, 2017, federal income tax payments totaled $41 million and Texas margin tax payments totaled $22 million.

### *Capitalization*

At both December 31, 2017 and 2016, our capitalization ratios consisted of 41% borrowing under the Vistra Energy Operations Facilities and other long-term debt (less amounts due currently) and 59% shareholders' equity. Total borrowings under the Vistra Energy Operations Facilities and other long-term debt to capitalization was 41% at both December 31, 2017 and 2016.

### *Financial Covenants*

The agreement governing the Vistra Operations Credit Facilities includes a covenant, solely with respect to the Revolving Credit Facility and solely during a compliance period (which, in general, is applicable when the aggregate revolving borrowings and issued revolving letters of credit (in excess of $100 million) exceed 30% of the revolving commitments), that requires the consolidated first lien net leverage ratio not exceed 4.25 to 1.00. Although the period ended December 31, 2017 was not a compliance period, we would have been in compliance with this financial covenant if it was required to be tested at such date.

See Note 12 to the Financial Statements for discussion of other covenants related to the Vistra Operations Credit Facilities.

### *Collateral Support Obligations*

The RCT has rules in place to assure that parties can meet their mining reclamation obligations. In September 2016, the RCT agreed to a collateral bond of up to $975 million to support Luminant's reclamation obligations. The collateral bond is effectively a first lien on all of Vistra Operations' assets (which ranks pari passu with the Vistra Operations Credit Facilities) that contractually enables the RCT to be paid (up to $975 million) before the other first lien lenders in the event of a liquidation of our assets. Collateral support relates to land mined or being mined and not yet reclaimed as well as land for which permits have been obtained but mining activities have not yet begun and land already reclaimed but not released from regulatory obligations by the RCT, and includes cost contingency amounts.

The PUCT has rules in place to assure adequate creditworthiness of each REP, including the ability to return customer deposits, if necessary. Under these rules, at December 31, 2017, Vistra Energy has posted letters of credit in the amount of $55 million with the PUCT, which is subject to adjustments.

ERCOT has rules in place to assure adequate creditworthiness of parties that participate in the day-ahead, real-time and congestion revenue rights markets operated by ERCOT. Under these rules, Vistra Energy has posted collateral support totaling $110 million in the form of letters of credit and $15 million in cash at December 31, 2017 (which is subject to daily adjustments based on settlement activity with ERCOT).

***Material Cross Default/Acceleration Provisions***

Certain of our contractual arrangements contain provisions that could result in an event of default if there was a failure under financing arrangements to meet payment terms or to observe covenants that could result in an acceleration of payments due. Such provisions are referred to as "cross default" or "cross acceleration" provisions.

A default by Vistra Operations or any of its restricted subsidiaries in respect of certain specified indebtedness in an aggregate amount in excess of $300 million may result in a cross default under the Vistra Operations Credit Facilities. Such a default would allow the lenders to accelerate the maturity of outstanding balances (approximately $4.3 billion at December 31, 2017) under such facilities.

Each of Vistra Operations' (or its subsidiaries') commodity hedging agreements and interest rate swap agreements that are secured with a lien on its assets on a pari passu basis with the Vistra Operations Credit Facilities lenders contains a cross default provision. An event of a default by Vistra Operations or any of its subsidiaries relating to indebtedness in excess of $300 million that results in the acceleration of such debt, would give each counterparty under these hedging agreements the right to terminate its hedge or interest rate swap agreement with Vistra Operations (or its applicable subsidiary) and require all outstanding obligations under such agreement to be settled.

Additionally, we enter into energy-related physical and financial contracts, the master forms of which contain provisions whereby an event of default or acceleration of settlement would occur if we were to default under an obligation in respect of borrowings in excess of thresholds, which may vary by contract.

***Contractual Obligations and Commitments***

The following table summarizes the amounts and related maturities of our contractual cash obligations at December 31, 2017. See Notes 12 and 13 to the Financial Statements for additional disclosures regarding these debts and noncancellable purchase obligations.

| **Contractual Cash Obligations:** | **Less Than One Year** | **One to Three Years** | **Three to Five Years** | **More Than Five Years** | **Total** |
|---|---|---|---|---|---|
| Debt – principal, including capital leases (a) | $ 44 | $ 88 | $ 87 | $ 4,189 | $ 4,408 |
| Debt – interest | 197 | 389 | 382 | 147 | 1,115 |
| Operating leases | 17 | 27 | 18 | 150 | 212 |
| Obligations under commodity purchase and services agreements (b) | 520 | 368 | 316 | 582 | 1,786 |
| Total contractual cash obligations | $ 778 | $ 872 | $ 803 | $ 5,068 | $ 7,521 |

___________

(a) Includes $4.311 billion of borrowings under the Vistra Operations Credit Facility and $97 million principal amount of long-term debt, including mandatorily redeemable preferred stock and capital leases. Excludes unamortized premiums, discounts and debt costs.

(b) Includes a long-term service and maintenance contract related to our generation assets, capacity payments, nuclear fuel and natural gas take-or-pay contracts, coal contracts, business services and nuclear related outsourcing and other purchase commitments. Amounts presented for variable priced contracts reflect the year-end 2017 price for all periods except where contractual price adjustment or index-based prices are specified.

The following are not included in the table above:

- the TRA obligation (see Note 9 to the Financial Statements);
- arrangements between affiliated entities and intercompany debt (see Note 19 to the Financial Statements);
- individual contracts that have an annual cash requirement of less than $1 million (however, multiple contracts with one counterparty that are more than $1 million on an aggregated basis have been included);
- contracts that are cancellable without payment of a substantial cancellation penalty, and
- employment contracts with management.

***Guarantees***

See Note 13 to the Financial Statements for discussion of guarantees.

## OFF–BALANCE SHEET ARRANGEMENTS

We do not have any off-balance sheet arrangements.

## COMMITMENTS AND CONTINGENCIES

See Note 13 to the Financial Statements for discussion of commitments and contingencies.

## CHANGES IN ACCOUNTING STANDARDS

See Note 1 to the Financial Statements for discussion of changes in accounting standards.

## Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Vistra Energy Corp.

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets of Vistra Energy Corp. and its subsidiaries (the "Company") as of December 31, 2017 and 2016 (Successor Company balance sheets), and the related statements of consolidated income (loss), consolidated comprehensive income (loss), consolidated cash flows, and consolidated equity, for the year ended December 31, 2017 and for the period October 3, 2016 through December 31, 2016 (Successor Company operations), the period January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 (Predecessor Company operations), the related notes, and the schedule listed in the Index at Item 15(b) (collectively referred to as the "financial statements"). In our opinion, the Successor Company financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows, for the year ended December 31, 2017 and for the period October 3, 2016 through December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Further, in our opinion, the Predecessor Company financial statements present fairly, in all material respects, the results of operations and cash flows of the Predecessor Company for the period January 1, 2016 through October 2, 2016 and the year ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

**Change in Accounting Principle**

As discussed in Note 1 to the financial statements, the accompanying financial statements have been retrospectively adjusted for the adoption of Accounting Standards Update (“ASU”) 2016-18 Statement of Cash Flows (Topic 230): Restricted Cash.

**Fresh-Start Reporting**

As discussed in Note 6 to the financial statements, on August 29, 2016 the Bankruptcy Court entered an order confirming the plan of reorganization which became effective on October 3, 2016. Accordingly, the accompanying financial statements have been prepared in conformity with Accounting Standards Codification Topic 852, *Reorganizations,* for the Successor Company as a new entity with assets, liabilities, and a capital structure having carrying values not comparable with prior periods as described in Note 1 to the financial statements.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s 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 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 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 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 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Dallas, TX
February 26, 2018 (June 15, 2018 as to the retrospective adjustments for the adoption of ASU 2016-18 described in Notes 1 and 21 and the schedule listed in the Index at Item 15(b) and the change in reportable segments described in Notes 1 and 20)

We have served as the Company's auditor since 2002.

**VISTRA ENERGY CORP.**
**STATEMENTS OF CONSOLIDATED INCOME (LOSS)**
**(Millions of Dollars, Except Per Share Amounts)**

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Operating revenues | $ 5,430 | $ 1,191 | $ 3,973 | $ 5,370 |
| Fuel, purchased power costs and delivery fees | (2,935) | (720) | (2,082) | (2,692) |
| Net gain from commodity hedging and trading activities | — | — | 282 | 334 |
| Operating costs | (973) | (208) | (664) | (834) |
| Depreciation and amortization | (699) | (216) | (459) | (852) |
| Selling, general and administrative expenses | (600) | (208) | (482) | (676) |
| Impairment of goodwill (Note 7) | — | — | — | (2,200) |
| Impairment of long-lived assets (Note 4) | (25) | — | — | (2,541) |
| Operating income (loss) | 198 | (161) | 568 | (4,091) |
| Other income (Note 21) | 37 | 10 | 19 | 18 |
| Other deductions (Note 21) | (5) | — | (75) | (93) |
| Interest expense and related charges (Note 10) | (193) | (60) | (1,049) | (1,289) |
| Impacts of Tax Receivable Agreement (Note 9) | 213 | (22) | — | — |
| Reorganization items (Note 5) | — | — | 22,121 | (101) |
| Income (loss) before income taxes | 250 | (233) | 21,584 | (5,556) |
| Income tax (expense) benefit (Note 8) | (504) | 70 | 1,267 | 879 |
| Net income (loss) | $ (254) | $ (163) | $ 22,851 | $ (4,677) |
| Weighted average shares of common stock outstanding: | | | | |
| Basic | 427,761,460 | 427,560,620 | | |
| Diluted | 427,761,460 | 427,560,620 | | |
| Net income (loss) per weighted average share of common stock outstanding: | | | | |
| Basic | $ (0.59) | $ (0.38) | | |
| Diluted | $ (0.59) | $ (0.38) | | |
| Dividend declared per share of common stock | $ — | $ 2.32 | | |

See Notes to the Consolidated Financial Statements.

**VISTRA ENERGY CORP.**
**STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME (LOSS)**
**(Millions of Dollars)**

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Net income (loss) | $ (254) | $ (163) | $ 22,851 | $ (4,677) |
| Other comprehensive income (loss), net of tax effects: | | | | |
| Effects related to pension and other retirement benefit obligations (net of tax (benefit) expense of $(6), $3, $— and $—) | (23) | 6 | — | — |
| Other comprehensive income, net of tax effects —cash flow hedges derivative value net loss related to hedged transactions recognized during the period (net of tax benefit of $— in all periods) | — | — | 1 | 2 |
| Total other comprehensive income (loss) | (23) | 6 | 1 | 2 |
| Comprehensive income (loss) | $ (277) | $ (157) | $ 22,852 | $ (4,675) |

See Notes to the Consolidated Financial Statements.

**VISTRA ENERGY CORP.**
**STATEMENTS OF CONSOLIDATED CASH FLOWS**
**(Millions of Dollars)**

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Cash flows — operating activities: | | | | |
| Net income (loss) | $ (254) | $ (163) | $ 22,851 | $ (4,677) |
| Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities: | | | | |
| Depreciation and amortization | 835 | 285 | 532 | 995 |
| Deferred income tax expense (benefit), net | 418 | (76) | (1,270) | (883) |
| Unrealized net (gain) loss from mark-to-market valuations of derivatives | 116 | 176 | 36 | (119) |
| Gain on extinguishment of liabilities subject to compromise (Note 5) | — | — | (24,344) | — |
| Net loss from adopting fresh start reporting (Note 6) | — | — | 2,013 | — |
| Contract claims adjustments of Predecessor (Note 5) | — | — | 13 | 54 |
| Noncash adjustment for estimated allowed claims related to debt (Note 5) | — | — | — | 896 |
| Adjustment to intercompany claims pursuant to Settlement Agreement (Note 5) | — | — | — | (1,037) |
| Impairment of goodwill (Note 7) | — | — | — | 2,200 |
| Impairment of long-lived assets (Note 4) | 25 | — | — | 2,541 |
| Write-off of intangible and other assets (Note 21) | — | — | 45 | 84 |
| Impacts of Tax Receivable Agreement (Note 9) | (213) | 22 | — | — |
| Increase in asset retirement obligation liability | 112 | — | — | — |
| Accretion expense | 60 | 6 | — | — |
| Other, net | 69 | 1 | 63 | 57 |
| Changes in operating assets and liabilities: | | | | |
| Affiliate accounts receivable/payable — net | — | — | 31 | (4) |
| Accounts receivable — trade | 7 | 135 | (216) | 17 |
| Inventories | 22 | 3 | 71 | 34 |
| Accounts payable — trade | (30) | (79) | 26 | 40 |
| Commodity and other derivative contractual assets and liabilities | (1) | (48) | 29 | 27 |
| Margin deposits, net | 146 | (193) | (124) | 129 |
| Accrued interest | (10) | 32 | (10) | 2 |
| Alcoa contract settlement (Note 4) | 238 | — | — | — |
| Tax Receivable Agreement payment (Note 9) | (26) | — | — | — |
| Major plant outage deferral | (66) | — | — | — |
| Other — net assets | 4 | (2) | (3) | (22) |
| Other — net liabilities | (66) | (18) | 19 | (97) |
| Cash provided by (used in) operating activities | 1,386 | 81 | (238) | 237 |

**VISTRA ENERGY CORP.**
**CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS**
**(Unaudited) (Millions of Dollars)**

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Cash flows — financing activities: | | | | |
| Repayments/repurchases of debt (Note 12) | (191) | — | (2,655) | (21) |
| Incremental Term Loan B Facility (Note 12) | — | 1,000 | — | — |
| Special Dividend (Note 14) | — | (992) | — | — |
| Net proceeds from issuance of preferred stock (Note 5) | — | — | 69 | — |
| Payments to extinguish claims of TCEH first lien creditors (Note 5) | — | — | (486) | — |
| Payment to extinguish claims of TCEH unsecured creditors (Note 5) | — | — | (429) | — |
| Borrowings under TCEH DIP Roll Facilities and DIP Facility (Note 12) | — | — | 4,680 | — |
| TCEH DIP Roll Facilities and DIP Facility financing fees | — | — | (112) | (9) |
| Other, net | (10) | (2) | (8) | — |
| Cash provided by (used in) financing activities | (201) | 6 | 1,059 | (30) |
| Cash flows — investing activities: | | | | |
| Capital expenditures | (114) | (48) | (230) | (337) |
| Nuclear fuel purchases | (62) | (41) | (33) | (123) |
| Solar development expenditures (Note 3) | (190) | — | — | — |
| Odessa acquisition (Note 3) | (355) | — | — | — |
| Lamar and Forney acquisition — net of cash acquired (Note 3) | — | — | (1,343) | — |
| Changes in restricted cash (Predecessor) | — | — | 233 | (123) |
| Proceeds from sales of nuclear decommissioning trust fund securities (Note 21) | 252 | 25 | 201 | 401 |
| Investments in nuclear decommissioning trust fund securities (Note 21) | (272) | (30) | (215) | (418) |
| Notes/advances due from affiliates | — | — | (41) | (37) |
| Other, net | 14 | 1 | 8 | (13) |
| Cash used in investing activities | (727) | (93) | (1,420) | (650) |
| | | | | |
| Net change in cash, cash equivalents and restricted cash (Successor); Net change in cash and cash equivalents (Predecessor) | 458 | (6) | (599) | (443) |
| Cash, cash equivalents and restricted cash — beginning balance (Successor); Cash and cash equivalents — beginning balance (Predecessor) | 1,588 | 1,594 | 1,400 | 1,843 |
| Cash, cash equivalents and restricted cash — ending balance (Successor); Cash and cash equivalents — ending balance (Predecessor) | $ 2,046 | $ 1,588 | $ 801 | $ 1,400 |

See Notes to the Consolidated Financial Statements.

**VISTRA ENERGY CORP.**
**CONSOLIDATED BALANCE SHEETS**
**(Millions of Dollars)**

| | Year Ended December 31, 2017 | 2016 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 1,487 | $ 843 |
| Restricted cash (Note 21) | 59 | 95 |
| Trade accounts receivable — net (Note 21) | 582 | 612 |
| Inventories (Note 21) | 253 | 285 |
| Commodity and other derivative contractual assets (Note 16) | 190 | 350 |
| Margin deposits related to commodity contracts | 30 | 213 |
| Prepaid expense and other current assets | 72 | 75 |
| Total current assets | 2,673 | 2,473 |
| Restricted cash (Note 21) | 500 | 650 |
| Investments (Note 21) | 1,240 | 1,064 |
| Property, plant and equipment — net (Note 21) | 4,820 | 4,443 |
| Goodwill (Note 7) | 1,907 | 1,907 |
| Identifiable intangible assets — net (Note 7) | 2,530 | 3,205 |
| Commodity and other derivative contractual assets (Note 16) | 58 | 64 |
| Accumulated deferred income taxes (Note 8) | 710 | 1,122 |
| Other noncurrent assets | 162 | 239 |
| Total assets | $ 14,600 | $ 15,167 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Long-term debt due currently (Note 12) | $ 44 | $ 46 |
| Trade accounts payable | 473 | 479 |
| Commodity and other derivative contractual liabilities (Note 16) | 224 | 359 |
| Margin deposits related to commodity contracts | 4 | 41 |
| Accrued taxes | 58 | 31 |
| Accrued taxes other than income | 136 | 128 |
| Accrued interest | 16 | 33 |
| Asset retirement obligations (Note 21) | 99 | 55 |
| Other current liabilities | 297 | 332 |
| Total current liabilities | 1,351 | 1,504 |
| Long-term debt, less amounts due currently (Note 12) | 4,379 | 4,577 |
| Commodity and other derivative contractual liabilities (Note 16) | 102 | 2 |
| Tax Receivable Agreement obligation (Note 9) | 333 | 596 |
| Asset retirement obligations (Note 21) | 1,837 | 1,671 |
| Other noncurrent liabilities and deferred credits (Note 21) | 256 | 220 |
| Total liabilities | 8,258 | 8,570 |

**VISTRA ENERGY CORP.**
**CONSOLIDATED BALANCE SHEETS**
**(Millions of Dollars)**

| | Year Ended December 31, | |
|---|---|---|
| Commitments and Contingencies (Note 13) | | |
| Total equity (Note 14): | | |
| Common stock (par value — $0.01; number of shares authorized — 1,800,000,000) (shares outstanding: December 31, 2017 — 428,398,802; December 31, 2016 — 427,580,232) | 4 | 4 |
| Additional paid-in-capital | 7,765 | 7,742 |
| Retained deficit | (1,410) | (1,155) |
| Accumulated other comprehensive income (loss) | (17) | 6 |
| Total equity | 6,342 | 6,597 |
| Total liabilities and equity | $ 14,600 | $ 15,167 |

See Notes to the Consolidated Financial Statements.

**VISTRA ENERGY CORP.**
**STATEMENTS OF CONSOLIDATED EQUITY**
**(Millions of Dollars)**

| | Common Stock (Successor) / Capital Account (Predecessor) | Additional Paid-In Capital (Successor) | Retained Deficit (Successor) | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|
| Shareholders' equity in Successor: | | | | | |
| Balances at October 3, 2016 | $ — | $ — | $ — | $ — | $ — |
| Shares issued upon Emergence | 4 | 7,737 | — | — | 7,741 |
| Effects of stock-based compensation | — | 4 | — | — | 4 |
| Other issuances of common stock | — | 1 | — | — | 1 |
| Net loss | — | — | (163) | — | (163) |
| Dividends declared on common stock | — | — | (992) | — | (992) |
| Pension and OPEB liability — change in funded status | — | — | — | 6 | 6 |
| Balances at December 31, 2016 | $ 4 | $ 7,742 | $ (1,155) | $ 6 | $ 6,597 |
| Net income | — | — | (254) | — | (254) |
| Effects of stock-based compensation | — | 23 | — | — | 23 |
| Pension and OPEB liability — change in funded status | — | — | — | (23) | (23) |
| Other | — | — | (1) | — | (1) |
| Balances at December 31, 2017 | $ 4 | $ 7,765 | $ (1,410) | $ (17) | $ 6,342 |
| | | | | | |
| Membership interests in Predecessor: | | | | | |
| Balances at December 31, 2014 | $ (18,174) | $ — | $ — | $ (35) | $ (18,209) |
| Net income | (4,677) | — | — | — | (4,677) |
| Cash flow hedges — change during period | — | — | — | 2 | 2 |
| Balances at December 31, 2015 | $ (22,851) | $ — | $ — | $ (33) | $ (22,884) |
| Net income | 22,851 | — | — | — | 22,851 |
| Cash flow hedges — change during period | — | — | — | 33 | 33 |
| Balances at October 2, 2016 | $ — | $ — | $ — | $ — | $ — |

See Notes to the Consolidated Financial Statements.

**VISTRA ENERGY CORP.**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

## 1. BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

### *Description of Business*

References in this report to "we," "our," "us" and "the Company" are to Vistra Energy and/or its subsidiaries in the Successor period, and to TCEH and/or its subsidiaries in the Predecessor periods, as apparent in the context. See *Glossary* for defined terms.

Vistra Energy is a holding company operating an integrated power business in Texas. Through our Luminant and TXU Energy subsidiaries, we are engaged in competitive electricity market activities including power generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity to end users. Prior to the Effective Date, TCEH was a holding company for subsidiaries principally engaged in the same activities as Vistra Energy.

Subsequent to the Effective Date, Vistra Energy has three reportable segments: (i) our Wholesale Generation segment, consisting largely of Luminant, (ii) our Retail Electricity segment, consisting largely of TXU Energy, and (iii) our Asset Closure segment, consisting of financial results associated with retired plant and mines. The Asset Closure segment was established as of January 1, 2018; however, these financial statements have been recast to reflect the changes resulting from the establishment of the Asset Closure segment. Prior to the Effective Date, there were no reportable business segments for our Predecessor. See Note 20 for further information concerning reportable business segments.

On the Petition Date, EFH Corp. and the substantial majority of its direct and indirect subsidiaries, including the Debtors, filed voluntary petitions for relief under the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware.

On the Effective Date, subsidiaries of TCEH that were Debtors in the Chapter 11 Cases (the TCEH Debtors) and certain EFH Corp. subsidiaries (the Contributed EFH Debtors) completed their reorganization under the Bankruptcy Code and emerged from the Chapter 11 Cases as subsidiaries of a newly formed company, Vistra Energy (our Successor). On the Effective Date, Vistra Energy was spun-off from EFH Corp. in a tax-free transaction to the former first lien creditors of TCEH (Spin-Off). As a result, as of the Effective Date, Vistra Energy is a holding company for subsidiaries principally engaged in competitive electricity market activities including power generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity to end users. TCEH is the Predecessor to Vistra Energy. See Note 5 for further discussion regarding the Chapter 11 Cases.

### *Basis of Presentation*

As of the Effective Date, Vistra Energy applied fresh start reporting under the applicable provisions of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 852, *Reorganizations* (ASC 852). Fresh start reporting included (1) distinguishing the consolidated financial statements of the entity that was previously in restructuring (TCEH, or the Predecessor) from the financial statements of the entity that emerges from restructuring (Vistra Energy, or the Successor), (2) accounting for the effects of the Plan of Reorganization, (3) assigning the reorganization value of the Successor entity by measuring all assets and liabilities of the Successor entity at fair value, and (4) selecting accounting policies for the Successor entity. The financial statements of Vistra Energy for periods subsequent to the Effective Date are not comparable to the financial statements of TCEH for periods prior to the Effective Date, as those previous periods do not give effect to any adjustments to the carrying values of assets or amounts of liabilities that resulted from the Plan of Reorganization and the related application of fresh start reporting. The reorganization value of Vistra Energy was assigned to its assets and liabilities in conformity with the procedures specified by FASB ASC 805, *Business Combinations* , and the portion of the reorganization value that was not attributable to identifiable tangible or intangible assets was recognized as goodwill. See Note 6 for further discussion of fresh start reporting.

The consolidated financial statements of the Predecessor reflect the application of ASC 852 as it applies to entities that have filed a petition for bankruptcy under Chapter 11 of the Bankruptcy Code. As a result, the consolidated financial statements of the Predecessor have been prepared as if TCEH was a going concern and contemplated the realization of assets and liabilities in the normal course of business. During the Chapter 11 Cases, the Debtors operated their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code. The guidance requires that transactions and events directly associated with the reorganization be distinguished from the ongoing operations of the business. In addition, the guidance provides for changes in the accounting and presentation of liabilities. Prior to the Effective Date, the Predecessor recorded the effects of the Plan of Reorganization in accordance with ASC 852. See *Predecessor Reorganization Items* in Note 5 for further discussion of these accounting and reporting changes.

The consolidated financial statements have been prepared in accordance with GAAP and on the same basis as the audited financial statements and related notes contained in our prospectus filed in May 2017 with the SEC pursuant to Rule 424(b) of the Securities Act. All intercompany items and transactions have been eliminated in consolidation. All dollar amounts in the financial statements and tables in the notes are stated in millions of U.S. dollars unless otherwise indicated.

***Use of Estimates***

Preparation of financial statements requires estimates and assumptions about future events that affect the reporting of assets and liabilities at the balance sheet dates and the reported amounts of revenue and expense, including fair value measurements, estimates of expected obligations, judgment related to the potential timing of events and other estimates. In the event estimates and/or assumptions prove to be different from actual amounts, adjustments are made in subsequent periods to reflect more current information.

***Derivative Instruments and Mark-to-Market Accounting***

We enter into contracts for the purchase and sale of electricity, natural gas, coal, uranium and other commodities utilizing instruments such as options, swaps, futures and forwards primarily to manage commodity price and interest rate risks. If the instrument meets the definition of a derivative under accounting standards related to derivative instruments and hedging activities, changes in the fair value of the derivative are recognized in net income as unrealized gains and losses. This recognition is referred to as mark-to-market accounting. The fair values of our unsettled derivative instruments under mark-to-market accounting are reported in the consolidated balance sheets as commodity and other derivative contractual assets or liabilities. We report derivative assets and liabilities in the consolidated balance sheets without taking into consideration netting arrangements we have with counterparties. Margin deposits that contractually offset these assets and liabilities are reported separately in the consolidated balance sheets, with the exception of certain margin amounts related to changes in fair value on certain CME transactions that, beginning in January 2017, are legally characterized as settlement of derivative contracts rather than collateral. When derivative instruments are settled and realized gains and losses are recorded, the previously recorded unrealized gains and losses and derivative assets and liabilities are reversed. See Notes 15 and 16 for additional information regarding fair value measurement and commodity and other derivative contractual assets and liabilities. A commodity-related derivative contract may be designated as a normal purchase or sale if the commodity is to be physically received or delivered for use or sale in the normal course of business. If designated as normal, the derivative contract is accounted for under the accrual method of accounting (not marked-to-market) with no balance sheet or income statement recognition of the contract until settlement.

Because derivative instruments are frequently used as economic hedges, accounting standards related to derivative instruments and hedging activities allow for hedge accounting, which provides for the designation of such instruments as cash flow or fair value hedges if certain conditions are met. At December 31, 2017 and 2016 , there were no derivative positions accounted for as cash flow or fair value hedges.

For the Successor period, we report commodity hedging and trading results as revenue, fuel expense or purchased power in the statements of consolidated income (loss) depending on the type of activity. Electricity hedges, financial natural gas hedges and trading activities are primarily reported as revenue. Physical or financial hedges for coal, diesel or uranium, along with physical natural gas trades, are primarily reported as fuel expense. For the Predecessor periods, all activity was reported as a net gain (loss) from commodity hedging and trading activities. Realized and unrealized gains and losses associated with interest rate swap transactions are reported in the statements of consolidated income (loss) in interest expense for both the Predecessor and Successor.

***Revenue Recognition***

We record revenue from retail electricity sales under the accrual method of accounting. Revenues are recognized when electricity is provided to customers on the basis of periodic cycle meter readings and include an estimated accrual for the revenues earned from the meter reading date to the end of the period (unbilled revenue).

We record wholesale generation revenue on an accrual basis for transactions that are not accounted for on a mark-to-market basis. These revenues primarily consist of physical electricity sales to ERCOT at the resource node, ERCOT ancillary service revenue for reliability services and certain other electricity sales. Revenue is recognized when electricity and other services are metered by ERCOT or delivered to our customers. See *Derivative Instruments and Mark-to-Market Accounting* for revenue recognition related to derivative contracts.

***Advertising Expense***

We expense advertising costs as incurred and include them within selling, general and administrative expenses. Advertising expenses totaled $44 million , $9 million , $35 million and $44 million for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively.

***Impairment of Long-Lived Assets***

We evaluate long-lived assets (including intangible assets with finite lives) for impairment whenever indications of impairment exist. The carrying value of such assets is deemed to be impaired if the projected undiscounted cash flows are less than the carrying value. If there is such impairment, a loss would be recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows, supported by available market valuations, if applicable. See Note 4 for discussion of impairments of certain long-lived assets recorded by the Predecessor.

Finite-lived intangibles identified as a result of fresh start reporting are amortized over their estimated useful lives based on the expected realization of economic effects. See Note 7 for details of intangible assets with indefinite lives, including discussion of fair value determinations.

***Goodwill and Intangible Assets with Indefinite Lives***

As part of fresh start reporting, reorganization value is generally allocated, first, to identifiable tangible assets, identifiable intangible assets and liabilities, then any remaining excess reorganization value is allocated to goodwill (see Note 6 ). We evaluate goodwill and intangible assets with indefinite lives for impairment at least annually, or when indications of impairment exist. As part of fresh start reporting, we have established October 1 as the date we evaluate goodwill and intangible assets with indefinite lives for impairment. The Predecessor's annual evaluation date was December 1. See Note 7 for details of goodwill, including discussion of fair value determinations and our Predecessor's goodwill impairments.

***Nuclear Fuel***

Nuclear fuel is capitalized and reported as a component of our property, plant and equipment in our consolidated balance sheets. Amortization of nuclear fuel is calculated on the units-of-production method and is reported as a component of fuel, purchased power costs and delivery fees in our statements of consolidated income (loss).

***Major Maintenance Costs***

Major maintenance costs incurred by the Successor during generation plant outages are deferred and amortized into operating costs over the period between the major maintenance outages for the respective asset. Other routine costs of maintenance activities are charged to expense as incurred and reported as operating costs in our statements of consolidated income (loss). The Predecessor charged all maintenance activities to expense as incurred.

***Defined Benefit Pension Plans and OPEB Plans***

On the Effective Date, EFH Corp. transferred sponsorship of certain employee benefit plans (including related assets), programs and policies to a subsidiary of Vistra Energy. Certain health care and life insurance benefits are offered to eligible employees and their dependents upon the retirement of such employee from the company and also offer pension benefits to eligible employees under collective bargaining agreements based on either a traditional defined benefit formula or a cash balance formula. Effective January 1, 2017, the OPEB plan was amended to discontinue the life insurance benefits for active employees. Costs of pension and OPEB plans are dependent upon numerous factors, assumptions and estimates.

Prior to the Effective Date, our Predecessor bore a portion of the costs of the EFH Corp. sponsored pension and OPEB plans and accounted for the arrangement under multiemployer plan accounting.

See Note 17 for additional information regarding pension and OPEB plans.

***Stock-Based Compensation***

Stock-based compensation is accounted for in accordance with ASC 718, *Compensation - Stock Compensation.* The fair value of our non-qualified stock options is estimated on the date of grant using the Black-Scholes option-pricing model. Forfeitures are recognized as they occur. We recognize compensation expense for graded vesting awards on a straight-line basis over the requisite service period for the entire award. See Note 18 for additional information regarding stock-based compensation.

***Sales and Excise Taxes***

Sales and excise taxes are accounted for as "pass through" items on the consolidated balance sheets with no effect on the statements of consolidated income (loss) ( *i.e.* , the tax is billed to customers and recorded as trade accounts receivable with an offsetting amount recorded as a liability to the taxing jurisdiction).

***Franchise and Revenue-Based Taxes***

Unlike sales and excise taxes, franchise and gross receipt taxes are not a "pass through" item. These taxes are imposed on us by state and local taxing authorities, based on revenues or kWh delivered, as a cost of doing business and are recorded as an expense. Rates we charge to customers are intended to recover our costs, including the franchise and gross receipt taxes, but we are not acting as an agent to collect the taxes from customers. We report franchise and revenue-based taxes in SG&A expense in our statements of consolidated income (loss).

***Income Taxes***

Subsequent to the Effective Date, Vistra Energy will file a consolidated U.S. federal income tax return. Prior to the Effective Date, EFH Corp. filed a consolidated U.S. federal income tax return that included the results of our Predecessor; however, our Predecessor's income tax expense and related balance sheet amounts were recorded as if it filed separate corporate income tax returns.

Deferred income taxes are provided for temporary differences between the book and tax basis of assets and liabilities as required under accounting rules. See Note 8 .

We report interest and penalties related to uncertain tax positions as current income tax expense. See Note 8 .

***Accounting for Contingencies***

Our financial results may be affected by judgments and estimates related to loss contingencies. Accruals for loss contingencies are recorded when management determines that it is probable that an asset has been impaired or a liability has been incurred and that such economic loss can be reasonably estimated. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events and estimates of the financial impacts of such events. See Note 13 for a discussion of contingencies.

***Cash and Cash Equivalents***

For purposes of reporting cash and cash equivalents, temporary cash investments purchased with a remaining maturity of three months or less are considered to be cash equivalents.

***Restricted Cash***

The terms of certain agreements require the restriction of cash for specific purposes. See Notes 12 and 21 for more details regarding restricted cash.

***Property, Plant and Equipment***

In connection with fresh start reporting, carrying amounts of property, plant and equipment were adjusted to estimated fair values as of the Effective Date (see Note 6 ). Significant improvements or additions to our property, plant and equipment that extend the life of the respective asset are capitalized at cost, while other costs are expensed when incurred. The cost of self-constructed property additions includes materials and both direct and indirect labor and applicable overhead, including payroll-related costs. Interest related to qualifying construction projects and qualifying software projects is capitalized in accordance with accounting guidance related to capitalization of interest cost. See Note 10 .

Depreciation of our property, plant and equipment (except for nuclear fuel) is calculated on a straight-line basis over the estimated service lives of the properties. Depreciation expense is calculated on an asset-by-asset basis. Estimated depreciable lives are based on management's estimates of the assets' economic useful lives. See Note 21 .

***Asset Retirement Obligations (ARO)***

A liability is initially recorded at fair value for an asset retirement obligation associated with the legal obligation associated with law, regulatory, contractual or constructive retirement requirements of tangible long-lived assets in the period in which it is incurred if a fair value is reasonably estimable. At initial recognition of an ARO obligation, an offsetting asset is also recorded for the long-lived asset that the liability corresponds with, which is subsequently depreciated over the estimated useful life of the asset. These liabilities primarily relate to our nuclear generation plant decommissioning, land reclamation related to lignite mining, removal of lignite/coal-fueled plant ash treatment facilities and generation plant asbestos removal and disposal costs. Over time, the liability is accreted for the change in present value and the initial capitalized costs are depreciated over the remaining useful lives of the assets. Generally, changes in estimates related to ARO obligations are recorded as increases or decreases to the liability and related asset as information becomes available. Changes in estimates related to assets that have been retired or for which capitalized costs are not recoverable are reflected in income. See Note 21 .

***Inventories***

Inventories consist of materials and supplies, fuel stock and natural gas in storage. Materials and supplies inventory is valued at weighted average cost and is expensed or capitalized when used for repairs/maintenance or capital projects, respectively. Fuel stock and natural gas in storage are reported at the lower of cost (on a weighted average basis) or market. We expect to recover the value of inventory costs in the normal course of business. See Note 21 .

***Investments***

Investments in a nuclear decommissioning trust fund are carried at current market value in the consolidated balance sheets. Assets related to employee benefit plans represent investments held to satisfy deferred compensation liabilities and are recorded at current market value. See Note 21 for discussion of these and other investments.

***Tax Receivable Agreement***

The Company accounts for its obligations under the Tax Receivable Agreement (TRA) as a liability in our consolidated balance sheets. The carrying value of the TRA obligation represents the discounted amount of projected payments under the TRA. The projected payments are based on certain assumptions, including but not limited to (a) the federal corporate income tax rate and (b) estimates of our taxable income in the current and future years. Our taxable income takes into consideration the current federal tax code and reflects our current estimates of future results of the business.

The carrying value of the obligation is being accreted to the amount of the gross expected obligation using the effective interest method. Changes in the estimated amount of this obligation resulting from changes to either the timing or amount of TRA payments are recognized in the period of change and are included on our statement of consolidated income (loss) under the heading of Impacts of Tax Receivable Agreement.

***Changes in Accounting Standards***

In May 2014, the FASB issued Accounting Standards Update 2014-09, *Revenue from Contracts with Customers (Topic 606)* , which was further amended through several updates issued by the FASB in 2016 and 2017. The guidance under Topic 606 provides the core principle and key steps in determining the recognition of revenue and expands disclosure requirements related to revenue recognition. We adopted the new standard on January 1, 2018 using the modified retrospective method and elected the practical expedient available under Topic 606 for measuring progress toward complete satisfaction of a performance obligation and for disclosure requirements of remaining performance obligations. The practical expedient allows an entity to recognize revenue in the amount to which the entity has the right to invoice such that the entity has a right to the consideration in an amount that corresponds directly with the value to the customer for performance completed to date. In recent periods, we completed an assessment of all of our performance obligations in our contractual relationships and continued to assess the expanded disclosure requirements. The standard will require expanded disclosure related to revenue from contracts with customers and the related performance obligations. The adoption of the standard will not have a material effect on our results of operations, cash flows or financial condition.

In February 2016, the FASB issued Accounting Standards Update 2016-02 (ASU 2016-02), *Leases* . The ASU amends previous GAAP to require the recognition of lease assets and liabilities for operating leases. The ASU will be effective for fiscal years beginning after December 15, 2018, including interim periods within those years. Retrospective application to comparative periods presented will be required in the year of adoption. We are currently evaluating the impact of this ASU on our financial statements.

In November 2016, the FASB issued ASU 2016-18 *Statement of Cash Flows (Topic 230): Restricted Cash* . The ASU requires restricted cash to be included in the cash and cash equivalents and a reconciliation between the change in cash and cash equivalents and the amounts presented on the balance sheet. The ASU modifies the presentation of our statements of consolidated cash flows, but does not have a material impact on our statements of consolidated net income and consolidated balance sheets. We adopted the standard on January 1, 2018. However, the adoption of this ASU has been reflected on a retrospective basis in the financial statements of the Successor. For the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, our statements of consolidated cash flows previously reflected sources of cash from investing activities of $186 million and $48 million , respectively, reported as changes in restricted cash that are now reported in net change in cash, cash equivalents and restricted cash. See the statements of consolidated cash flows and Note 21 for disclosures related to the adoption of this accounting standard.

In January 2017, the FASB issued ASU 2017-01 *Business Combinations (Topic 805): Clarifying the Definition of a Business* . The ASU provides an updated model for determining if acquired assets and liabilities constitute a business. In a business combination, the acquired assets and liabilities are recognized at fair value and goodwill could be recognized. In an asset acquisition, the assets are allocated value based on relative fair value and no goodwill is recognized. The ASU narrows the definition of a business. We adopted this standard in the first quarter of 2017. ASU 2017-01 did not have a material impact on our financial statements.

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment* (ASU 2017-04). The ASU provides for the elimination of Step 2 from the goodwill impairment test. If impairment charges are recognized, the amount recorded will be the amount by which the carrying amount exceeds the reporting unit's fair value with certain limitations. We adopted this standard in the first quarter of 2017. ASU 2017-04 did not have a material impact on our financial statements.

## 2. MERGER AGREEMENT

On October 29, 2017, Vistra Energy and Dynegy, entered into the Merger Agreement. Upon the terms and subject to the conditions set forth in the Merger Agreement, which has been approved by the boards of directors of Vistra Energy and Dynegy, Dynegy will merge with and into Vistra Energy, with Vistra Energy continuing as the surviving corporation. The Merger is intended to qualify as a tax-free reorganization under the Internal Revenue Code, as amended, so that none of Vistra Energy, Dynegy or any of the Dynegy stockholders will recognize any gain or loss in the transaction, except that Dynegy stockholders could recognize a gain or loss with respect to cash received in lieu of fractional shares of Vistra Energy's common stock. We expect that Vistra Energy will be the acquirer for both federal tax and accounting purposes.

Upon the closing of the Merger, each issued and outstanding share of Dynegy common stock, par value $0.01 per share, other than shares owned by Vistra Energy or its subsidiaries, held in treasury by Dynegy or held by a subsidiary of Dynegy, will automatically be converted into the right to receive 0.652 shares of common stock, par value $0.01 per share, of Vistra Energy (the Exchange Ratio), except that cash will be paid in lieu of fractional shares, which we expect will result in Vistra Energy's stockholders and Dynegy's stockholders owning approximately 79% and 21% , respectively, of the combined company. Dynegy stock options and equity-based awards outstanding immediately prior to the Effective Time will generally automatically convert upon completion of the Merger into stock options and equity-based awards, respectively, with respect to Vistra Energy's common stock, after giving effect to the Exchange Ratio.

The Merger Agreement also provides that, upon the closing of the Merger, the board of directors of the combined company will be comprised of 11 members, consisting of (a) the eight current directors of Vistra Energy and (b) three of Dynegy's current directors, of whom one will be a Class I director, one will be a Class II director and one will be a Class III director, unless the closing of the Merger occurs after the date of Vistra Energy's 2018 Annual Meeting of Stockholders, in which case one will be a Class I director and two will be Class II directors.

Completion of the Merger is subject to various customary conditions, including, among others, (a) approval by Vistra Energy's stockholders of the issuance of Vistra Energy's common stock in the Merger, (b) adoption of the Merger Agreement by Vistra Energy's stockholders and Dynegy's stockholders, (c) receipt of all requisite regulatory approvals, which includes approvals of the FERC, the PUCT, the Federal Communications Commission and the New York Public Service Commission, and the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, (HSR Waiting Period) and (d) the approval of the listing of shares to be issued on the NYSE. Each party's obligation to consummate the Merger is also subject to certain additional customary conditions, including (i) subject to certain exceptions, the accuracy of the representations and warranties of the other party, (ii) performance in all material respects by the other party of its obligations under the Merger Agreement and (iii) the receipt by such party of an opinion from its counsel to the effect that the Merger will qualify as a tax-free reorganization within the meaning of the Code. The HSR Waiting Period expired on February 5, 2018.

The Merger Agreement contains customary representations, warranties and covenants of Vistra Energy and Dynegy, including, among others, covenants (a) to conduct their respective businesses in the ordinary course during the interim period between the execution of the Merger Agreement and completion of the Merger, (b) not to take certain actions during the interim period except with the consent of the other party, (c) that Vistra Energy and Dynegy will convene and hold meetings of their respective stockholders to obtain the required stockholder approvals, and (d) that the parties use their respective reasonable best efforts to take all actions necessary to obtain all governmental and regulatory approvals and consents (except that Vistra Energy shall not be required, and Dynegy shall not be permitted, to take any action that constitutes or would reasonably be expected to have certain specified burdensome effects). Each of Vistra Energy and Dynegy is also subject to restrictions on its ability to solicit alternative acquisition proposals and to provide information to, and engage in discussion with, third parties regarding such proposals, except under limited circumstances to permit Vistra Energy's and Dynegy's boards of directors to comply with their respective fiduciary duties.

The Merger Agreement contains certain termination rights for both Vistra Energy and Dynegy, including in specified circumstances in connection with an alternative acquisition proposal that has been determined to be a superior offer. Upon termination of the Merger Agreement, under specified circumstances (a) for a failure by Vistra Energy to obtain certain requisite regulatory approvals, Vistra Energy may be required to pay Dynegy a termination fee of $100 million , (b) in connection with a superior offer, acquisition proposal or unforeseeable material intervening event, Vistra Energy may be required to pay a termination fee to Dynegy of $100 million , and (c) in connection with a superior offer, acquisition proposal or an unforeseeable material intervening event, Dynegy may be required to pay to Vistra Energy a termination fee of $87 million . In addition, if the Merger Agreement is terminated (i) because Vistra Energy's stockholders do not approve the issuance of Vistra Energy's common stock in the Merger or do not adopt the Merger Agreement, then Vistra Energy will be obligated to reimburse Dynegy for its reasonable out-of-pocket fees and expenses incurred in connection with the Merger Agreement, or (ii) because Dynegy's stockholders do not adopt the Merger Agreement, then Dynegy will reimburse Vistra Energy for its reasonable out-of-pocket fees and expenses incurred in connection with the Merger Agreement, each of which is subject to a cap of $22 million . Such expense reimbursement may be deducted from the foregoing termination fees, if ultimately payable.

The Merger is subject to certain risks and uncertainties, and there can be no assurance that we will be able to complete the Merger on the expected timeline or at all.

*Merger Support Agreements* — Concurrently with the execution of the Merger Agreement, certain stockholders of Vistra Energy, including affiliates of Apollo Management Holdings L.P. (collectively, the Apollo Entities), affiliates of Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P. (collectively, the Brookfield Entities) and certain affiliates of Oaktree Capital Management, L.P. (Oaktree), such agreements representing in the aggregate approximately 34% of the shares of Vistra Energy's common stock as of October 29, 2017 that will be entitled to vote on the Merger, and certain stockholders of Dynegy, including Terawatt Holdings, LP, an affiliate of certain affiliated investment funds of Energy Capital Partners III, LLC (Terawatt) and certain affiliates of Oaktree, such agreements representing in the aggregate approximately 21% of the shares of Dynegy's common stock as of October 29, 2017 that will be entitled to vote on the Merger, have entered into the Merger Support Agreements, pursuant to which each such stockholder agreed to vote their shares of common stock of Vistra Energy or Dynegy, as applicable, to adopt the Merger Agreement, and in the case of stockholders of Vistra Energy, approve the stock issuance. The Merger Support Agreements will automatically terminate upon a change of recommendation by the applicable board of directors or the termination of the Merger Agreement in accordance with its terms.

## 3. ACQUISITION AND DEVELOPMENT OF GENERATION FACILITIES

***Odessa Acquisition (Successor)***

In August 2017, La Frontera Holdings, LLC (La Frontera), an indirect wholly owned subsidiary of Vistra Energy, purchased a 1,054 MW CCGT natural gas fueled generation plant (and other related assets and liabilities) located in Odessa, Texas (Odessa Facility) from Odessa-Ector Power Partners, L.P., an indirect wholly owned subsidiary of Koch Ag & Energy Solutions, LLC (Koch) (altogether, the Odessa Acquisition). La Frontera paid an aggregate purchase price of approximately $355 million , plus a five-year earn-out provision, to acquire the Odessa Facility. The purchase price was funded by cash on hand.

The Odessa Acquisition was accounted for as an asset acquisition. Substantially all of the approximately $355 million purchase price was assigned to property, plant and equipment in our consolidated balance sheet. Additionally, the initial fair value associated with an earn-out provision of approximately $16 million was included as consideration in the overall purchase price. The earn-out provision requires cash payments to be made to Koch if spark-spreads related to the pricing point of the Odessa Facility exceed certain thresholds. Subsequent to the acquisition, the earn-out provision has been accounted for as a derivative in our consolidated financial statements.

***Upton Solar Development (Successor)***

In May 2017, we acquired the rights to develop, construct and operate a utility scale solar photovoltaic power generation facility in Upton County, Texas (Upton). As part of this project, we entered a turnkey engineering, procurement and construction agreement to construct the approximately 180 MW facility. For the year ended December 31, 2017 , we have spent approximately $190 million related to this project primarily for progress payments under the engineering, procurement and construction agreement and the acquisition of the development rights. We currently estimate that the facility will begin operations in the spring of 2018.

***Lamar and Forney Acquisition (Predecessor)***

In April 2016, Luminant purchased all of the membership interests in La Frontera, the indirect owner of two combined-cycle gas turbine (CCGT) natural gas fueled generation facilities representing nearly 3,000 MW of capacity located in ERCOT, from a subsidiary of NextEra Energy, Inc. (the Lamar and Forney Acquisition). The aggregate purchase price was approximately $1.313 billion , which included the repayment of approximately $950 million of existing project financing indebtedness of La Frontera at closing, plus approximately $236 million for cash and net working capital. The purchase price was funded by cash-on-hand and additional borrowings under our Predecessor's DIP Facility totaling $1.1 billion . After completing the acquisition, we repaid approximately $230 million of borrowings under our Predecessor's DIP Revolving Credit Facility primarily utilizing cash acquired in the transaction. La Frontera and its subsidiaries were subsidiary guarantors under our Predecessor's DIP Roll Facilities and, on the Effective Date, became subsidiary guarantors under the Vistra Operations Credit Facilities (see Note 12 ).

***Predecessor Purchase Accounting*** — The Lamar and Forney Acquisition was accounted for in accordance with ASC 805, *Business Combinations* (ASC 805), with identifiable assets acquired and liabilities assumed recorded at their estimated fair values on the acquisition date.

To fair value the acquired property, plant and equipment, we used a discounted cash flow analysis, classified as Level 3 within the fair value hierarchy levels (see Note 15 ). This discounted cash flow model was created for each generation facility based on its remaining useful life. The discounted cash flow model included gross margin forecasts for each power generation facility determined using forward commodity market prices obtained from long-term forecasts. We also used management's forecasts of generation output, operations and maintenance expense, SG&A and capital expenditures. The resulting cash flows, estimated based upon the age of the assets, efficiency, location and useful life, were then discounted using plant specific discount rates of approximately 9% .

The following table summarizes the consideration paid and the allocation of the purchase price to the fair value amounts recognized for the assets acquired and liabilities assumed related to the Lamar and Forney Acquisition as of the acquisition date. During the three months ended September 30, 2016, the working capital adjustment included in the purchase price was finalized between the parties, and the purchase price allocation was completed.

| | | |
|---|---|---|
| Cash paid to seller at close | $ | 603 |
| Net working capital adjustments | | (4) |
| Consideration paid to seller | | 599 |
| Cash paid to repay project financing at close | | 950 |
| Total cash paid related to acquisition | $ | 1,549 |
| Cash and cash equivalents | $ | 210 |
| Property, plant and equipment — net | | 1,316 |
| Commodity and other derivative contractual assets | | 47 |
| Other assets | | 44 |
| Total assets acquired | | 1,617 |
| Commodity and other derivative contractual liabilities | | 53 |
| Trade accounts payable and other liabilities | | 15 |
| Total liabilities assumed | | 68 |
| Identifiable net assets acquired | $ | 1,549 |

The Lamar and Forney Acquisition did not result in the recording of goodwill since the purchase price did not exceed the fair value of the net assets acquired.

***Unaudited Pro Forma Financial Information*** — The following unaudited pro forma financial information for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 assumes that the Lamar and Forney Acquisition occurred on January 1, 2015. The unaudited pro forma financial information is provided for information purposes only and is not necessarily indicative of the results of operations that would have occurred had the Lamar and Forney Acquisition been completed on January 1, 2015, nor is the unaudited pro forma financial information indicative of future results of operations.

| | Predecessor | |
|---|---|---|
| | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Revenues | $ 4,116 | $ 6,133 |
| Net income (loss) | $ 22,835 | $ (4,671) |

The unaudited pro forma financial information includes adjustments for incremental depreciation as a result of the fair value determination of the net assets acquired and interest expense on borrowings under our Predecessor's DIP Roll Facilities.

## 4. DISPOSITION OF GENERATION FACILITIES

***Retirement of Generation Facilities***

Luminant announced plans to retire three power plants with a total installed nameplate generation capacity of approximately 4,167 MW and two lignite mines. The plants were retired in January and February 2018. Luminant decided to retire these units given that they are projected to be uneconomic based on current market conditions and given the significant environmental costs associated with operating such units. In the case of the Sandow units, the decision also reflected the execution of a Settlement Agreement discussed below. The following table details the units retired.

| Name | Location (all in the state of Texas) | Fuel Type | Installed Nameplate Generation Capacity (MW) | Number of Units | Date Units Taken Offline |
|---|---|---|---|---|---|
| Monticello | Titus County | Lignite/Coal | 1,880 | 3 | January 4, 2018 |
| Sandow | Milam County | Lignite | 1,137 | 2 | January 11, 2018 |
| Big Brown | Freestone County | Lignite/Coal | 1,150 | 2 | February 12, 2018 |
| Total | | | 4,167 | 7 | |

In September and October 2017, we decided to retire our Monticello, Sandow and Big Brown plants and a related mine which supplies the Sandow plants. Management had previously announced its decisions to retire mines which supply the Monticello and Big Brown plants. The Monticello and Sandow plants were retired in January and the Big Brown plant in February 2018. We recorded a charge of approximately $206 million related to the retirements, including employee-related severance costs, non-cash charges for writing off materials inventory and capitalized improvements and changes to the timing and amounts of asset retirement obligations for mining and plant-related reclamation at these facilities. The charge, all of which related to our Asset Closure segment, was recorded to operating costs and impairment of long-lived assets in our statements of consolidated income (loss). In addition, we will continue the ongoing reclamation work at the plants' mines.

In October 2017, the Company and Alcoa entered into a contract termination agreement pursuant to which the parties agreed to an early settlement of a long-standing power and mining agreement. In consideration for the early termination, Alcoa made a payment to Luminant of approximately $238 million in October 2017. In the three months ended December 31, 2017, we recorded a gain related to the impacts of the Settlement Agreement in our consolidated financial statements totaling approximately $11 million , which included the receipt of the cash payment, the acquisition of real property and the incurrence of certain liabilities and asset retirement obligations associated with the real property acquired, along with the elimination of a related electric supply contract intangible asset on our consolidated balance sheet (see Note 7 ). The contract had been important to the overall economic viability of the Sandow plant.

*Regulatory Review* — As part of the retirement process, Luminant filed notices with ERCOT, which triggered a reliability review regarding such proposed retirements. In October and November 2017, ERCOT determined the units were not needed for reliability, and the units were taken offline in January and February 2018.

***Gas Plant Sales Process***

In conjunction with the regulatory review process as part of the Merger Agreement with Dynegy Inc., we are conducting a competitive sales process for our Stryker Creek, Graham and Trinidad plants that would reduce our overall installed generation capacity in the ERCOT market. Pursuant to that sales process, we have classified our Stryker Creek, Graham and Trinidad natural gas generation facilities with a total installed nameplate generation capacity of approximately 1,559 MW as assets held-for sale. At December 31, 2017 , these assets totaled $16 million and are included in other current assets in the consolidated balance sheet.

***Impairment of Lignite/Coal Fueled Generation and Mining Assets***

We evaluated our generation assets for impairment during 2015 as a result of impairment indicators related to the continued decline in forecasted wholesale electricity prices in ERCOT. Our evaluations concluded that impairments existed, and the carrying values at our Big Brown, Martin Lake, Monticello, Sandow 4 and Sandow 5 generation facilities and related mining facilities were reduced in total by $2.541 billion .

Our fair value measurement for these assets was determined based on an income approach that utilized probability-weighted estimates of discounted future cash flows, which were Level 3 fair value measurements (see Note 15 ). Key inputs into the fair value measurement for these assets included current forecasted wholesale electricity prices in ERCOT, forecasted fuel prices, capital and operating expenditure forecasts and discount rates.

## 5. EMERGENCE FROM CHAPTER 11 CASES

On the Petition Date, EFH Corp. and the substantial majority of its direct and indirect subsidiaries, including EFIH, EFCH and TCEH, but excluding the Oncor Ring-Fenced Entities, filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. On the Effective Date, the TCEH Debtors and the Contributed EFH Debtors completed their reorganization under the Bankruptcy Code and emerged from the Chapter 11 Cases as subsidiaries of Vistra Energy.

***Separation of Vistra Energy from EFH Corp. and its Subsidiaries***

Upon the Effective Date, Vistra Energy separated from EFH Corp. pursuant to a tax-free spin-off transaction that was part of a series of transactions that included a taxable component. The taxable portion of the transaction generated a taxable gain that resulted in no regular tax liability due to available net operating loss carryforwards of EFH Corp. The transaction did result in an alternative minimum tax liability estimated to be approximately $14 million payable by EFH Corp. to the IRS. Pursuant to the Tax Matters Agreement, Vistra Energy had an obligation to reimburse EFH Corp. 50% of the estimated alternative minimum tax, and approximately $7 million was reimbursed during the three months ended June 30, 2017. In October 2017, the 2016 federal tax return that included the results of EFCH, EFIH, Oncor Holdings and TCEH was filed with the IRS and resulted in a $3 million payment from EFH Corp. to Vistra Energy. The spin-off transaction resulted in Vistra Energy, including the TCEH Debtors and the Contributed EFH Debtors, no longer being an affiliate of EFH Corp. and its subsidiaries.

*Separation Agreement*

On the Effective Date, EFH Corp., Vistra Energy and a subsidiary of Vistra Energy entered into a separation agreement that provided for, among other things, the transfer of certain assets and liabilities by EFH Corp., EFCH and TCEH to Vistra Energy. Among other things, EFH Corp., EFCH and/or TCEH, as applicable, (a) transferred the TCEH Debtors and certain contracts and assets (and related liabilities) primarily related to the business of the TCEH Debtors to Vistra Energy, (b) transferred sponsorship of certain employee benefit plans (including related assets), programs and policies to a subsidiary of Vistra Energy and (c) assigned certain employment agreements from EFH Corp. and certain of the Contributed EFH Debtors to a subsidiary of Vistra Energy.

*Tax Matters Agreement*

On the Effective Date, Vistra Energy and EFH Corp. entered into the Tax Matters Agreement, which provides for the allocation of certain taxes among the parties and for certain rights and obligations related to, among other things, the filing of tax returns, resolutions of tax audits and preserving the tax-free nature of the spin-off.

*Settlement Agreement*

The Debtors, the Sponsor Group, certain settling TCEH first lien creditors, certain settling TCEH second lien creditors, certain settling TCEH unsecured creditors and the official committee of unsecured creditors of the TCEH Debtors entered into a settlement agreement (the Settlement Agreement) in August 2015 (as amended in September 2015 and approved by the Bankruptcy Court in December 2015) to settle, among other things, (a) intercompany claims among the Debtors, (b) claims and causes of actions against holders of first lien claims against TCEH and the agents under the TCEH Senior Secured Facilities, (c) claims and causes of action against holders of interests in EFH Corp. and certain related entities and (d) claims and causes of action against each of the Debtors' current and former directors, the Sponsor Group, managers and officers and other related entities.

***Tax Matters***

In July 2016, EFH Corp. received a private letter ruling from the IRS in connection with our emergence from bankruptcy, which provides, among other things, for certain rulings regarding the qualification of (a) the transfer of certain assets and ordinary course operating liabilities to Vistra Energy and (b) the distribution of the equity of Vistra Energy, the cash proceeds from Vistra Energy debt, the cash proceeds from the sale of preferred stock in a newly formed subsidiary of Vistra Energy, and the right to receive payments under a tax receivables agreement, to holders of TCEH first lien claims, as a reorganization qualifying for tax-free treatment.

***Pre-Petition Claims***

On the Effective Date, the TCEH Debtors (together with the Contributed EFH Debtors) emerged from the Chapter 11 Cases and discharged approximately $33.8 billion in LSTC. Initial distributions related to the allowed claims asserted against the TCEH Debtors and the Contributed EFH Debtors commenced subsequent to the Effective Date. As of December 31, 2017 , the TCEH Debtors have approximately $52 million in escrow to (1) distribute to holders of currently contingent and/or disputed unsecured claims that become allowed and/or (2) make further distributions to holders of previously allowed unsecured claims, if applicable. Additionally, the TCEH Debtors have approximately $7 million in escrow to pay remaining professional fees incurred in the Chapter 11 Cases. The remaining contingent and/or disputed claims against the TCEH Debtors consist primarily of unsecured legal claims, including asbestos claims. These remaining claims and the related escrow balance for the claims are recorded in Vistra Energy's consolidated balance sheet as other current liabilities and current restricted cash, respectively. A small number of other disputed, de minimis claims that are asserted as being entitled to priority and/or against the Contributed EFH Debtors, if allowed, will be paid by Vistra Energy, but all non-priority unsecured claims, including asbestos claims arising before the Petition Date, will be satisfied solely from the approximately $52 million in escrow.

***Predecessor Reorganization Items***

Expenses and income directly associated with the Chapter 11 Cases are reported separately in the statements of consolidated income (loss) as reorganization items as required by ASC 852, *Reorganizations* . Reorganization items also included adjustments to reflect the carrying value of LSTC at their estimated allowed claim amounts, as such adjustments were determined. The following table presents reorganization items incurred in the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively, as reported in the statements of consolidated income (loss):

| | Predecessor | |
|---|---|---|
| | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Gain on reorganization adjustments (Note 6) | $ (24,252) | $ — |
| Loss from the adoption of fresh start reporting | 2,013 | — |
| Expenses related to legal advisory and representation services | 55 | 141 |
| Expenses related to other professional consulting and advisory services | 39 | 69 |
| Contract claims adjustments | 13 | 54 |
| Noncash adjustment for estimated allowed claims related to debt | — | 896 |
| Adjustment to affiliate claims pursuant to Settlement Agreement (Note 19) | — | (635) |
| Gain on settlement of debt held by affiliates (Note 19) | — | (382) |
| Gain on settlement of interest on debt held by affiliates | — | (20) |
| Sponsor management agreement settlement | — | (19) |
| Contract assumption adjustments | — | (14) |
| Fees associated with extension/completion of the DIP Facility | — | 9 |
| Other | 11 | 2 |
| Total reorganization items | $ (22,121) | $ 101 |

## 6. FRESH START REPORTING

As of the Effective Date, Vistra Energy applied fresh start reporting under the applicable provisions of ASC 852. In order to apply fresh-start reporting, ASC 852 requires two criteria to be satisfied: (1) that total post petition liabilities and allowed claims immediately before the date of confirmation of the Plan of Reorganization be in excess of reorganization value and (2) that holders of our Predecessor's voting shares immediately before confirmation of the Plan receive less than 50% of the voting shares of the emerging entity. Vistra Energy met both criteria. Under ASC 852, application of fresh start reporting is required on the date on which a plan of reorganization is confirmed by a bankruptcy court and all material conditions to the plan of reorganization are satisfied. All material conditions to the Plan of Reorganization were satisfied on the Effective Date, including the execution of the Spin-Off.

***Reorganization Value***

A third-party valuation specialist submitted a report to the Bankruptcy Court in July 2016 assuming an emergence from bankruptcy as of December 31, 2016. This report provided an estimated value range for the total Vistra Energy enterprise. Management selected an enterprise value within that range of $10.5 billion . The enterprise value submitted by the valuation specialist was based upon:

- historical financial information of our Predecessor for recent years and interim periods;
- certain internal financial and operating data of our Predecessor;
- certain financial, tax and operational forecasts of Vistra Energy;
- certain publicly available financial data for comparable companies to the operating business of Vistra Energy;
- the Plan of Reorganization and related documents;
- certain economic and industry information relevant to the operating business, and
- other studies, analyses and inquiries.

The valuation analysis for Vistra Energy included (i) a discounted cash flow calculation and (ii) peer group company analysis. Equal weighting was assigned to the two methodologies, before adding the value of the tax basis step-up resulting from certain transactions pursuant to the Plan of Reorganization, which was valued separately. The estimated future cash flows included annual forecasts through 2021. A terminal value was included in the discounted cash flow calculation using an exit multiple approach based on the cash flows of the final year of the forecast period.

The valuation analysis used a discount rate of approximately 7% . The determination of the discount rate takes into consideration the capital structure, credit ratings and current debt yields of comparable publicly traded companies as well as an estimate of return on equity that reflects historical market returns and current market volatility for the industry.

Although the Company believes the assumptions and estimates used by the valuation specialist to develop the enterprise value are reasonable and appropriate, different assumption and estimates could materially impact the analysis and resulting conclusions.

Under ASC 852, reorganization value is generally allocated, first, to identifiable tangible assets, identifiable intangible assets and liabilities, then any remaining excess reorganization value is allocated to goodwill. Vistra Energy estimates its reorganization value of assets at approximately $15.161 billion as of October 3, 2016, which consists of the following:

| | | |
|---|---|---|
| Business enterprise value | $ | 10,500 |
| Cash excluded from business enterprise value | | 1,594 |
| Deferred asset related to prepaid capital lease obligation | | 38 |
| Current liabilities, excluding short-term portion of debt and capital leases | | 1,123 |
| Noncurrent, non-interest bearing liabilities | | 1,906 |
| Vistra Energy reorganization value of assets | $ | 15,161 |

***Consolidated Balance Sheet***

The adjustments to TCEH's October 3, 2016 consolidated balance sheet below include the impacts of the Plan of Reorganization and the adoption of fresh start reporting.

| | October 3, 2016 | | | | | | |
|---|---|---|---|---|---|---|---|
| | TCEH (Predecessor) (1) | Reorganization Adjustments (2) | | Fresh Start Adjustments | | Vistra Energy (Successor) |
| **ASSETS** | | | | | | |
| Current assets: | | | | | | |
| Cash and cash equivalents | $ 1,829 | $ (1,028) | (3) | $ — | | $ 801 |
| Restricted cash | 12 | 131 | (4) | — | | 143 |
| Trade accounts receivable — net | 750 | 4 | | — | | 754 |
| Advances to parents and affiliates of Predecessor | 78 | (78) | | — | | — |
| Inventories | 374 | — | | (86) | (17) | 288 |
| Commodity and other derivative contractual assets | 255 | — | | — | | 255 |
| Margin deposits related to commodity contracts | 42 | — | | — | | 42 |
| Other current assets | 47 | 17 | | 3 | | 67 |
| Total current assets | 3,387 | (954) | | (83) | | 2,350 |
| Restricted cash | 650 | — | | — | | 650 |
| Advance to parent and affiliates of Predecessor | 17 | (21) | | 4 | | — |
| Investments | 1,038 | 1 | | 9 | (18) | 1,048 |
| Property, plant and equipment — net | 10,359 | 53 | | (5,970) | (19) | 4,442 |
| Goodwill | 152 | — | | 1,755 | (27) | 1,907 |
| Identifiable intangible assets — net | 1,148 | 4 | | 2,256 | (20) | 3,408 |
| Commodity and other derivative contractual assets | 73 | — | | (14) | | 59 |
| Deferred income taxes | — | 320 | (5) | 730 | (21) | 1,050 |
| Other noncurrent assets | 51 | 38 | | 158 | (22) | 247 |
| Total assets | $ 16,875 | $ (559) | | $ (1,155) | | $ 15,161 |
| **LIABILITIES AND EQUITY** | | | | | | |
| Current liabilities: | | | | | | |
| Long-term debt due currently | $ 4 | $ 5 | | $ (1) | | $ 8 |
| Trade accounts payable | 402 | 145 | (6) | 3 | | 550 |
| Trade accounts and other payables to affiliates of Predecessor | 152 | (152) | (6) | — | | — |
| Commodity and other derivative contractual liabilities | 125 | — | | — | | 125 |
| Margin deposits related to commodity contracts | 64 | — | | — | | 64 |
| Accrued income taxes | 12 | 12 | | — | | 24 |
| Accrued taxes other than income | 119 | 4 | | — | | 123 |
| Accrued interest | 110 | (109) | (7) | — | | 1 |
| Other current liabilities | 243 | 170 | (8) | 5 | | 418 |
| Total current liabilities | 1,231 | 75 | | 7 | | 1,313 |

| | October 3, 2016 | | | | | |
|---|---|---|---|---|---|---|
| | TCEH (Predecessor) (1) | Reorganization Adjustments (2) | | Fresh Start Adjustments | | Vistra Energy (Successor) |
| Long-term debt, less amounts due currently | — | 3,476 | (9) | 151 | (23) | 3,627 |
| Borrowings under debtor-in-possession credit facilities | 3,387 | (3,387) | (9) | — | | — |
| Liabilities subject to compromise | 33,749 | (33,749) | (10) | — | | — |
| Commodity and other derivative contractual liabilities | 5 | — | | 3 | | 8 |
| Deferred income taxes | 256 | (256) | (11) | — | | — |
| Tax Receivable Agreement obligation | — | 574 | (12) | — | | 574 |
| Asset retirement obligations | 809 | — | | 854 | (24) | 1,663 |
| Other noncurrent liabilities and deferred credits | 1,018 | 117 | (13) | (900) | (25) | 235 |
| Total liabilities | 40,455 | (33,150) | | 115 | | 7,420 |
| Equity: | | | | | | |
| Common stock | — | 4 | (14) | — | | 4 |
| Additional paid-in-capital | — | 7,737 | (15) | — | | 7,737 |
| Accumulated other comprehensive income (loss) | (32) | 22 | | 10 | (26) | — |
| Predecessor membership interests | (23,548) | 24,828 | (16) | (1,280) | (26) | — |
| Total equity | (23,580) | 32,591 | | (1,270) | | 7,741 |
| Total liabilities and equity | $ 16,875 | $ (559) | | $ (1,155) | | $ 15,161 |

(1) Represents the consolidated balance sheet of TCEH as of October 3, 2016.

***Reorganization adjustments***

(2) Includes the addition of certain assets and liabilities associated with the Contributed EFH Entities. Also includes EFH Corp.'s contribution of liabilities associated with certain employee benefit plans to Vistra Energy.

(3) Net adjustments to cash, which represent distributions made or funding provided to an escrow account, classified as restricted cash, under the Plan of Reorganization, as follows:

| | |
|---|---|
| *Sources (uses):* | |
| Net proceeds from PrefCo preferred stock sale | $ 69 |
| Addition of cash balances from the Contributed EFH Debtors | 22 |
| Payments to TCEH first lien creditors, including adequate protection | (486) |
| Payment to TCEH unsecured creditors (including $73 million to escrow) | (502) |
| Payment of administrative claims to TCEH creditors | (53) |
| Payment of legal fees, professional fees and other costs (including $52 million to escrow) | (78) |
| Net use of cash | $ (1,028) |

(4) Increase in restricted cash primarily reflects amounts placed in escrow to satisfy certain secured claims, unsecured claims and professional fee obligations associated with the bankruptcy.

(5) Reflects the deferred income tax impact of the Plan of Reorganization implementation, including cancellation of debts and adjustment of tax-basis for certain assets of PrefCo that issued mandatorily redeemable preferred stock as part of the Spin-Off.

(6) Primarily reflects the reclassification of transmission and distribution service payables to Oncor from payables with affiliates to trade payables with third parties pursuant to the separation of Vistra Energy from EFH Corp. and payment of accrued professional fees and unsecured claimant obligations incurred in conjunction with Emergence.

(7) Primarily reflects the payment of accrued interest and adequate protection to the TCEH first lien creditors on the Effective Date.

(8) Primarily reflects the following:

- Reclassification of $82 million from LSTC related to secured and unsecured claims and $16 million in accrued professional fees from accounts payable to other current liabilities.

- Additional accruals for $23 million of change-in-control obligations and $26 million in success fees triggered by Emergence, $7 million in professional fees, and $28 million of accrued liabilities related to the Contributed EFH Entities.

- Payment of $12 million in professional fees.

(9) Reflects the conversion of the TCEH DIP Roll Facilities of $3.387 billion to the Vistra Operations Credit Facilities at Emergence, the issuance and sale of mandatorily redeemable preferred stock of PrefCo for $70 million , and the obligation related to a corporate office space lease contributed to Vistra Energy pursuant to the Plan of Reorganization. See Note 12 for additional details.

(10) Reflects the elimination of TCEH's liabilities subject to compromise pursuant to the Plan of Reorganization (see Note 5 ). Liabilities subject to compromise were settled as follows in accordance with the Plan of Reorganization:

| | | |
|---|---|---|
| Notes, loans and other debt | $ | 31,668 |
| Accrued interest on notes, loans and other debt | | 646 |
| Net liability under terminated TCEH interest rate swap and natural gas hedging agreements | | 1,243 |
| Trade accounts payable and other expected allowed claims | | 192 |
| Third-party liabilities subject to compromise | | 33,749 |
| LSTC from the Contributed EFH Entities | | 8 |
| Total liabilities subject to compromise | | 33,757 |
| Fair value of equity issued to TCEH first lien creditors | | (7,741) |
| TRA Rights issued to TCEH first lien creditors | | (574) |
| Cash distributed and accruals for TCEH first lien creditors | | (377) |
| Cash distributed for TCEH unsecured claims | | (502) |
| Cash distributed and accruals for TCEH administrative claims | | (60) |
| Settlement of affiliate balances | | (99) |
| Net liabilities of contributed entities and other items | | (60) |
| Gain on extinguishment of LSTC | $ | 24,344 |

(11) Reflects the deferred income tax impact of the Plan of Reorganization implementation, including cancellation of debts and adjustment of tax basis of certain assets of PrefCo.

(12) Reflects the estimated present value of the TRA obligation. See Note 9 for further discussion of the TRA obligation valuation assumptions.

(13) Primarily reflects the following:

- Addition of $122 million in liabilities primarily related to benefit plan obligations associated with a pension plan and a health and welfare plan assumed by Vistra Energy pursuant to the Plan of Reorganization. See Note 17 for further discussion of the benefit plan obligations.

- Payment of $7 million in settlements related to split life insurance costs with a prior affiliate entity.

(14) Reflects the issuance of approximately 427,500,000 shares of Vistra Energy common stock, par value of $0.01 per share, to the TCEH first lien creditors. See Note 14 .

(15) Reflects adjustments to present Vistra Energy equity value at approximately $7.741 billion based on a reconciliation from the $10.5 billion enterprise value described above under *Reorganization Value* as depicted below:

| | | |
|---|---|---|
| Enterprise value | $ | 10,500 |
| Vistra Operations Credit Facility – Initial Term Loan B Facility | | (2,871) |
| Vistra Operations Credit Facility – Term Loan C Facility | | (655) |
| Accrual for post-Emergence claims satisfaction | | (181) |
| Tax Receivable Agreement obligation | | (574) |
| Preferred stock of PrefCo | | (70) |
| Other items | | (2) |
| Cash and cash equivalents | | 801 |
| Restricted cash | | 793 |
| Equity value at Emergence | $ | 7,741 |
| Common stock at par value | $ | 4 |
| Additional paid-in capital | | 7,737 |
| Equity value | $ | 7,741 |
| Shares outstanding at October 3, 2016 (in millions) | | 427.5 |
| Per share value | $ | 18.11 |

(16) Membership Interest impact of Plan of Reorganization are shown below:

| | | |
|---|---|---|
| Gain on extinguishment of LSTC | $ | 24,344 |
| Elimination of accumulated other comprehensive income | | (22) |
| Change in control payments | | (23) |
| Professional fees | | (33) |
| Other items | | (14) |
| Pretax gain on reorganization adjustments (Note 5) | | 24,252 |
| Deferred tax impact of the Plan of Reorganization and Spin-off | | 576 |
| Total impact to membership interests | $ | 24,828 |

***Fresh start adjustments***

(17) Reflects the reduction of inventory to fair value, including (1) adjustment of fuel inventory to current market prices, and (2) an adjustment to the fair value of materials and supplies inventory primarily used in our lignite/coal-fueled generation assets and related mining operations.

(18) Reflects the $12 million increase in the fair value of certain real property assets and $3 million reduction of the fair value for other investments.

(19) Reflects the change in fair value of property, plant and equipment related primarily to generation and mining assets as detailed below:

| **Property, Plant and Equipment** | | **Adjustment** | | **Fair Value** |
|---|---|---|---|---|
| Generation plants and mining assets | $ | (6,057) | $ | 3,698 |
| Land | | 140 | | 490 |
| Nuclear Fuel | | (23) | | 157 |
| Other equipment | | (30) | | 97 |
| **Total** | $ | (5,970) | $ | 4,442 |

We engaged a third-party valuation specialist to assist in preparing the values for our property, plant and equipment. For our generation plants and related mining assets, an income approach was utilized in valuing those assets based on discounted cash flow models that forecast the cash flows of the related assets over their respective useful lives. Significant estimates and assumptions utilized in those models include (1) long-term wholesale power price forecasts, (2) fuel cost forecasts, (3) expected generation volumes based on prevailing forecasts and expected maintenance outages, (4) operations and maintenance costs, (5) capital expenditure forecasts and (6) risk adjusted discount rates based on the cash flows produced by the specific generation asset. The fair value of the generation plants and mining assets is based upon Level 3 inputs utilized in the income approach.

The fair value estimates for land and nuclear fuel utilized the market approach, which included utilizing recent comparable sales information and current market conditions for similarly situated land. Nuclear fuel values were determined by utilizing market pricing information for uranium. The fair value of land and nuclear fuel are based upon Level 3 inputs.

(20) Reflects the adjustment in fair value of $2.256 billion to identifiable intangible assets, including $1.636 billion increase related to retail customer relationships, $270 million increase related to the retail trade name, $190 million increase related to an electricity supply contract, $164 million increase related to retail and wholesale contracts and $4 million decrease related to other intangible assets (see Note 7 ).

Also reflects the reduction of fair value of $476 million to identifiable intangible liabilities, including a reduction of $525 million related to an electricity supply contract and an increase of $49 million to wholesale contracts.

(21) Reflects the deferred income tax impact of fresh-start adjustments to property, plant, and equipment, inventory, intangibles and debt issuance costs.

(22) Primarily reflects the following:

- Addition of $197 million regulatory asset related to the deficiency of the nuclear decommissioning trust investment as compared to the nuclear generation plant retirement obligation. Pursuant to Texas regulatory provisions, the trust fund for decommissioning our nuclear generation facility is funded by a fee surcharge billed to REPs by Oncor, as a collection agent, and remitted monthly to Vistra Energy.

- Adjustment to remove $26 million of unamortized debt issuance costs to reflect the Vistra Operations Credit Facilities at fair market value.

(23) Reflects the increase in fair value of the Vistra Operations Credit Facilities in the amount of $151 million based on the quoted market prices of the facilities.

(24) Increase in fair value of asset retirement obligation related to the plant retirement, mining and reclamation retirement, and coal combustion residuals. See Note 21 for further discussion of our asset retirement obligations.

(25) Reflects the following:

- Reduction in fair value of unfavorable contracts related to wholesale contracts and a portion of an electricity supply contract in the amount of $476 million . See footnote (20) above for further detail.

- Reduction of $465 million related to reduction in liability that represented excess amounts in the nuclear decommissioning trust above the carrying value of the asset retirement obligation related to our nuclear generation plant decommissioning.

- Increase in fair value of obligations related to leased property in the amount of $29 million .

- Increase in fair value of Pension and OPEB obligations in the amount of $12 million .

(26) Reflects the extinguishment of Predecessor membership interest and accumulated other comprehensive loss per the Plan of Reorganization.

(27) Reflects increase in goodwill balance to present final goodwill as the reorganization value in excess of the identifiable tangible assets, intangible assets, and liabilities at Emergence.

| | | |
|---|---|---|
| Business enterprise value | $ | 10,500 |
| Add: Fair value of liabilities excluded from enterprise value | | 3,030 |
| Less: Fair value of tangible assets | | (8,215) |
| Less: Fair value of identified intangible assets | | (3,408) |
| Vistra Energy goodwill | $ | 1,907 |

## 7. GOODWILL AND IDENTIFIABLE INTANGIBLE ASSETS

***Goodwill***

The carrying value of goodwill totaled $1.907 billion at both December 31, 2017 and 2016 . The goodwill arose in connection with our application of fresh start reporting at Emergence and was allocated entirely to the Retail Electricity reporting unit (see Note 1 ). Of the goodwill recorded at Emergence, $1.686 billion is deductible for tax purposes over 15 years on a straight-line basis.

Goodwill and intangible assets with indefinite useful lives are required to be evaluated for impairment at least annually or whenever events or changes in circumstances indicate an impairment may exist. As of the Effective Date, we have selected October 1 as our annual goodwill test date. On the most recent goodwill testing date, we applied qualitative factors and determined that it was more likely than not that the fair value of the Retail Electricity reporting unit exceeded its carrying value at October 1, 2017. Significant qualitative factors evaluated included reporting unit financial performance and market multiples, cost factors, customer attrition, interest rates and changes in reporting unit book value.

***Predecessor Goodwill Impairments***

During the fourth quarter of 2015, our Predecessor performed a goodwill impairment analysis as of its annual testing date of December 1. Further, during the fourth quarter of 2015, there were significant declines in the market values of several similarly situated peer companies with publicly traded equity, which indicated our Predecessor's overall enterprise value should be reassessed. Our Predecessor's testing resulted in an impairment of goodwill of $800 million at December 1, 2015.

During the first nine months of 2015, our Predecessor experienced impairment indicators related to decreases in forward wholesale electricity prices when compared to those prices reflected in its December 1, 2014 goodwill impairment testing analysis. As a result, the likelihood of goodwill impairments had increased, and our Predecessor initiated further testing of goodwill. Our Predecessor's testing of goodwill for impairment during the first nine months of 2015 resulted in impairment charges totaling $1.4 billion .

***Identifiable Intangible Assets***

Identifiable intangible assets are comprised of the following:

| | December 31, 2017 | | | December 31, 2016 | | |
|---|---|---|---|---|---|---|
| **Identifiable Intangible Asset** | **Gross Carrying Amount** | **Accumulated Amortization** | **Net** | **Gross Carrying Amount** | **Accumulated Amortization** | **Net** |
| Retail customer relationship | $ 1,648 | $ 572 | $ 1,076 | $ 1,648 | $ 152 | $ 1,496 |
| Software and other technology-related assets | 183 | 47 | 136 | 147 | 9 | 138 |
| Electricity supply contract (a) | — | — | — | 190 | 2 | 188 |
| Retail and wholesale contracts | 154 | 87 | 67 | 164 | 38 | 126 |
| Other identifiable intangible assets (b) | 33 | 11 | 22 | 30 | 2 | 28 |
| Total identifiable intangible assets subject to amortization | $ 2,018 | $ 717 | 1,301 | $ 2,179 | $ 203 | 1,976 |
| Retail trade names (not subject to amortization) | | | 1,225 | | | 1,225 |
| Mineral interests (not currently subject to amortization) | | | 4 | | | 4 |
| Total identifiable intangible assets | | | $ 2,530 | | | $ 3,205 |

(a) Contract terminated in October 2017. See Note 4 .
(b) Includes mining development costs and environmental allowances and credits.

Amortization expense related to finite-lived identifiable intangible assets (including the classification in the statements of consolidated income (loss)) consisted of:

| | | | Successor | | Predecessor | |
|---|---|---|---|---|---|---|
| **Identifiable Intangible Asset** | **Statements of Consolidated Income (Loss) Line** | **Remaining useful lives at December 31, 2017 (weighted average in years)** | **Year Ended December 31, 2017** | **Period from October 3, 2016 through December 31, 2016** | **Period from January 1, 2016 through October 2, 2016** | **Year Ended December 31, 2015** |
| Retail customer relationship | Depreciation and amortization | 4 | $ 420 | $ 152 | $ 9 | $ 17 |
| Software and other technology-related assets | Depreciation and amortization | 3 | 38 | 9 | 44 | 60 |
| Electricity supply contract | Operating revenues | 0 | 6 | 2 | — | — |
| Retail and wholesale contracts | Operating revenues/fuel, purchased power costs and delivery fees | 3 | 59 | 38 | — | — |
| Other identifiable intangible assets | Operating revenues/fuel, purchased power costs and delivery fees/depreciation and amortization | 4 | 9 | 2 | 6 | 30 |
| Total amortization expense (a) | | | $ 532 | $ 203 | $ 59 | $ 107 |

(a) Amounts recorded in depreciation and amortization totaled $463 million , $162 million , $58 million and $85 million for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively.

Following is a description of the separately identifiable intangible assets. In connection with fresh start reporting (see Note 6 ), the intangible assets were adjusted based on their estimated fair value as of the Effective Date, based on observable prices or estimates of fair value using valuation models.

- *Retail customer relationship* – Retail customer relationship intangible asset represents the fair value of our non-contracted retail customer base, including residential and business customers, and is being amortized using an accelerated method based on historical customer attrition rates and reflecting the expected pattern in which economic benefits are realized over their estimated useful life.

- *Retail trade names* – Our retail trade name intangible asset represents the fair value of the TXU Energy ™ and 4Change Energy ™ trade names, and was determined to be an indefinite-lived asset not subject to amortization. This intangible asset is evaluated for impairment at least annually in accordance with accounting guidance related to goodwill and other indefinite-lived intangible assets. Significant assumptions included within the development of the fair value estimate include TXU Energy's and 4Change Energy's estimated gross margins for future periods and implied royalty rates. On the most recent testing date, we determined that it was more likely than not that the fair value of our retail trade name intangible asset exceeded its carrying value at October 1, 2017.

- *Electricity supply contract* – The electricity supply contract represents a long-term fixed-price supply contract for the sale of electricity from one of our generation facilities that was measured at fair value at Emergence. The value of this contract under our Predecessor was recorded as an unfavorable liability due to prevailing market prices of electricity when the contract was established in 2007. Significant assumptions included in the fair value measurement for this contract include long-term wholesale electricity price forecasts and operating cost forecasts for the respective generation facility. This contract was terminated in October 2017. See Note 4 .

- *Retail and wholesale contracts* – These intangible assets represent the favorable value of various retail and wholesale contracts (both purchase and sale contracts) that were measured at fair value by utilizing prevailing market prices for commodities or services compared to the fixed prices contained in these agreements. The value of these contracts is being amortized using a method that is based on the monthly value of each contract measured at Emergence.

***Estimated Amortization of Identifiable Intangible Assets***

As of December 31, 2017 , the estimated aggregate amortization expense of identifiable intangible assets for each of the next five fiscal years is as shown below.

| Year | Estimated Amortization Expense | |
|---|---|---|
| 2018 | $ | 367 |
| 2019 | $ | 268 |
| 2020 | $ | 191 |
| 2021 | $ | 142 |
| 2022 | $ | 4 |

## *Predecessor I ntangible Impairments*

The impairments of generation facilities in 2015 (see Note 4 ) resulted in the impairment of the $SO_2$ allowances under the Clean Air Act's acid rain cap-and-trade program that are associated with those facilities to the extent they are not projected to be used at other sites. The fair market values of the $SO_2$ allowances were estimated to be de minimis based on Level 3 fair value estimates (see Note 15 ). Our Predecessor also impaired certain of its $SO_2$ allowances under the Cross-State Air Pollution Rule (CSAPR) related to the impaired generation facilities. Accordingly, in the year ended December 31, 2015, our Predecessor recorded noncash impairment charges of $55 million (before deferred income tax benefit) in other deductions (see Note 21 ) related to its existing environmental allowances and credits intangible asset. $SO_2$ emission allowances granted under the acid rain cap-and-trade program were recorded as intangible assets at fair value in connection with purchase accounting in 2007. Additionally, the impairments of generation and related mining facilities in 2015 resulted in recording noncash impairment charges of $19 million (before deferred income tax benefit) in other deductions (see Note 21 ) related to mine development costs (included in other identifiable intangible assets in the table above) at the facilities.

During 2015, our Predecessor determined that certain intangible assets related to favorable power purchase contracts should be evaluated for impairment. That conclusion was based on declines in wholesale electricity prices in ERCOT experienced during 2015. The fair value measurement was based on a discounted cash flow analysis of the contracts that compared the contractual price and terms of the contract to forecasted wholesale electricity and renewable energy credit (REC) prices in ERCOT. As a result of the analysis, our Predecessor recorded a noncash impairment charge of $8 million (before deferred income tax benefit) in other deductions (see Note 21 ).

## 8. INCOME TAXES

Subsequent to the Effective Date, the TCEH Debtors and the Contributed EFH Debtors are included in Vistra Energy's consolidated federal income tax return and are no longer included in the consolidated federal income tax return of EFH Corp.

Prior to the Effective Date, EFH Corp. was the corporate parent of the EFH Corp. consolidated group, while TCEH and the Contributed EFH Debtors were classified as disregarded entities for U.S. federal income tax purposes. For the 2016 tax year (through the period until the Effective Date) EFH Corp. filed a U.S. federal income tax return in October 2017 that included the results of TCEH and the EFH Contributed Debtors. Pursuant to applicable U.S. Treasury regulations and published guidance of the IRS, corporations that are members of a consolidated group have joint and several liability for the taxes of such group.

Prior to the Effective Date, EFH Corp. and certain of its subsidiaries (including TCEH and the Contributed EFH Debtors) were parties to a Federal and State Income Tax Allocation Agreement, which provided, among other things, that any corporate member or disregarded entity in the EFH Corp. group was required to make payments to EFH Corp. in an amount calculated to approximate the amount of tax liability such entity would have owed if it filed a separate corporate tax return. Pursuant to the Plan of Reorganization, the TCEH Debtors and the Contributed EFH Debtors rejected this agreement on the Effective Date. See Note 5 for a discussion of the Tax Matters Agreement that was entered into on the Effective Date between EFH Corp. and Vistra Energy. Additionally, since the date of the Settlement Agreement, no further cash payments among the Debtors were made in respect of federal income taxes. The Settlement Agreement did not alter the allocation and payment for state income taxes, which continued to be settled prior to the Effective Date.

***Income Tax Expense (Benefit)***

The components of our income tax expense (benefit) are as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Current: | | | | |
| U.S. Federal | $ 72 | $ — | $ (6) | $ (17) |
| State | 14 | 6 | 9 | 21 |
| Total current | 86 | 6 | 3 | 4 |
| Deferred: | | | | |
| U.S. Federal | 417 | (75) | (1,234) | (811) |
| State | 1 | (1) | (36) | (72) |
| Total deferred | 418 | (76) | (1,270) | (883) |
| Total | $ 504 | $ (70) | $ (1,267) | $ (879) |

Reconciliation of income taxes computed at the U.S. federal statutory rate to income tax expense (benefit) recorded:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Income (loss) before income taxes | $ 250 | $ (233) | $ 21,584 | $ (5,556) |
| Income taxes at the U.S. federal statutory rate of 35% | 88 | (82) | 7,554 | (1,945) |
| Nondeductible TRA accretion | (80) | 5 | — | — |
| Texas margin tax, net of federal benefit | 13 | 3 | (21) | — |
| Impacts of tax reform legislation on deferred taxes | 451 | — | — | — |
| Effects of Tax Matters Agreement and tax-free spin-off transaction | 19 | — | — | — |
| Nondeductible debt restructuring costs | — | 2 | 38 | 64 |
| Nondeductible interest expense | — | — | 12 | 21 |
| Nontaxable gain on extinguishment of LSTC | — | — | (8,593) | — |
| Valuation allowance | — | — | (210) | 210 |
| Nondeductible goodwill impairment | — | — | — | 770 |
| Lignite depletion allowance | — | — | — | (8) |
| Interest accrued for uncertain tax positions, net of tax | — | — | — | (2) |
| Other | 13 | 2 | (47) | 11 |
| Income tax expense (benefit) | $ 504 | $ (70) | $ (1,267) | $ (879) |
| Effective tax rate | 201.6% | 30.0% | (5.9)% | 15.8% |

***Deferred Income Tax Balances***

Deferred income taxes provided for temporary differences based on tax laws in effect at December 31, 2017 and 2016 are as follows:

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| **Noncurrent Deferred Income Tax Assets** | | |
| Net operating loss (NOL) carryforwards | $ — | $ 8 |
| Property, plant and equipment | 520 | 943 |
| Intangible assets | 81 | 29 |
| Long-term debt | 20 | 52 |
| Employee benefit obligations | 56 | 84 |
| Commodity contracts and interest rate swaps | 25 | — |
| Other | 8 | 6 |
| Total deferred tax assets | $ 710 | $ 1,122 |

At December 31, 2017 , we had total deferred tax assets of approximately $710 million that were substantially comprised of book and tax basis differences related to our generation and mining property, plant and equipment. Our deferred tax assets were significantly impacted by the TCJA that was signed into law in December 2017, which reduced the overall federal corporate rate from 35% to 21% . This rate change decreased our overall deferred tax asset balance by approximately $451 million . As of December 31, 2017 , we assessed the need for a valuation allowance related to our deferred tax asset and considered both positive and negative evidence related to the likelihood of realization of the deferred tax assets. In connection with that analysis, we concluded that it is more likely than not that the deferred tax assets would be fully utilized by future taxable income, and thus, no valuation allowance was recognized.

At December 31, 2017 , we had no net operating loss (NOL) carryforwards for federal income tax purposes. At December 31, 2017 , we had no alternative minimum tax (AMT) credit carryforwards available.

The income tax effects of the components included in accumulated other comprehensive income totaled a net deferred tax asset of $6 million at December 31, 2017 and a net deferred tax liability of $3 million at December 31, 2016.

***Liability for Uncertain Tax Positions***

Accounting guidance related to uncertain tax positions requires that all tax positions subject to uncertainty be reviewed and assessed with recognition and measurement of the tax benefit based on a "more-likely-than-not" standard with respect to the ultimate outcome, regardless of whether this assessment is favorable or unfavorable.

*Successor* — Vistra Energy and its subsidiaries file income tax returns in U.S. federal and state jurisdictions and are expected to be subject to examinations by the IRS and other taxing authorities. Vistra Energy has limited operational history and filed its first federal tax return in October 2017. Vistra Energy is not currently under audit for any period, and we had no uncertain tax positions at both December 31, 2017 and 2016 .

*Predecessor* — EFH Corp. and its subsidiaries file or have filed income tax returns in U.S. Federal, state and foreign jurisdictions and are subject to examinations by the IRS and other taxing authorities. Examinations of income tax returns filed by EFH Corp. and any of its subsidiaries for the years ending prior to January 1, 2015 are complete. The IRS chose not to audit the tax return filed by EFH Corp. for the 2015 tax year. EFH Corp. filed a request for prompt determination of its 2016 tax return with the IRS in October 2017, and such return was accepted for expedited review in December 2017. As a result, the IRS audit of EFH Corp.'s 2016 tax return is currently in progress and is expected to conclude by April 2018. Texas franchise and margin tax return examinations have been completed.

In September 2016, EFH Corp. entered into a settlement agreement with the Texas Comptroller of Public Accounts (Comptroller) whereby the Comptroller agreed to release all claims and liabilities related to the EFH Corp. consolidated group's state taxes, including sales tax, gross receipts utility tax, franchise tax and direct pay tax, through the agreement date, in exchange for a release of all refund claims and a one-time payment of $12 million . This settlement was entered and approved by the Bankruptcy Court in September 2016. As a result of the settlement, our Predecessor reduced the liability for uncertain tax positions by $27 million .

In July 2016, EFH Corp. executed a Revenue Agent Report (RAR) with the IRS for the 2010 through 2013 tax years. As a result of the RAR, our Predecessor reduced the liability for uncertain tax positions by $1 million , resulting in a reclassification to the accumulated deferred income tax liability. Total cash payment to be assessed by the IRS for tax years 2010 through 2013, but not expected to be paid during the pendency of the Chapter 11 Cases of the EFH Debtors, is approximately $15 million , plus any interest that may be assessed.

In March 2016, EFH Corp. signed a RAR with the IRS for the 2014 tax year. No financial statement impacts resulted from the signing of the 2014 RAR.

In June 2015, EFH Corp. signed a RAR with the IRS for the 2008 and 2009 tax years. The Bankruptcy Court approved EFH Corp.'s signing of the RAR in July 2015. As a result of EFH Corp. signing this RAR, our Predecessor reduced the liability for uncertain tax positions by $22 million , resulting in a $18 million increase in noncurrent inter-company tax payable to EFH Corp., a $2 million reclassification to the accumulated deferred income tax liability and the recording of a $2 million income tax benefit. Total cash payment to be assessed by the IRS for tax years 2008 and 2009, but not paid during the pendency of the Chapter 11 Cases of the EFH Debtors, is approximately $15 million , plus any interest that may be assessed.

Our Predecessor classified interest and penalties related to uncertain tax positions as current income tax expense. Ongoing accruals of interest after the IRS settlements were not material in 2015.

Noncurrent liabilities of our Predecessor included a total of $4 million in accrued interest at December 31, 2015. The federal income tax benefit on the interest accrued on uncertain tax positions was recorded as accumulated deferred income taxes.

The following table summarizes the changes to the uncertain tax positions, reported in other noncurrent liabilities in the consolidated balance sheets, during the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively:

| | Predecessor | |
|---|---|---|
| | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Balance at beginning of period, excluding interest and penalties | $ 36 | $ 65 |
| Reductions based on tax positions related to prior years | (1) | (11) |
| Settlements with taxing authorities | (35) | (18) |
| Balance at end of period, excluding interest and penalties | $ — | $ 36 |

***Tax Matters Agreement***

On the Effective Date, we entered into the Tax Matters Agreement with EFH Corp. whereby the parties have agreed to take certain actions and refrain from taking certain actions in order to preserve the intended tax treatment of the Spin-Off and to indemnify the other parties to the extent a breach of such agreement results in additional taxes to the other parties.

Among other things, the Tax Matters Agreement allocates the responsibility for taxes for periods prior to the Spin-Off between EFH Corp. and us. For periods prior to the Spin-Off: (a) Vistra Energy is generally required to reimburse EFH Corp. with respect to any taxes paid by EFH Corp. that are attributable to us and (b) EFH Corp. is generally required to reimburse us with respect to any taxes paid by us that are attributable to EFH Corp.

We are also required to indemnify EFH Corp. against taxes, under certain circumstance, if the IRS or another taxing authority successfully challenges the amount of gain relating to the PrefCo Preferred Stock Sale or the amount or allowance of EFH Corp.'s net operating loss deductions.

Subject to certain exceptions, the Tax Matters Agreement prohibits us from taking certain actions that could reasonably be expected to undermine the intended tax treatment of the Spin-Off or to jeopardize the conclusions of the private letter ruling we obtained from the IRS or opinions of counsel received by us or EFH Corp., in each case, in connection with the Spin-Off. Certain of these restrictions apply for two years after the Spin-Off.

Under the Tax Matters Agreement, we may engage in an otherwise restricted action if (a) we obtain written consent from EFH Corp., (b) such action or transaction is described in or otherwise consistent with the facts in the private letter ruling we obtained from the IRS in connection with the Spin-Off, (c) we obtain a supplemental private letter ruling from the IRS, or (d) we obtain an unqualified opinion of a nationally recognized law or accounting firm that is reasonably acceptable to EFH Corp. that the action will not affect the intended tax treatment of the Spin-Off.

## 9. TAX RECEIVABLE AGREEMENT OBLIGATION

On the Effective Date, Vistra Energy entered into a tax receivable agreement (the TRA) with a transfer agent on behalf of certain former first lien creditors of TCEH. The TRA generally provides for the payment by us to holders of TRA Rights of 85% of the amount of cash savings, if any, in U.S. federal and state income tax that we realize in periods after Emergence as a result of (a) certain transactions consummated pursuant to the Plan of Reorganization (including the step-up in tax basis in our assets resulting from the PrefCo Preferred Stock Sale), (b) the tax basis of all assets acquired in connection with the Lamar and Forney Acquisition in April 2016 (see Note 3 ) and (c) tax benefits related to imputed interest deemed to be paid by us as a result of payments under the TRA, plus interest accruing from the due date of the applicable tax return.

Pursuant to the TRA, we issued the TRA Rights for the benefit of the first lien secured creditors of our Predecessor entitled to receive such TRA Rights under the Plan. Such TRA Rights are subject to various transfer restrictions described in the TRA and are entitled to certain registration rights more fully described in the Registration Rights Agreement (see Note 19 ).

During the year ended December 31, 2017 , we recorded reductions to the carrying value of the TRA obligation totaling approximately $295 million . The largest driver in the reduction to the TRA obligation carrying value primarily resulted from a change in the corporate tax rate from 35% to 21% related to tax reform legislation, which reduced the total expected undiscounted payments under the TRA from $2.1 billion to $1.2 billion . The value of the TRA obligation was also impacted by changes in the estimated timing of TRA payments resulting from changes in certain tax assumptions including (a) the impacts of Luminant's plan to retire its Monticello, Sandow 4, Sandow 5 and Big Brown generation plants and the impacts of the Alcoa settlement (see Note 4 ), (b) investment tax credits we expect to receive related to the Upton solar development project (see Note 3 ), (c) assets acquired in the Odessa Acquisition (see Note 3 ) and (d) the impacts of other forecasted tax amounts.

The following table summarizes the changes to the TRA obligation, reported as other current liabilities and Tax Receivable Agreement obligation in our consolidated balance sheets, for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016:

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| TRA obligation at the beginning of the period | $ 596 | $ 574 |
| Accretion expense | 82 | 22 |
| Payments | (26) | — |
| Revaluation due to tax reform legislation | (233) | — |
| Changes in tax assumptions impacting timing of payments | (62) | — |
| TRA obligation at the end of the period | 357 | 596 |
| Less amounts due currently | (24) | — |
| Noncurrent TRA obligation at the end of the period | $ 333 | $ 596 |

As of December 31, 2017 , the estimated carrying value of the TRA obligation totaled $357 million , which represents the discounted amount of projected payments under the TRA. The projected payments are based on certain assumptions, including but not limited to (a) the federal corporate income tax rate of 21% and (b) estimates of our taxable income in the current and future years. Our taxable income takes into consideration the current federal tax code and reflects our current estimates of future results of the business. Our estimates of taxable income did not consider the impact of the Merger. These assumptions are subject to change, and those changes could have a material impact on the carrying value of the TRA obligation. The aggregate amount of undiscounted payments under the TRA is estimated to be approximately $1.2 billion , with more than half of such amount expected to be attributable to the first 15 tax years following Emergence, and the final payment expected to be made approximately 40 years following Emergence (assuming that the TRA is not terminated earlier pursuant to its terms).

The carrying value of the obligation is being accreted to the amount of the gross expected obligation using the effective interest method. Changes in the amount of this obligation resulting from changes to either the timing or amount of TRA payments are recognized in the period of change and measured using the discount rate inherent in the initial fair value of the obligation. During the year ended December 31, 2017 , the Impacts of Tax Receivable Agreement on the statement of consolidated income (loss) totaled $213 million , which represents the reduction to the carrying value of the TRA obligation discussed above and payments of $26 million net of accretion expense totaling $82 million . During the period from October 3, 2016 through December 31, 2016, the Impacts of the Tax Receivable Agreement represents accretion expense totaling $22 million .

Under the Internal Revenue Code, a corporation's ability to utilize certain tax attributes, including depreciation, may be limited following an ownership change if the corporation's overall asset tax basis exceeds the overall fair market value of its assets (after making certain adjustments). The Spin-Off resulted in an ownership change and it is expected that the overall tax basis of our assets may have exceeded the overall fair market value of our assets at such time. As a result, there may be a limitation on our ability to claim a portion of our depreciation deductions for a five-year period. This limitation could have a material impact on our tax liabilities and on our obligations under the TRA Rights. In addition, any future ownership change of Vistra Energy following Emergence could likewise result in additional limitations on our ability to use certain tax attributes existing at the time of any such ownership change and have an impact on our tax liabilities and on our obligations with respect to the TRA Rights under the TRA.

## 10. INTEREST EXPENSE AND RELATED CHARGES

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Interest paid/accrued post-Emergence | $ 213 | $ 51 | $ — | $ — |
| Interest paid/accrued on debtor-in-possession financing | — | — | 76 | 63 |
| Adequate protection amounts paid/accrued | — | — | 977 | 1,233 |
| Unrealized mark-to-market net (gains) losses on interest rate swaps | (29) | 11 | — | — |
| Capitalized interest | (7) | (3) | (9) | (11) |
| Other | 16 | 1 | 5 | 4 |
| Total interest expense and related charges | $ 193 | $ 60 | $ 1,049 | $ 1,289 |

***Successor***

Interest expense and related charges totaled $193 million and $60 million for the Successor for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, respectively. The weighted average interest rate applicable to the Vistra Operations Credit Facilities, taking into account the interest rate swaps discussed in Note 12 , was 4.38% and 4.78% at December 31, 2017 and 2016 , respectively.

***Predecessor***

Interest expense for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 reflects interest paid and accrued on debtor-in-possession financing (see Note 12 ) and adequate protection amounts paid and accrued, as approved by the Bankruptcy Court in June 2014 for the benefit of secured creditors in exchange for their consent to the senior secured, super-priority liens contained in the DIP Facility. The interest rate applicable to the adequate protection amounts paid/accrued for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 was 4.95% and 4.69% , respectively.

The Bankruptcy Code generally restricts payment of interest on pre-petition debt, subject to certain exceptions. Other than amounts ordered or approved by the Bankruptcy Court, effective on the Petition Date, our Predecessor discontinued recording interest expense on outstanding pre-petition debt classified as LSTC. The table below shows contractual interest amounts, which are amounts due under the contractual terms of the outstanding debt, including debt subject to compromise during the Chapter 11 Cases. Interest expense reported in our statements of consolidated income (loss) does not include contractual interest on pre-petition debt classified as LSTC totaling $640 million and $897 million for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively, which had been stayed by the Bankruptcy Court effective on the Petition Date. Adequate protection amounts paid/accrued presented below excludes interest paid/accrued on TCEH first-lien interest rate and commodity hedge claims totaling $47 million and $60 million for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively, as such amounts are not included in contractual interest amounts below.

| | Predecessor | |
|---|---|---|
| | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Contractual interest on debt classified as LSTC | $ 1,570 | $ 2,070 |
| Adequate protection amounts paid/accrued | 930 | 1,173 |
| Contractual interest on debt classified as LSTC not paid/accrued | $ 640 | $ 897 |

## 11. EARNINGS PER SHARE

Basic earnings per share available to common shareholders are based on the weighted average number of common shares outstanding during the period. Diluted earnings per share is calculated using the treasury stock method and includes the effect of all potential issuances of common shares under stock-based incentive compensation arrangements.

| | Successor | | | | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, 2017 | | | Period from October 3, 2016 through December 31, 2016 | | |
| | Net Loss | Shares | Per Share Amount | Net Loss | Shares | Per Share Amount |
| Net loss available for common stock — basic | $ (254) | 427,761,460 | $ (0.59) | $ (163) | 427,560,620 | $ (0.38) |
| Net loss available for common stock — diluted | $ (254) | 427,761,460 | $ (0.59) | $ (163) | 427,560,620 | $ (0.38) |

For the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, stock-based incentive compensation plan awards totaling 3,642,844 and 7,332,789 shares, respectively, were excluded from the calculation of diluted earnings per share because the effect would have been antidilutive.

## 12. LONG-TERM DEBT

### *Successor*

Amounts in the table below represent the categories of long-term debt obligations incurred by the Successor.

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| Vistra Operations Credit Facilities (a) | $ 4,323 | $ 4,515 |
| Mandatorily redeemable subsidiary preferred stock (b) | 70 | 70 |
| 8.82% Building Financing due semiannually through February 11, 2022 (c) | 30 | 36 |
| Capital lease obligations | — | 2 |
| Total long-term debt including amounts due currently | 4,423 | 4,623 |
| Less amounts due currently | (44) | (46) |
| Total long-term debt less amounts due currently | $ 4,379 | $ 4,577 |

____________

(a) At December 31, 2017 , borrowings under the Vistra Operations Credit Facilities in our consolidated balance sheet include debt premiums of $21 million , debt discounts of $2 million and debt issuance costs of $7 million . At December 31, 2016 , borrowings under the Vistra Operations Credit Facilities in our consolidated balance sheet include debt premiums of $25 million , debt discounts of $2 million and debt issuance costs of $8 million .

(b) Shares of mandatorily redeemable preferred stock in PrefCo issued as part of the spin-off of Vistra Energy from EFH Corp. (see Note 5 ). This subsidiary preferred stock is accounted for as a debt instrument under relevant accounting guidance.

(c) Obligation related to a corporate office space capital lease transferred to Vistra Energy pursuant to the Plan of Reorganization. This obligation will be funded by amounts held in an escrow account that is reflected in other noncurrent assets in our consolidated balance sheets.

*Vistra Operations Credit Facilities* — At December 31, 2017 , the Vistra Operations Credit Facilities consisted of up to $5.171 billion in senior secured, first lien revolving credit commitments and outstanding term loans, consisting of revolving credit commitments of up to $860 million (Revolving Credit Facility), initial term loans in the amount totaling $2.821 billion (Initial Term Loan B Facility), incremental term loans totaling $990 million (Incremental Term Loan B Facility, and together with the Initial Term Loan B Facility, the Term Loan B Facility) and letter of credit term loans totaling $500 million (Term Loan C Facility). Principal amounts repaid on the Term Loan B Facility and the Term Loan C Facility cannot be reborrowed. Also in December 2017, although the size of the Revolving Credit Facility did not change, the letter of credit sub-facility of the Revolving Credit Facility was increased from $600 million to $715 million .

The Vistra Operations Credit Facilities and related available capacity at December 31, 2017 are presented below.

| | | December 31, 2017 | | |
|---|---|---|---|---|
| Vistra Operations Credit Facilities | Maturity Date | Facility Limit | Cash Borrowings | Available Capacity |
| Revolving Credit Facility (a) | August 4, 2021 | $ 860 | $ — | $ 834 |
| Initial Term Loan B Facility (b)(c) | August 4, 2023 | 2,850 | 2,821 | — |
| Incremental Term Loan B Facility (c) | December 14, 2023 | 1,000 | 990 | — |
| Term Loan C Facility (d) | August 4, 2023 | 650 | 500 | 7 |
| Total Vistra Operations Credit Facilities | | $ 5,360 | $ 4,311 | $ 841 |

(a) Facility to be used for general corporate purposes. Facility includes a $715 million letter of credit sub-facility, of which $26 million of letters of credit were outstanding at December 31, 2017 .

(b) Facility used to repay all amounts outstanding under our Predecessor's DIP Facility and issuance costs for the DIP Roll Facilities, with the remaining balance used for general corporate purposes.

(c) Cash borrowings under the Term Loan B Facility reflect required scheduled quarterly payment in annual amount equal to 1% of the original principal amount with the balance paid at maturity. Amounts paid cannot be reborrowed.

(d) Facility used for issuing letters of credit for general corporate purposes. Borrowings under this facility were funded to collateral accounts that are reported as restricted cash in our consolidated balance sheets. Cash borrowings reflect a $150 million principal reduction paid from restricted cash in December 2017. Amounts paid cannot be reborrowed. At December 31, 2017 , the restricted cash supported $493 million in letters of credit outstanding (see Note 21 ), leaving $7 million in available letter of credit capacity.

In February, August and December 2017, certain pricing terms for the Vistra Operations Credit Facility were amended. We accounted for these transactions as modifications of debt. At December 31, 2017 , cash borrowings under the Revolving Credit Facility bore interest based on applicable LIBOR rates, plus a fixed spread of 2.50% , and there were no outstanding borrowings. Letters of credit issued under the Revolving Credit Facility bore interest of 2.50% . Amounts borrowed under the Initial Term Loan B Facility and the Term Loan C Facility bore interest based on applicable LIBOR rates, subject to a 0.75% floor, plus a fixed spread of 2.50% . Amounts borrowed under the Incremental Term Loan B Facility bore interest based on applicable LIBOR rates, subject to a 0.75% floor, plus a fixed spread of 2.75% . At December 31, 2017 , the weighted average interest rate before taking into consideration interest rate swaps on outstanding borrowings was 4.02% , 4.20% and 3.83% under the Initial Term Loan B Facility, the Incremental Term Loan B Facility and the Term Loan C Facility, respectively. The Vistra Operations Credit Facilities also provide for certain additional fees payable to the agents and lenders, as well as availability fees payable with respect to any unused portions of the available Vistra Operations Credit Facilities.

In February 2018, certain pricing terms for the Vistra Operations Credit Facility were amended. Any amounts borrowed under the Revolving Credit Facility will bear interest based on applicable LIBOR rates plus 2.25% . Letters of credit issued under the Revolving Credit Facility will bear interest of 2.25% . Amounts borrowed under the Incremental Term Loan B Facility will bear interest based on applicable LIBOR rates plus 2.25% .

Obligations under the Vistra Operations Credit Facilities are secured by a lien covering substantially all of Vistra Operations' (and its subsidiaries') consolidated assets, rights and properties, subject to certain exceptions set forth in the Vistra Operations Credit Facilities.

The Vistra Operations Credit Facilities also permit certain hedging agreements to be secured on a pari passu basis with the Vistra Operations Credit Facilities in the event those hedging agreements met certain criteria set forth in the Vistra Operations Credit Facilities.

The Vistra Operations Credit Facilities provide for affirmative and negative covenants applicable to Vistra Operations (and its restricted subsidiaries), including affirmative covenants requiring it to provide financial and other information to the agents under the Vistra Operations Credit Facilities and to not change its lines of business, and negative covenants restricting Vistra Operations' (and its restricted subsidiaries') ability to incur additional indebtedness, make investments, dispose of assets, pay dividends, grant liens or take certain other actions, in each case except as permitted in the Vistra Operations Credit Facilities. Vistra Operations' ability to borrow under the Vistra Operations Credit Facilities is subject to the satisfaction of certain customary conditions precedent set forth therein.

The Vistra Operations Credit Facilities provide for certain customary events of default, including events of default resulting from non-payment of principal, interest or fees when due, material breaches of representations and warranties, material breaches of covenants in the Vistra Operations Credit Facilities or ancillary loan documents, cross-defaults under other agreements or instruments and the entry of material judgments against Vistra Operations. Solely with respect to the Revolving Credit Facility, and solely during a compliance period (which, in general, is applicable when the aggregate revolving borrowings and issued revolving letters of credit (in excess of $100 million ) exceed 30% of the revolving commitments), the agreement includes a covenant that requires the consolidated first lien net leverage ratio, which is based on the ratio of net first lien debt compared to an EBITDA calculation defined under the terms of the facilities, not to exceed 4.25 to 1.00. Although the period ended December 31, 2017 was not a compliance period, we would have been in compliance with this financial covenant if it was required to be tested at such date. Upon the existence of an event of default, the Vistra Operations Credit Facilities provide that all principal, interest and other amounts due thereunder will become immediately due and payable, either automatically or at the election of specified lenders.

*Maturities* — Long-term debt maturities at December 31, 2017 are as follows:

| | December 31, 2017 |
|---|---|
| 2018 | $ 44 |
| 2019 | 44 |
| 2020 | 44 |
| 2021 | 45 |
| 2022 | 42 |
| Thereafter | 4,189 |
| Unamortized premiums, discounts and debt issuance costs | 15 |
| Total long-term debt, including amounts due currently | $ 4,423 |

*Interest Rate Swaps* — In the Successor period from October 3, 2016 through December 31, 2016, we entered into $3.0 billion notional amount of interest rate swaps to hedge a portion of our exposure to our variable rate debt. The interest rate swaps, which became effective in January 2017, expire in July 2023 and effectively fix the interest rates between 4.50% and 4.88% on $3.0 billion of our variable rate debt. The interest rate swaps are secured by a first lien secured interest on a pari passu basis with the Vistra Operations Credit Facilities.

***Predecessor***

*DIP Roll Facilities* — In August 2016, the Predecessor entered into the DIP Roll Facilities. The facilities provided for up to $4.250 billion in senior secured, super-priority financing. The DIP Roll Facilities were senior, secured, super-priority debtor-in-possession credit agreements by and among the TCEH Debtors, the lenders that were party thereto from time to time and an administrative and collateral agent. On the Effective Date, the DIP Roll Facilities converted to the Vistra Operations Credit Facilities discussed above. Net proceeds from the DIP Roll Facilities totaled $3.465 billion and were used to repay $2.65 billion outstanding borrowings under the former DIP Facility, fund a $650 million collateral account used to backstop issuances of letters of credit and pay $107 million of issuance costs. The remaining balance was used for general corporate purposes. Additionally, $800 million of cash from collateral accounts under the former DIP Facility that was used to backstop letters of credit was released to the Predecessor to be used for general corporate purposes.

*DIP Facility* — The DIP Facility provided for up to $3.375 billion in senior secured, super-priority financing. The DIP Facility was a senior, secured, super-priority credit agreement by and among the TCEH Debtors, the lenders that were party thereto from time to time and an administrative and collateral agent. As discussed above, in August 2016, all outstanding amounts under the DIP Facility were repaid using proceeds from the DIP Roll Facilities.

## 13. COMMITMENTS AND CONTINGENCIES

### *Contractual Commitments*

At December 31, 2017 , we had contractual commitments under energy-related contracts, leases and other agreements as follows.

| | Coal purchase and transportation agreements | Pipeline transportation and storage reservation fees | Nuclear Fuel Contracts | Other Contracts |
|---|---|---|---|---|
| 2018 | $ 12 | $ 39 | $ 120 | $ 158 |
| 2019 | — | 28 | 48 | 46 |
| 2020 | — | 28 | 47 | 55 |
| 2021 | — | 29 | 55 | 36 |
| 2022 | — | 29 | 32 | 89 |
| Thereafter | — | 141 | 193 | 194 |
| Total | $ 12 | $ 294 | $ 495 | $ 578 |

Amounts in other contracts include certain long-term service and maintenance contracts related to our generation assets. The table above excludes TRA and pension and OPEB plan obligations due to the uncertainty in the timing of those payments.

Expenditures under our coal purchase and coal transportation agreements totaled $416 million , $109 million , $139 million and $218 million for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively.

At December 31, 2017 , future minimum lease payments under operating leases are as follows:

| | Operating Leases (a) |
|---|---|
| 2018 | $ 17 |
| 2019 | 15 |
| 2020 | 12 |
| 2021 | 10 |
| 2022 | 8 |
| Thereafter | 150 |
| Total future minimum lease payments | $ 212 |

(a) Includes operating leases with initial or remaining noncancellable lease terms in excess of one year.

Rent reported as operating costs, fuel costs and SG&A expenses totaled $69 million , $20 million , $39 million and $55 million for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively.

### *Guarantees*

We have entered into contracts that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. As of December 31, 2017 , there are no material outstanding claims related to our guarantee obligations, and we do not anticipate we will be required to make any material payments under these guarantees.

***Letters of Credit***

At December 31, 2017 , we had outstanding letters of credit under the Vistra Operations Credit Facilities totaling $519 million as follows:

- $390 million to support commodity risk management collateral requirements in the normal course of business, including over-the-counter and exchange-traded transactions and collateral postings with ERCOT;
- $45 million to support executory contracts and insurance agreements;
- $55 million to support our REP financial requirements with the PUCT, and
- $29 million for other credit support requirements.

***Litigation***

***Litigation Related to EPA Reviews*** — In June 2008, the EPA issued an initial request for information to Luminant under the EPA's authority under Section 114 of the Clean Air Act (CAA). The stated purpose of the request is to obtain information necessary to determine compliance with the CAA, including New Source Review standards and air permits issued by the TCEQ for the Big Brown, Monticello and Martin Lake generation facilities. In April 2013, Luminant received an additional information request from the EPA under Section 114 related to our Big Brown, Martin Lake and Monticello facilities as well as an initial information request related to our Sandow 4 generation facility.

In July 2012, the EPA sent Luminant a notice of violation alleging noncompliance with the CAA's New Source Review standards and the air permits at our Martin Lake and Big Brown generation facilities. In August 2013, the U.S. Department of Justice (DOJ), acting as the attorneys for the EPA, filed a civil enforcement lawsuit against Luminant in federal district court in Dallas, alleging violations of the CAA, including its New Source Review standards, at our Big Brown and Martin Lake generation facilities. In August 2015, the district court granted Luminant's motion to dismiss seven of the nine claims asserted by the EPA in the lawsuit. In August 2016, the EPA filed an amended complaint, eliminating one of the two remaining claims and withdrawing with prejudice a request for civil penalties in the other remaining claim. The EPA also filed a motion for entry of final judgment so that it could seek to appeal the district court's dismissal decision. In September 2016, Luminant filed a response opposing the EPA's motion for entry of final judgment. In October 2016, the district court denied the EPA's motion for entry of final judgment and agreed that the remaining claim must be fully adjudicated at the district court or withdrawn with prejudice before the EPA may appeal the dismissal decision.

In January 2017, the EPA dismissed its two remaining claims with prejudice and the district court entered final judgment in Luminant's favor. In March 2017, the EPA and the Sierra Club appealed the final judgment to the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit Court) and Luminant filed a motion in the district court to recover its attorney fees and costs. In April 2017, the district court stayed its consideration of Luminant's motion for attorney fees. In June 2017, the EPA and the Sierra Club filed their opening briefs in the Fifth Circuit Court. Luminant filed its response brief in August 2017. In September 2017, the EPA and the Sierra Club filed their reply briefs. The case has been set for oral argument at the Fifth Circuit Court in March 2018. We believe that we have complied with all requirements of the CAA and intend to vigorously defend against the remaining allegations. The lawsuit requests the maximum civil penalties available under the CAA to the government of up to $32,500 to $37,500 per day for each alleged violation, depending on the date of the alleged violation, and injunctive relief, including an order requiring the installation of best available control technology at the affected units. An adverse outcome could require substantial capital expenditures that cannot be determined at this time or retirement of the remaining plant, Martin Lake, at issue and could possibly require the payment of substantial penalties. The recent retirement of the Big Brown plant should have a favorable impact on this litigation. We cannot predict the outcome of these proceedings, including the financial effects, if any.

***Greenhouse Gas Emissions***

In August 2015, the EPA finalized rules to address greenhouse gas (GHG) emissions from new, modified and reconstructed and existing electricity generation units, referred to as the Clean Power Plan. The rule for existing facilities would establish state-specific emissions rate goals to reduce nationwide $CO_2$ emissions related to affected units by over 30% from 2012 emission levels by 2030. A number of parties, including Luminant, filed petitions for review in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) for the rule for new, modified and reconstructed plants. In addition, a number of petitions for review of the rule for existing plants were filed in the D.C. Circuit Court by various parties and groups, including challenges from twenty-seven different states opposed to the rule as well as those from, among others, certain power generating companies, various business groups and some labor unions. Luminant also filed its own petition for review. In January 2016, a coalition of states, industry (including Luminant) and other parties filed applications with the U.S. Supreme Court (Supreme Court) asking that the Supreme Court stay the rule while the D.C. Circuit Court reviews the legality of the rule for existing plants. In February 2016, the Supreme Court stayed the rule pending the conclusion of legal challenges on the rule before the D.C. Circuit Court and until the Supreme Court disposes of any subsequent petition for review. Oral argument on the merits of the legal challenges to the rule was heard in September 2016 before the entire D.C. Circuit Court.

In March 2017, President Trump issued an Executive Order entitled *Promoting Energy Independence and Economic Growth* (Order). The Order covers a number of matters, including the Clean Power Plan. Among other provisions, the Order directs the EPA to review the Clean Power Plan and, if appropriate, suspend, revise or rescind the rules on existing and new, modified and reconstructed generating units. In April 2017, in accordance with the Order, the EPA published its intent to review the Clean Power Plan. In addition, the DOJ has filed motions seeking to abate those cases until the EPA concludes its review of the rules, including any new rulemaking that results from that review. In April 2017, the D.C. Circuit Court issued orders holding the cases in abeyance for 60 days and directing the EPA to provide status reports at 30-day intervals. The D.C. Circuit Court further ordered that all parties file supplemental briefs in May 2017 on whether the cases should be remanded to the EPA rather than held in abeyance. The D.C. Circuit Court entered additional 60-day abeyances in August 2017 and November 2017. The latest 60-day abeyance expired in January 2018, and the D.C. Circuit Court has yet to take further action on the EPA's request to continue the abeyance. In October 2017, the EPA issued a proposed rule that would repeal the Clean Power Plan. The proposed repeal focuses on what the EPA believes to be the unlawful nature of the Clean Power Plan and asks for public comment on the EPA's interpretations of its authority under the Clean Air Act. We currently plan to submit comments in response to the proposed repeal by April 2018. In December 2017, the EPA published an advance notice of proposed rulemaking (ANPR) soliciting information from the public as the EPA considers proposing a future rule. We currently plan on submitting comments by the February 2018 deadline. While we cannot predict the outcome of these rulemakings and related legal proceedings, or estimate a range of reasonably probable costs, if the rules are ultimately implemented or upheld as they were issued, they could have a material impact on our results of operations, liquidity or financial condition.

***Cross-State Air Pollution Rule (CSAPR)***

In July 2011, the EPA issued the CSAPR, compliance with which would have required significant additional reductions of sulfur dioxide ($SO_2$) and nitrogen oxide ($NO_X$) emissions from our fossil fueled generation units. In February 2012, the EPA released a final rule (Final Revisions) and a proposed rule revising certain aspects of the CSAPR, including increases in the emissions budgets for Texas and our generation assets as compared to the July 2011 version of the rule. In June 2012, the EPA finalized the proposed rule (Second Revised Rule).

The CSAPR became effective January 1, 2015. In July 2015, following a remand of the case from the Supreme Court to consider further legal challenges, the D.C. Circuit Court ruled in favor of Luminant and other petitioners, holding that the CSAPR emissions budgets over-controlled Texas and other states. The D.C. Circuit Court remanded those states' budgets to the EPA for prompt reconsideration. While Luminant planned to participate in the EPA's reconsideration process to develop increased budgets for the 1997 ozone standard that do not over-control Texas, the EPA instead responded to the remand by proposing a new rulemaking that created new $NO_X$ ozone season budgets for the 2008 ozone standard without addressing the over-controlling budgets for the 1997 standard. Comments on the EPA's proposal were submitted by Luminant in February 2016. In August 2016, the EPA disapproved certain aspects of Texas's infrastructure State Implementation Plan (SIP) for the 2008 ozone National Ambient Air Quality Standard and imposed a Federal Implementation Plan (FIP) in its place in October 2016. Texas filed a petition in the Fifth Circuit Court challenging the SIP disapproval and Luminant intervened in support of Texas's challenge. The parties moved to stay the case and the court responded by dismissing the petition with the right to reinstate as provided in the Fifth Circuit Court's rules. The State of Texas and Luminant have also both filed challenges in the D.C. Circuit Court challenging the EPA's FIP and those cases are currently pending before that court. With respect to Texas's $SO_2$ emission budgets, in June 2016, the EPA issued a memorandum describing the EPA's proposed approach for responding to the D.C. Circuit Court's remand for reconsideration of the CSAPR $SO_2$ emission budgets for Texas and three other states that had been remanded to the EPA by the D.C. Circuit Court. In the memorandum, the EPA stated that those four states could either voluntarily participate in the CSAPR by submitting a SIP revision adopting the $SO_2$ budgets that had been previously held invalid by the D.C. Circuit Court and the current annual $NO_X$ budgets or, if the state chooses not to participate in the CSAPR, the EPA could withdraw the CSAPR FIP by the fall of 2016 for those states and address any interstate transport and regional haze obligations on a state-by-state basis. Texas has not indicated that it intends to adopt the over-controlling budgets and, in November 2016, the EPA proposed to withdraw the CSAPR FIP addressing $SO_2$ and NOx for Texas. In September 2017, the EPA finalized its proposal to remove Texas from the annual CSAPR programs. The Sierra Club and the National Parks Conservation Association filed a petition for review in the D.C. Circuit Court challenging that final rule. Luminant has intervened on behalf of the EPA. As a result of the EPA's action, Texas electric generating units are no longer subject to the CSAPR annual $SO_2$ and $NO_X$ limits, but remain subject to the CSAPR's ozone season $NO_X$ requirements. While we cannot predict the outcome of future proceedings related to the CSAPR, including the EPA's recent actions concerning the CSAPR annual emissions budgets for affected states participating in the CSAPR program, based upon our current operating plans, including the recent retirements of our Monticello, Big Brown and Sandow 4 plants (see Note 4 ), we do not believe that the CSAPR itself will cause any material operational, financial or compliance issues to our business or require us to incur any material compliance costs.

***Regional Haze — Reasonable Progress and Long-Term Strategies***

The Regional Haze Program of the CAA establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I federal areas, like national parks, which impairment results from man-made pollution." There are two components to the Regional Haze Program. First, states must establish goals for reasonable progress for Class I federal areas within the state and establish long-term strategies to reach those goals and to assist Class I federal areas in neighboring states to achieve reasonable progress set by those states towards a goal of natural visibility by 2064. In February 2009, the TCEQ submitted a SIP concerning regional haze (Regional Haze SIP) to the EPA. In December 2011, the EPA proposed a limited disapproval of the Regional Haze SIP due to its reliance on the Clean Air Interstate Rule (CAIR) instead of the EPA's replacement CSAPR program that the EPA finalized in July 2011. The EPA finalized the limited disapproval of Texas's Regional Haze SIP in June 2012. In August 2012, Luminant filed a petition for review in the Fifth Circuit Court challenging the EPA's limited disapproval of the Regional Haze SIP on the grounds that the CAIR continued in effect pending the D.C. Circuit Court's decision in the CSAPR litigation. In August 2012, Luminant filed a motion to intervene in a case filed by industry groups and other states and private parties in the D.C. Circuit Court challenging the EPA's limited disapproval and issuance of a FIP regarding the regional haze best available retrofit technology (BART) program. The Fifth Circuit Court case has since been transferred to the D.C. Circuit Court and consolidated with other pending BART program regional haze appeals. Briefing in the D.C. Circuit Court was completed in March 2017, and oral argument was held in November 2017.

In May 2014, the EPA issued requests for information under Section 114 of the CAA to Luminant and other generators in Texas related to the reasonable progress program. After releasing a proposed rule in November 2014 and receiving comments from a number of parties, including Luminant and the State of Texas in April 2015, the EPA issued a final rule in January 2016 approving in part and disapproving in part Texas' SIP for Regional Haze and issuing a FIP for Regional Haze. In the rule, the EPA asserts that the Texas SIP does not show reasonable progress in improving visibility for two areas in Texas and that its long-term strategy fails to make emission reductions needed to achieve reasonable progress in improving visibility in the Wichita Mountains of Oklahoma. The EPA's emission limits in the FIP assume additional control equipment for specific lignite/coal-fueled generation units across Texas, including new flue gas desulfurization systems (scrubbers) at seven electricity generating units and upgrades to existing scrubbers at seven generation units. Specifically, for Luminant, the EPA's FIP is based on new scrubbers at Big Brown Units 1 and 2 and Monticello Units 1 and 2 and scrubber upgrades at Martin Lake Units 1, 2 and 3, Monticello Unit 3 and Sandow Unit 4. Under the terms of the rule, subject to the legal proceedings described in the following paragraph, the scrubber upgrades would be required by February 2019, and the new scrubbers would be required by February 2021.

In March 2016, Luminant and a number of other parties, including the State of Texas, filed petitions for review in the Fifth Circuit Court challenging the FIP's Texas requirements. Luminant and other parties also filed motions to stay the FIP while the court reviews the legality of the EPA's action. In July 2016, the Fifth Circuit Court denied the EPA's motion to dismiss Luminant's challenge to the FIP and denied the EPA's motion to transfer the challenges Luminant, the other industry petitioners and the State of Texas filed to the D.C. Circuit Court. In addition, the Fifth Circuit Court granted the motions to stay filed by Luminant, the other industry petitioners and the State of Texas pending final review of the petitions for review. The case was abated until the end of November 2016 in order to allow the parties to pursue settlement discussions. Settlement discussions were unsuccessful, and in December 2016 the EPA filed a motion seeking a voluntary remand of the rule back to the EPA for further consideration of Luminant's pending request for administrative reconsideration. Luminant and some of the other petitioners filed a response opposing the EPA's motion to remand and filed a cross motion for vacatur of the rule in December 2016. In March 2017, the Fifth Circuit Court remanded the rule back to the EPA for reconsideration in light of the Court's prior determination that we and the other petitioners demonstrated a substantial likelihood that the EPA exceeded its statutory authority and acted arbitrarily and capriciously, but the Court denied all of the other pending motions. The stay of the rule (and the emission control requirements) remains in effect. In addition, the Fifth Circuit Court denied the EPA's motion to lift the stay as to parts of the rule implicated in the EPA's subsequent BART proposal and the Court is retaining jurisdiction of the case and requiring the EPA to file status reports on its reconsideration every 60 days. The recent retirements of our Monticello, Big Brown and Sandow 4 plants should have a favorable impact on this rulemaking and litigation. While we cannot predict the outcome of the rulemaking and legal proceedings, or estimate a range of reasonably possible costs, the result may have a material impact on our results of operations, liquidity or financial condition.

### *Regional Haze — Best Available Retrofit Technology*

The second part of the Regional Haze Program subjects certain electricity generation units built between 1962 and 1977, to BART standards designed to improve visibility if such units cause or contribute to impairment of visibility in a federal class I area. BART reductions of $SO_2$ and $NO_X$ are required either on a unit-by-unit basis or are deemed satisfied by state participation in an EPA-approved regional trading program such as the CSAPR or other approved alternative program. In response to a lawsuit by environmental groups, the U.S. District Court for the District of Columbia (D.C. District Court) issued a consent decree in March 2012 that required the EPA to propose a decision on the Regional Haze SIP by May 2012 and finalize that decision by November 2012. The consent decree requires a FIP for any provisions that the EPA disapproves. The D.C. District Court has amended the consent decree several times to extend the dates for the EPA to propose and finalize a decision on the Regional Haze SIP. The consent decree was modified in December 2015 to extend the deadline for the EPA to finalize action on the determination and adoption of requirements for BART for electricity generation. Under the amended consent decree, the EPA had until December 2016 to propose, and had until September 2017 to finalize, either approval of the state plan or a FIP for BART for Texas electricity generation sources if the EPA determines that BART requirements have not been met. The EPA issued a proposed BART FIP for Texas in January 2017. The EPA's proposed emission limits assume additional control equipment for specific lignite/coal-fueled generation units across Texas, including new flue gas desulfurization systems (scrubbers) at 12 electric generation units and upgrades to existing scrubbers at four electric generation units. Specifically, for Luminant, the EPA's proposed emission limitations were based on new scrubbers at Big Brown Units 1 and 2 and Monticello Units 1 and 2 and scrubber upgrades at Martin Lake Units 1, 2 and 3 and Monticello Unit 3. Luminant evaluated the requirements and potential financial and operational impacts of the proposed rule, but new scrubbers at the Big Brown and Monticello units necessary to achieve the emission limits required by the FIP (if those limits are possible to attain), along with the existence of low wholesale power prices in ERCOT, would challenge the long-term economic viability of those units. Under the terms of the proposed rule, the scrubber upgrades would have been required within three years of the effective date of the final rule and the new scrubbers will be required within five years of the effective date of the final rule. We submitted comments on the proposed FIP in May 2017.

The EPA signed the final BART FIP for Texas in September 2017. The rule is a partial approval of Texas's 2009 SIP and a partial FIP. In response to comments on the proposed rule submitted to the EPA, for $SO_2$, the rule creates an intrastate Texas emission allowance trading program as a "BART alternative" that operates in a similar fashion to a CSAPR trading program. The program includes 39 generating units, including our Martin Lake, Big Brown, Monticello, Sandow 4, Stryker 2 and Graham 2 plants. Of the 39 units, 30 are BART-eligible, three are co-located with a BART-eligible unit and six units are included in the program based on a visibility impacts analysis by the EPA. The 39 units represent 89% of $SO_2$ emissions from Texas electric generating units in 2016 and 85% of all CSAPR $SO_2$ allowance allocations for Texas existing electric generating units. The compliance obligations in the program will start on January 1, 2019. The identified units will receive an annual allowance allocation that is equal to their most recent annual CSAPR $SO_2$ allocation. Luminant's units covered by the program are allocated 91,222 allowances annually. Under the rule, a unit that is listed that does not operate for two consecutive years starting after 2018 would no longer receive allowances after the fifth year of non-operation. We believe the recent retirements of our Monticello, Big Brown and Sandow 4 plants will enhance our ability to comply with this BART rule for $SO_2$. For $NO_X$, the rule adopts the CSAPR's ozone program as BART and for particulate matter, the rule approves Texas's SIP that determines that no electric generating units are subject to BART for particulate matter. The National Parks Conservation Association, the Sierra Club and the Environmental Defense Fund filed a petition challenging the rule in the Fifth Circuit Court as well as a petition for reconsideration filed with the EPA. Additionally, the National Parks Conservation Association, the Sierra Club, the Environmental Defense Fund and other environmental groups filed a motion in the D.C. Circuit Court in October 2017 to enforce the terms of the consent decree that was originally entered in 2012. The EPA filed a cross-motion to terminate the consent decree in October 2017. These motions remain pending before the D.C. Circuit Court. Luminant has intervened on behalf of the EPA in that action. While we cannot predict the outcome of the rulemaking and potential legal proceedings, we believe the rule, if ultimately implemented or upheld as issued, will not have a material impact on our results of operation, liquidity or financial condition.

### *Intersection of the CSAPR and Regional Haze Programs*

Historically the EPA has considered compliance with a regional trading program, such as the CSAPR, as satisfying a state's obligations under the BART portion of the Regional Haze Program. However, in the reasonable progress FIP, the EPA diverged from this approach and did not treat Texas' compliance with the CSAPR as satisfying its obligations under the BART portion of the Regional Haze Program. The EPA concluded that it would not be appropriate to finalize that determination given the remand of the CSAPR budgets. As described above, the EPA has now removed Texas from the annual CSAPR trading programs for $SO_2$ and $NO_X$ and has issued a final BART FIP for Texas.

***Affirmative Defenses During Malfunctions***

In February 2013, in response to a petition for rulemaking filed by the Sierra Club, the EPA proposed a rule requiring certain states to replace SIP exemptions for excess emissions during malfunctions with an affirmative defense. Texas was not included in that original proposal since it already had an EPA-approved affirmative defense provision in its SIP that was found to be lawful by the Fifth Circuit Court in 2013. In 2014, as a result of a D.C. Circuit Court decision striking down an affirmative defense in another EPA rule, the EPA revised its 2013 proposal to extend the EPA's proposed findings of inadequacy to states that have affirmative defense provisions, including Texas. The EPA's revised proposal would require Texas to remove or replace its EPA-approved affirmative defense provisions for excess emissions during startup, shutdown and maintenance events. In May 2015, the EPA finalized the proposal. In June 2015, Luminant filed a petition for review in the Fifth Circuit Court challenging certain aspects of the EPA's final rule as they apply to the Texas SIP. The State of Texas and other parties have also filed similar petitions in the Fifth Circuit Court. In August 2015, the Fifth Circuit Court transferred the petitions that Luminant and other parties filed to the D.C. Circuit Court, and in October 2015 the petitions were consolidated with the pending petitions challenging the EPA's action in the D.C. Circuit Court. Briefing in the D.C. Circuit Court on the challenges was completed in October 2016 and oral argument was originally set for May 2017. However, in April 2017, the court granted the EPA's motion to continue oral argument and ordered that the case be held in abeyance with the EPA to provide status reports to the court on the EPA's review of the action at 90-day intervals. We cannot predict the timing or outcome of this proceeding, or estimate a range of reasonably possible costs, but implementation of the rule as finalized may have a material impact on our results of operations, liquidity or financial condition.

***$SO_2$ Designations for Texas***

In February 2016, the EPA notified Texas of the EPA's preliminary intention to designate nonattainment areas for counties surrounding our Big Brown, Monticello and Martin Lake generation plants based on modeling data submitted to the EPA by the Sierra Club. Such designation would potentially require the implementation of various controls or other requirements to demonstrate attainment. Luminant submitted comments challenging the use of modeling data rather than data from actual air quality monitoring equipment. In November 2016, the EPA finalized its proposed designations for Texas including finalizing the nonattainment designations for the areas referenced above. In doing so, the EPA ignored contradictory modeling that we submitted with our comments. The final designation mandates would be for Texas to begin the multi-year process to evaluate what potential emission controls or operational changes, if any, may be necessary to demonstrate attainment. In February 2017, the State of Texas and Luminant filed challenges to the nonattainment designations in the Fifth Circuit Court and protective petitions in the D.C. Circuit Court. In March 2017, the EPA filed a motion to transfer or dismiss our Fifth Circuit Court petition, and the State of Texas and Luminant filed an opposition to that motion. Briefing on that motion in the Fifth Circuit Court was completed in May 2017, and the Fifth Circuit Court held oral argument on that motion in July 2017. In August 2017, the Fifth Circuit Court denied the EPA's motion to transfer our challenge to the D.C. Circuit Court. In October 2017, the Fifth Circuit Court granted the EPA's motion to hold the case in abeyance in light of the EPA's representation that it intended to revisit the rule. In December 2017, the TCEQ submitted a petition for reconsideration to the EPA. In addition, with respect to Monticello and Big Brown, the retirement of those plants should favorably impact our legal challenge to the nonattainment designations in that the nonattainment designation for Freestone County and Titus County are based solely on the Sierra Club modeling of alleged $SO_2$ emissions from Monticello and Big Brown. We dispute the Sierra Club's modeling. Regardless, considering these retirements, the nonattainment designation for those counties are no longer supported. While we cannot predict the outcome of this matter, or estimate a range of reasonably possible costs, the result may have a material impact on our results of operations, liquidity or financial condition.

***Litigation Related to the Merger***

In January 2018, a purported Dynegy stockholder filed a putative class action lawsuit in the U.S. District Court for the Southern Division of Texas, Houston Division, alleging that Dynegy, each member of the Dynegy board of directors and Vistra Energy violated federal securities laws by filing a Form S-4 Registration Statement in connection with the Merger that omits purportedly material information. The lawsuit seeks to enjoin the Merger and to have Dynegy and Vistra Energy issue an amended Form S-4 or, alternatively, damages if the Merger closes without an amended Form S-4 having been filed. Two other related lawsuits were also filed but neither of those named Vistra Energy. In February 2018, Vistra Energy and Dynegy filed supplemental disclosures to the Registration Statement and the plaintiffs agreed to forego any further effort to enjoin the Merger, dismiss the individual claims with prejudice, and dismiss without prejudice claims of the putative class following the stockholder vote scheduled for March 2, 2018.

***Other Matters***

We are involved in various legal and administrative proceedings in the normal course of business, the ultimate resolutions of which, in the opinion of management, are not anticipated to have a material effect on our results of operations, liquidity or financial condition.

***Labor Contracts***

We employ certain personnel who are represented by labor unions, the terms of whose employment are governed by collective bargaining agreements. The initial term of all collective bargaining agreements covering bargaining unit personnel engaged in lignite mining operations, lignite-, coal- and nuclear-fueled generation operations and some of our natural gas-fueled generation operations expired in March 2017, but remain effective pursuant to evergreen provisions unless and until terminated by either party. Vistra Energy is currently negotiating a new collective bargaining agreement with one of our local unions, while new agreements with our two other local unions have been ratified, but not yet executed. While we cannot predict the outcome of labor contract negotiations, we do not expect any changes in collective bargaining agreements to have a material adverse effect on our results of operations, liquidity or financial condition.

***Nuclear Insurance***

Nuclear insurance includes nuclear liability coverage, property damage, decontamination and accidental premature decommissioning coverage and accidental outage and/or extra expense coverage. We maintain nuclear insurance that meets or exceeds requirements promulgated by Section 170 (Price-Anderson) of the Atomic Energy Act (the Act) and Title 10 of the Code of Federal Regulations. We intend to maintain insurance against nuclear risks as long as such insurance is available. We are self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered per policy exclusions, terms and limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Any such self-insured losses could have a material adverse effect on our results of operations, liquidity or financial condition.

With regard to liability coverage, the Act provides for financial protection for the public in the event of a significant nuclear generation plant incident. The Act sets the statutory limit of public liability for a single nuclear incident at $13.4 billion and requires nuclear generation plant operators to provide financial protection for this amount. However, the United States Congress could impose revenue-raising measures on the nuclear industry to pay claims that exceed the $13.4 billion limit for a single incident. As required, we insure against a possible nuclear incident at our Comanche Peak facility resulting in public nuclear-related bodily injury and property damage through a combination of private insurance and an industry-wide retrospective payment plan known as Secondary Financial Protection (SFP).

Under the SFP, in the event of any single nuclear liability loss in excess of $450 million at any nuclear generation facility in the United States, each operating licensed reactor in the United States is subject to an annual assessment of up to $127.3 million . This approximately $127.3 million maximum assessment is subject to increases for inflation every five years, with the next expected adjustment scheduled to occur in September 2018. Assessments are currently limited to $19 million per operating licensed reactor per year per incident. As of December 31, 2017 , our maximum potential assessment under the industry retrospective plan would be approximately $254.6 million per incident but no more than $37.9 million in any one year for each incident. The potential assessment is triggered by a nuclear liability loss in excess of $450 million per accident at any nuclear facility.

The United States Nuclear Regulatory Commission (NRC) requires that nuclear generation plant license holders maintain at least $1.06 billion of nuclear decontamination and property damage insurance, and requires that the proceeds thereof be used to place a plant in a safe and stable condition, to decontaminate a plant pursuant to a plan submitted to, and approved by, the NRC prior to using the proceeds for plant repair or restoration, or to provide for premature decommissioning. We maintain nuclear decontamination and property damage insurance for our Comanche Peak facility in the amount of $2.25 billion and non-nuclear related property damage in the amount of $1.5 billion (subject to a $5 million deductible per accident except for natural hazards which are subject to a $9.5 million deductible per accident), above which we are self-insured.

We also maintain Accidental Outage insurance to cover the additional costs of obtaining replacement electricity from another source if one or both of the units at our Comanche Peak facility are out of service for more than twelve weeks as a result of covered direct physical damage. Such coverage provides for weekly payments per unit up to $4.5 million for the first 52 weeks and up to $3.6 million for the remaining 71 weeks. The total maximum coverage is $328 million for non-nuclear property damage and $490 million for nuclear property damage. The coverage amounts applicable to each unit will be reduced to 80% if both units are out of service at the same time as a result of the same accident.

## 14. EQUITY

***Successor Shareholders' Equity***

*Equity Issuances and Repurchases* — Changes in the number of shares of common stock outstanding for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 are reflected in the table below.

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Shares outstanding at beginning of period | 427,580,232 | — |
| Shares issued (a) | 818,570 | 427,580,232 |
| Shares repurchased | — | — |
| Shares outstanding at end of period | 428,398,802 | 427,580,232 |

(a) Includes share awards granted to directors and other nonemployees.

*Dividends* — Vistra Energy did not declare or pay any dividends during the year ended December 31, 2017 . In December 2016, the board of directors of Vistra Energy approved the payment of a special cash dividend (Special Dividend) in the aggregate amount of approximately $1 billion ( $2.32 per share of common stock) to holders of record of our common stock on December 19, 2016. The dividend was funded using borrowings under the Vistra Operations Credit Facilities.

*Dividend Restrictions* — The agreement governing the Vistra Operations Credit Facilities (the Credit Facilities Agreement) generally restricts the ability of Vistra Operations Company LLC (Vistra Operations) to make distributions to any direct or indirect parent unless such distributions are expressly permitted thereunder. As of December 31, 2017 , Vistra Operations can distribute approximately $1.0 billion to Vistra Energy Corp. (Parent) under the Credit Facilities Agreement without the consent of any party. The amount that can be distributed by Vistra Operations to Parent was partially reduced by distributions made by Vistra Operations to Parent during the year ended December 31, 2017 of approximately $1.1 billion . Additionally, Vistra Operations may make distributions to Parent in amounts sufficient for Parent to make any payments required under the TRA or the Tax Matters Agreement or, to the extent arising out of Parent's ownership or operation of Vistra Operations, to pay any taxes or general operating or corporate overhead expenses. As of December 31, 2017 , the maximum amount of restricted net assets of Vistra Operations that may not be distributed to Parent totaled $3.9 billion .

Under applicable Delaware General Corporate Law, we are prohibited from paying any distribution to the extent that such distribution exceeds the value of our "surplus," which is defined as the excess of our net assets above our capital (the aggregate par value of all outstanding shares of our stock).

*Accumulated Other Comprehensive Income* — During the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, we recorded changes in the funded status of our pension and other postretirement employee benefit liability totaling $(23) million and $6 million , respectively. During the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, no amounts were reclassified from accumulated other comprehensive income.

***Predecessor Membership Interests***

TCEH paid no dividends in the period from January 1, 2016 through October 2, 2016 nor the year ended December 31, 2015.

## 15. FAIR VALUE MEASUREMENTS

We utilize several different valuation techniques to measure the fair value of assets and liabilities, relying primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities for those items that are measured on a recurring basis. We use a mid-market valuation convention (the mid-point price between bid and ask prices) as a practical expedient to measure fair value for the majority of our assets and liabilities and use valuation techniques to maximize the use of observable inputs and minimize the use of unobservable inputs. Our valuation policies and procedures were developed, maintained and validated by a centralized risk management group that reports to the Vistra Energy Chief Financial Officer.

Fair value measurements of derivative assets and liabilities incorporate an adjustment for credit-related nonperformance risk. These nonperformance risk adjustments take into consideration master netting arrangements, credit enhancements and the credit risks associated with our credit standing and the credit standing of our counterparties (see Note 16 for additional information regarding credit risk associated with our derivatives). We utilize credit ratings and default rate factors in calculating these fair value measurement adjustments.

We categorize our assets and liabilities recorded at fair value based upon the following fair value hierarchy:

- Level 1 valuations use quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. Our Level 1 assets and liabilities include CME or ICE (electronic commodity derivative exchanges) futures and options transacted through clearing brokers for which prices are actively quoted. We report the fair value of CME and ICE transactions without taking into consideration margin deposits, with the exception of certain margin amounts related to changes in fair value on certain CME transactions that, beginning in January 2017, are legally characterized as settlement of derivative contracts rather than collateral.

- Level 2 valuations utilize over-the-counter broker quotes, quoted prices for similar assets or liabilities that are corroborated by correlations or other mathematical means, and other valuation inputs such as interest rates and yield curves observable at commonly quoted intervals. We attempt to obtain multiple quotes from brokers that are active in the markets in which we participate and require at least one quote from two brokers to determine a pricing input as observable. The number of broker quotes received for certain pricing inputs varies depending on the depth of the trading market, each individual broker's publication policy, recent trading volume trends and various other factors.

- Level 3 valuations use unobservable inputs for the asset or liability. Unobservable inputs are used to the extent observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. We use the most meaningful information available from the market combined with internally developed valuation methodologies to develop our best estimate of fair value. Significant unobservable inputs used to develop the valuation models include volatility curves, correlation curves, illiquid pricing delivery periods and locations and credit-related nonperformance risk assumptions. These inputs and valuation models are developed and maintained by employees trained and experienced in market operations and fair value measurements and validated by the Company's risk management group.

With respect to amounts presented in the following fair value hierarchy tables, the fair value measurement of an asset or liability ( *e.g.* , a contract) is required to fall in its entirety in one level, based on the lowest level input that is significant to the fair value measurement.

Assets and liabilities measured at fair value on a recurring basis consisted of the following at the respective balance sheet dates shown below:

| December 31, 2017 | Level 1 | Level 2 | Level 3 (a) | Reclassification (b) | Total |
|---|---|---|---|---|---|
| Assets: | | | | | |
| Commodity contracts | $ 47 | $ 98 | $ 75 | $ 2 | $ 222 |
| Interest rate swaps | — | 18 | — | 8 | 26 |
| Nuclear decommissioning trust – equity securities (c) | 468 | — | — | — | 468 |
| Nuclear decommissioning trust – debt securities (c) | — | 430 | — | — | 430 |
| Sub-total | $ 515 | $ 546 | $ 75 | $ 10 | 1,146 |
| Assets measured at net asset value (d): | | | | | |
| Nuclear decommissioning trust – equity securities (c) | | | | | 290 |
| Total assets | | | | | $ 1,436 |
| Liabilities: | | | | | |
| Commodity contracts | $ 45 | $ 143 | $ 128 | $ 2 | $ 318 |
| Interest rate swaps | — | — | — | 8 | 8 |
| Total liabilities | $ 45 | $ 143 | $ 128 | $ 10 | $ 326 |

| December 31, 2016 | Level 1 | Level 2 | Level 3 (a) | Reclassification (b) | Total |
|---|---|---|---|---|---|
| Assets: | | | | | |
| Commodity contracts | $ 167 | $ 131 | $ 98 | $ — | $ 396 |
| Interest rate swaps | — | 5 | — | 13 | 18 |
| Nuclear decommissioning trust – equity securities (c) | 425 | — | — | — | 425 |
| Nuclear decommissioning trust – debt securities (c) | — | 340 | — | — | 340 |
| Sub-total | $ 592 | $ 476 | $ 98 | $ 13 | 1,179 |
| Assets measured at net asset value (d): | | | | | |
| Nuclear decommissioning trust – equity securities (c) | | | | | 247 |
| Total assets | | | | | $ 1,426 |
| Liabilities: | | | | | |
| Commodity contracts | $ 302 | $ 15 | $ 15 | $ — | $ 332 |
| Interest rate swaps | — | 16 | — | 13 | 29 |
| Total liabilities | $ 302 | $ 31 | $ 15 | $ 13 | $ 361 |

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(a) See table below for description of Level 3 assets and liabilities.
(b) Fair values are determined on a contract basis, but certain contracts result in a current asset and a noncurrent liability, or vice versa, as presented in our consolidated balance sheets.
(c) The nuclear decommissioning trust investment is included in the other investments line in our consolidated balance sheets. See Note 21 .
(d) The fair value amounts presented in this line are intended to permit reconciliation of the fair value hierarchy to the amounts presented in our consolidated balance sheets. Certain investments measured at fair value using the net asset value per share (or its equivalent) have not been classified in the fair value hierarchy.

Commodity contracts consist primarily of natural gas, electricity, coal, fuel oil and uranium agreements and include financial instruments entered into for economic hedging purposes as well as physical contracts that have not been designated as normal purchases or sales. Interest rate swaps are used to reduce exposure to interest rate changes by converting floating-rate interest to fixed rates. See Note 16 for further discussion regarding derivative instruments.

Nuclear decommissioning trust assets represent securities held for the purpose of funding the future retirement and decommissioning of our nuclear generation facility. These investments include equity, debt and other fixed-income securities consistent with investment rules established by the NRC and the PUCT.

The following tables present the fair value of the Level 3 assets and liabilities by major contract type and the significant unobservable inputs used in the valuations at December 31, 2017 and 2016 :

**December 31, 2017**

| Contract Type (a) | Fair Value Assets | Fair Value Liabilities | Fair Value Total | Valuation Technique | Significant Unobservable Input | Range (b) |
|---|---|---|---|---|---|---|
| Electricity purchases and sales | $ 12 | $ (33) | $ (21) | Valuation Model | Hourly price curve shape (c) | $0 to $40/ MWh |
| | | | | | Illiquid delivery periods for ERCOT hub power prices and heat rates (d) | $20 to $70/ MWh |
| Electricity options | — | (91) | (91) | Option Pricing Model | Gas to power correlation (e) | 30% to 100% |
| | | | | | Power volatility (e) | 5% to 180% |
| Electricity congestion revenue rights | 45 | (4) | 41 | Market Approach (f) | Illiquid price differences between settlement points (g) | $0 to $15/ MWh |
| Other (h) | 18 | — | 18 | | | |
| Total | $ 75 | $ (128) | $ (53) | | | |

**December 31, 2016**

| Contract Type (a) | Fair Value Assets | Fair Value Liabilities | Fair Value Total | Valuation Technique | Significant Unobservable Input | Range (b) |
|---|---|---|---|---|---|---|
| Electricity purchases and sales | $ 32 | $ — | $ 32 | Valuation Model | Hourly price curve shape (c) | $0 to $35/ MWh |
| | | | | | Illiquid delivery periods for ERCOT hub power prices and heat rates (d) | $30 to $70/ MWh |
| Electricity congestion revenue rights | 42 | (6) | 36 | Market Approach (f) | Illiquid price differences between settlement points (g) | $0 to $10/ MWh |
| Other (h) | 24 | (9) | 15 | | | |
| Total | $ 98 | $ (15) | $ 83 | | | |

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(a) Electricity purchase and sales contracts include power and heat rate positions in ERCOT regions. Electricity congestion revenue rights contracts consist of forward purchase contracts (swaps and options) used to hedge electricity price differences between settlement points within ERCOT. Electricity options consist of physical electricity options and spread options.
(b) The range of the inputs may be influenced by factors such as time of day, delivery period, season and location.
(c) Based on the historical range of forward average hourly ERCOT North Hub prices.
(d) Based on historical forward ERCOT power price and heat rate variability.
(e) Based on historical forward correlation and volatility within ERCOT.
(f) While we use the market approach, there is insufficient market data to consider the valuation liquid.
(g) Based on the historical price differences between settlement points within ERCOT hubs and load zones.
(h) Other includes contracts for natural gas, weather options and coal options. December 31, 2016 also includes an immaterial amount of electricity options.

There were no transfers between Level 1 and Level 2 of the fair value hierarchy for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 . See the table below for discussion of transfers between Level 2 and Level 3 for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 .

The following table presents the changes in fair value of the Level 3 assets and liabilities for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 .

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Net asset balance at beginning of period (a) | $ 83 | $ 81 | $ 37 | $ 35 |
| Total unrealized valuation gains (losses) | (136) | 31 | 122 | 27 |
| Purchases, issuances and settlements (b): | | | | |
| Purchases | 69 | 15 | 37 | 49 |
| Issuances | (22) | (7) | (20) | (13) |
| Settlements | (106) | (30) | (51) | (48) |
| Transfers into Level 3 (c) | 4 | 3 | 1 | 1 |
| Transfers out of Level 3 (c) | 71 | (10) | 1 | (14) |
| Earn-out provision (d) | (16) | — | — | — |
| Net liabilities assumed in the Lamar and Forney Acquisition (Note 3) (e) | — | — | (30) | — |
| Net change (f) | (136) | 2 | 60 | 2 |
| Net asset (liability) balance at end of period | $ (53) | $ 83 | $ 97 | $ 37 |
| Unrealized valuation gains (losses) relating to instruments held at end of period | $ (98) | $ 28 | $ 98 | $ 18 |

(a) The beginning balance for the Successor period from October 3, 2016 through December 31, 2016 reflects a $16 million adjustment to the fair value of certain Level 3 assets driven by power prices utilized by the Successor for unobservable delivery periods.

(b) Settlements reflect reversals of unrealized mark-to-market valuations previously recognized in net income. Purchases and issuances reflect option premiums paid or received.

(c) Includes transfers due to changes in the observability of significant inputs. All Level 3 transfers during the periods presented are in and out of Level 2. For the year ended December 31, 2017, transfers out of Level 3 primarily consists of electricity derivatives where forward pricing inputs have become observable.

(d) Represents initial fair value of the earn-out provision incurred as part of the Odessa Acquisition. See Note 3 .

(e) Includes fair value of Level 3 assets and liabilities as of the purchase date and any related rolloff between the purchase date and the period ended October 2, 2016.

(f) Activity excludes change in fair value in the month positions settle. For the Successor period, substantially all changes in values of commodity contracts (excluding the initial fair value of the earn-out provision related to the Odessa Acquisition in 2017) are reported as operating revenues in our statements of consolidated income (loss). For the Predecessor period, substantially all changes in values of commodity contracts (excluding net liabilities assumed in the Lamar and Forney Acquisition in 2016) are reported as net gain from commodity hedging and trading activities in the statements of consolidated income (loss).

## 16. COMMODITY AND OTHER DERIVATIVE CONTRACTUAL ASSETS AND LIABILITIES

### *Strategic Use of Derivatives*

We transact in derivative instruments, such as options, swaps, futures and forward contracts, to manage commodity price and interest rate risk. See Note 15 for a discussion of the fair value of derivatives.

***Commodity Hedging and Trading Activity*** — We utilize natural gas and electricity derivatives to reduce exposure to changes in electricity prices primarily to hedge future revenues from electricity sales from our generation assets. We also utilize short-term electricity, natural gas, coal, fuel oil and uranium derivative instruments for fuel hedging and other purposes. Counterparties to these transactions include energy companies, financial institutions, electric utilities, independent power producers, oil and gas producers, local distribution companies and energy marketing companies. Unrealized gains and losses arising from changes in the fair value of derivative instruments as well as realized gains and losses upon settlement of the instruments are reported in our statements of consolidated income (loss) in operating revenues and fuel, purchased power costs and delivery fees in the Successor period and net gain from commodity hedging and trading activities in the Predecessor period.

***Interest Rate Swaps*** — Interest rate swap agreements are used to reduce exposure to interest rate changes by converting floating-rate interest rates to fixed rates, thereby hedging future interest costs and related cash flows. Unrealized gains and losses arising from changes in the fair value of the swaps as well as realized gains and losses upon settlement of the swaps are reported in our statements of consolidated income (loss) in interest expense and related charges.

### *Financial Statement Effects of Derivatives*

Substantially all derivative contractual assets and liabilities are accounted for under mark-to-market accounting consistent with accounting standards related to derivative instruments and hedging activities. The following tables provide detail of derivative contractual assets and liabilities as reported in our consolidated balance sheets at December 31, 2017 and 2016 . Derivative asset and liability totals represent the net value of the contract, while the balance sheet totals represent the gross value of the contract.

| | December 31, 2017 | | | | |
|---|---|---|---|---|---|
| | Derivative Assets | | Derivative Liabilities | | |
| | Commodity Contracts | Interest Rate Swaps | Commodity Contracts | Interest Rate Swaps | Total |
| Current assets | $ 190 | $ — | $ — | $ — | $ 190 |
| Noncurrent assets | 30 | 22 | 2 | 4 | 58 |
| Current liabilities | — | (4) | (216) | (4) | (224) |
| Noncurrent liabilities | — | — | (102) | — | (102) |
| Net assets (liabilities) | $ 220 | $ 18 | $ (316) | $ — | $ (78) |

| | December 31, 2016 | | | | |
|---|---|---|---|---|---|
| | Derivative Assets | | Derivative Liabilities | | |
| | Commodity Contracts | Interest Rate Swaps | Commodity Contracts | Interest Rate Swaps | Total |
| Current assets | $ 350 | $ — | $ — | $ — | $ 350 |
| Noncurrent assets | 46 | 17 | — | 1 | 64 |
| Current liabilities | — | (12) | (330) | (17) | (359) |
| Noncurrent liabilities | — | — | (2) | — | (2) |
| Net assets (liabilities) | $ 396 | $ 5 | $ (332) | $ (16) | $ 53 |

At December 31, 2017 and 2016 , there were no derivative positions accounted for as cash flow or fair value hedges.

The following table presents the pretax effect of derivative gains (losses) on net income, including realized and unrealized effects. Amount represents changes in fair value of positions in the derivative portfolio during the period, as realized amounts related to positions settled are assumed to equal reversals of previously recorded unrealized amounts.

| | Successor | | Predecessor | |
|---|---|---|---|---|
| Derivative (statements of consolidated income (loss) presentation) | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Commodity contracts (Operating revenues) | $ 56 | $ (92) | $ — | $ — |
| Commodity contracts (Fuel, purchased power costs and delivery fees) | 6 | 21 | — | — |
| Commodity contracts (Net gain from commodity hedging and trading activities) | — | — | 194 | 380 |
| Interest rate swaps (Interest expense and related charges) | 2 | (11) | — | — |
| Net gain (loss) | $ 64 | $ (82) | $ 194 | $ 380 |

In conjunction with fresh start reporting, the balances in accumulated other comprehensive income were eliminated from our consolidated balance sheet on the Effective Date. The pretax effect (all losses) on net income and other comprehensive income (OCI) of derivative instruments previously accounted for as cash flow hedges by the Predecessor was immaterial for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 . There were no amounts recognized in OCI for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 .

***Balance Sheet Presentation of Derivatives***

We elect to report derivative assets and liabilities in our consolidated balance sheets on a gross basis without taking into consideration netting arrangements we have with counterparties to those derivatives. We maintain standardized master netting agreements with certain counterparties that allow for the right to offset assets and liabilities and collateral in order to reduce credit exposure between us and the counterparty. These agreements contain specific language related to margin requirements, monthly settlement netting, cross-commodity netting and early termination netting, which is negotiated with the contract counterparty.

Generally, margin deposits that contractually offset these derivative instruments are reported separately in our consolidated balance sheets, with the exception of certain margin amounts related to changes in fair value on certain CME transactions that, beginning in January 2017, are legally characterized as settlement of forward exposure rather than collateral. Margin deposits received from counterparties are primarily used for working capital or other general corporate purposes.

The following tables reconcile our derivative assets and liabilities on a contract basis to net amounts after taking into consideration netting arrangements with counterparties and financial collateral:

| | December 31, 2017 | | | | December 31, 2016 | | | |
|---|---|---|---|---|---|---|---|---|
| | Derivative Assets and Liabilities | Offsetting Instruments (a) | Cash Collateral (Received) Pledged (b) | Net Amounts | Derivative Assets and Liabilities | Offsetting Instruments (a) | Cash Collateral (Received) Pledged (b) | Net Amounts |
| Derivative assets: | | | | | | | | |
| Commodity contracts | $ 220 | $ (113) | $ (1) | $ 106 | $ 396 | $ (193) | $ (20) | $ 183 |
| Interest rate swaps | 18 | — | — | 18 | 5 | — | — | 5 |
| Total derivative assets | 238 | (113) | (1) | 124 | 401 | (193) | (20) | 188 |
| Derivative liabilities: | | | | | | | | |
| Commodity contracts | (316) | 113 | 1 | (202) | (332) | 193 | 136 | (3) |
| Interest rate swaps | — | — | — | — | (16) | — | — | (16) |
| Total derivative liabilities | (316) | 113 | 1 | (202) | (348) | 193 | 136 | (19) |
| Net amounts | $ (78) | $ — | $ — | $ (78) | $ 53 | $ — | $ 116 | $ 169 |

(a) Amounts presented exclude trade accounts receivable and payable related to settled financial instruments.
(b) Represents cash amounts received or pledged pursuant to a master netting arrangement, including fair value-based margin requirements and, to a lesser extent, initial margin requirements.

***Derivative Volumes***

The following table presents the gross notional amounts of derivative volumes at December 31, 2017 and 2016 :

| | December 31, 2017 | December 31, 2016 | |
|---|---|---|---|
| Derivative type | Notional Volume | | Unit of Measure |
| Natural gas (a) | 1,259 | 1,282 | Million MMBtu |
| Electricity | 114,129 | 75,322 | GWh |
| Congestion Revenue Rights (b) | 110,913 | 126,573 | GWh |
| Coal | 2 | 12 | Million U.S. tons |
| Fuel oil | 5 | 34 | Million gallons |
| Uranium | 325 | 25 | Thousand pounds |
| Interest rate swaps – floating/fixed (c) | $ 3,000 | $ 3,000 | Million U.S. dollars |

(a) Represents gross notional forward sales, purchases and options transactions, locational basis swaps and other natural gas transactions.
(b) Represents gross forward purchases associated with instruments used to hedge electricity price differences between settlement points within ERCOT.
(c) Includes notional amounts of interest rate swaps that became effective in January 2017 and have maturity dates through July 2023.

***Credit Risk-Related Contingent Features of Derivatives***

Our derivative contracts may contain certain credit risk-related contingent features that could trigger liquidity requirements in the form of cash collateral, letters of credit or some other form of credit enhancement. Certain of these agreements require the posting of collateral if our credit rating is downgraded by one or more credit rating agencies or include cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants.

The following table presents the commodity derivative liabilities subject to credit risk-related contingent features that are not fully collateralized:

| | December 31, | |
|---|---|---|
| | **2017** | **2016** |
| Fair value of derivative contract liabilities (a) | $ (204) | $ (31) |
| Offsetting fair value under netting arrangements (b) | 103 | 13 |
| Cash collateral and letters of credit | 41 | 1 |
| Liquidity exposure | $ (60) | $ (17) |

(a) Excludes fair value of contracts that contain contingent features that do not provide specific amounts to be posted if features are triggered, including provisions that generally provide the right to request additional collateral (material adverse change, performance assurance and other clauses).
(b) Amounts include the offsetting fair value of in-the-money derivative contracts and net accounts receivable under master netting arrangements.

***Concentrations of Credit Risk Related to Derivatives***

We have concentrations of credit risk with the counterparties to our derivative contracts. At December 31, 2017 , total credit risk exposure to all counterparties related to derivative contracts totaled $361 million (including associated accounts receivable). The net exposure to those counterparties totaled $180 million at December 31, 2017 after taking into effect netting arrangements, setoff provisions and collateral, with the largest net exposure to a single counterparty totaling $63 million . At December 31, 2017 , the credit risk exposure to the banking and financial sector represented 34% of the total credit risk exposure and 24% of the net exposure.

Exposure to banking and financial sector counterparties is considered to be within an acceptable level of risk tolerance because all of this exposure is with counterparties with investment grade credit ratings. However, this concentration increases the risk that a default by any of these counterparties would have a material effect on our financial condition, results of operations and liquidity. The transactions with these counterparties contain certain provisions that would require the counterparties to post collateral in the event of a material downgrade in their credit rating.

We maintain credit risk policies with regard to our counterparties to minimize overall credit risk. These policies authorize specific risk mitigation tools including, but not limited to, use of standardized master agreements that allow for netting of positive and negative exposures associated with a single counterparty. Credit enhancements such as parent guarantees, letters of credit, surety bonds, liens on assets and margin deposits are also utilized. Prospective material changes in the payment history or financial condition of a counterparty or downgrade of its credit quality result in the reassessment of the credit limit with that counterparty. The process can result in the subsequent reduction of the credit limit or a request for additional financial assurances. An event of default by one or more counterparties could subsequently result in termination-related settlement payments that reduce available liquidity if amounts are owed to the counterparties related to the derivative contracts or delays in receipts of expected settlements if the counterparties owe amounts to us.

## 17. PENSION AND OTHER POSTRETIREMENT EMPLOYEE BENEFITS (OPEB) PLANS

On the Effective Date, the EFH Retirement Plan was transferred to Vistra Energy pursuant to a separation agreement between Vistra Energy and EFH Corp. As of the Effective Date, Vistra Energy is the plan sponsor of the Vistra Energy Retirement Plan (the Retirement Plan), which provides benefits to eligible employees of its subsidiaries. Oncor is a participant in the Retirement Plan. As Vistra Energy accounts for its interests in the Retirement Plan as a multiple employer plan, only Vistra Energy's share of the plan assets and obligations are reported in the pension benefit information presented below. After amendments in 2012, employees in the Retirement Plan now consist entirely of active and retired collective bargaining unit employees. The Retirement Plan is a qualified defined benefit pension plan under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and is subject to the provisions of ERISA. The Retirement Plan provides benefits to participants under one of two formulas: (i) a Cash Balance Formula under which participants earn monthly contribution credits based on their compensation and a combination of their age and years of service, plus monthly interest credits or (ii) a Traditional Retirement Plan Formula based on years of service and the average earnings of the three years of highest earnings. Under the Cash Balance Formula, future increases in earnings will not apply to prior service costs. It is our policy to fund the Retirement Plan assets only to the extent required under existing federal regulations.

Vistra Energy and our participating subsidiaries offer other postretirement employee benefits (OPEB) in the form of certain health care and life insurance benefits to eligible retirees and their eligible dependents. The retiree contributions required for such coverage vary based on a formula depending on the retiree's age and years of service.

Effective January 1, 2018, Vistra Energy entered into a contractual arrangement with Oncor whereby the costs associated with providing OPEB coverage for certain retirees (Split Participants) whose employment included service with both the regulated businesses of Oncor (or its predecessors) and the non-regulated businesses of Vistra Energy (or its predecessors) are split between Oncor and Vistra Energy. Prior to January 1, 2018, coverage for Split Participants was provided by the Oncor OPEB plan, with Vistra Energy retaining its portion of the liability for coverage for Split Participants. In addition, Vistra Energy is the sponsor of an OPEB plan that certain EFH Corp. retirees participate in. As Vistra Energy accounts for its interest in these OPEB plans as multiple employer plans, only Vistra Energy's share of the plan assets and obligations are reported in the OPEB information presented below.

***Pension and OPEB Costs***

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Pension costs | $ 6 | $ 2 | $ 4 | $ 8 |
| OPEB costs | 6 | 2 | — | 3 |
| Total benefit costs recognized as expense | $ 12 | $ 4 | $ 4 | $ 11 |

***Market-Related Value of Assets Held in Postretirement Benefit Trusts***

We use the calculated value method to determine the market-related value of the assets held in the trust for purposes of calculating pension costs. We include the realized and unrealized gains or losses in the market-related value of assets over a rolling four-year period. Each year, 25% of such gains and losses for the current year and for each of the preceding three years is included in the market-related value. Each year, the market-related value of assets is increased for contributions to the plan and investment income and is decreased for benefit payments and expenses for that year.

***Detailed Information Regarding Pension Benefits***

The following information is based on a December 31, 2017 measurement date:

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| *Assumptions Used to Determine Net Periodic Pension Cost:* | | |
| Discount rate | 4.31% | 3.79% |
| Expected return on plan assets | 4.86% | 4.89% |
| Expected rate of compensation increase | 3.50% | 3.50% |
| *Components of Net Pension Cost:* | | |
| Service cost | $ 5 | $ 2 |
| Interest cost | 6 | 1 |
| Expected return on assets | (5) | (1) |
| Net periodic pension cost | $ 6 | $ 2 |
| *Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income:* | | |
| Net (gain) loss | $ 3 | $ (4) |
| Total recognized in net periodic benefit cost and other comprehensive income | $ 9 | $ (2) |
| *Assumptions Used to Determine Benefit Obligations:* | | |
| Discount rate | 3.74% | 4.31% |
| Expected rate of compensation increase | 3.62% | 3.50% |

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| *Change in Pension Obligation:* | | |
| Projected benefit obligation at beginning of period | $ 144 | $ 154 |
| Service cost | 5 | 2 |
| Interest cost | 6 | 1 |
| Actuarial (gain) loss | 13 | (12) |
| Benefits paid | (5) | (1) |
| Projected benefit obligation at end of year | $ 163 | $ 144 |
| Accumulated benefit obligation at end of year | $ 157 | $ 136 |
| *Change in Plan Assets:* | | |
| Fair value of assets at beginning of period | $ 117 | $ 124 |
| Actual gain (loss) on assets | 16 | (6) |
| Benefits paid | (5) | (1) |
| Fair value of assets at end of year | $ 128 | $ 117 |
| *Funded Status:* | | |
| Projected pension benefit obligation | $ (163) | $ (144) |
| Fair value of assets | 128 | 117 |
| Funded status at end of year | $ (35) | $ (27) |
| *Amounts Recognized in the Balance Sheet Consist of:* | | |
| Other current liabilities | $ — | $ — |
| Other noncurrent liabilities | (35) | (27) |
| Net liability recognized | $ (35) | $ (27) |
| *Amounts Recognized in Accumulated Other Comprehensive Income Consist of:* | | |
| Net gain | $ 1 | $ 4 |

The following table provides information regarding pension plans with projected benefit obligation (PBO) and accumulated benefit obligation (ABO) in excess of the fair value of plan assets.

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| *Pension Plans with PBO and ABO in Excess Of Plan Assets:* | | |
| Projected benefit obligations | $ 163 | $ 144 |
| Accumulated benefit obligation | $ 157 | $ 136 |
| Plan assets | $ 128 | $ 117 |

***Pension Plan Investment Strategy and Asset Allocations***

Our investment objective for the Retirement Plan is to invest in a suitable mix of assets to meet the future benefit obligations at an acceptable level of risk, while minimizing the volatility of contributions. Fixed income securities held primarily consist of corporate bonds from a diversified range of companies, U.S. Treasuries and agency securities and money market instruments. Equity securities are held to enhance returns by participating in a wide range of investment opportunities. International equity securities are used to further diversify the equity portfolio and may include investments in both developed and emerging markets.

The target asset allocation ranges of pension plan investments by asset category are as follows:

| **Asset Category:** | **Target Allocation Ranges** |
|---|---|
| Fixed income | 74% - 86% |
| U.S. equities | 8% - 14% |
| International equities | 6% - 12% |

***Expected Long-Term Rate of Return on Assets Assumption***

The Retirement Plan strategic asset allocation is determined in conjunction with the plan's advisors and utilizes a comprehensive Asset-Liability modeling approach to evaluate potential long-term outcomes of various investment strategies. The study incorporates long-term rate of return assumptions for each asset class based on historical and future expected asset class returns, current market conditions, rate of inflation, current prospects for economic growth, and taking into account the diversification benefits of investing in multiple asset classes and potential benefits of employing active investment management.

| | **Retirement Plan** |
|---|---|
| **Asset Class:** | **Expected Long-Term Rate of Return** |
| U.S. equity securities | 6.4% |
| International equity securities | 7.3% |
| Fixed income securities | 3.9% |
| Weighted average | 4.6% |

***Fair Value Measurement of Pension Plan Assets***

At December 31, 2017 , the Retirement Plan assets measured at fair value on a recurring basis consisted of the following:

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| **Asset Category:** | | |
| Level 2 valuations (see Note 15): | | |
| Interest-bearing cash | $ (7) | $ (4) |
| Fixed income securities: | | |
| Corporate bonds (a) | 65 | 54 |
| U.S. Treasuries | 29 | 30 |
| Other (b) | 7 | 6 |
| Total assets categorized as Level 2 | 94 | 86 |
| Assets measured at net asset value (c): | | |
| Interest-bearing cash | 2 | 2 |
| Equity securities: | | |
| U.S. | 14 | 14 |
| International | 13 | 9 |
| Fixed income securities: | | |
| Corporate bonds (a) | 5 | 6 |
| Total assets measured at net asset value | 34 | 31 |
| Total assets | $ 128 | $ 117 |

(a) Substantially all corporate bonds are rated investment grade by a major ratings agency such as Moody's.
(b) Other consists primarily of taxable municipal bonds.
(c) Certain investments measured at fair value using the net asset value per share (or its equivalent) have not been classified in the fair value hierarchy. The fair value amounts presented in this line are intended to permit reconciliation of the fair value hierarchy to total Vistra Retirement Plan assets.

***Detailed Information Regarding Postretirement Benefits Other Than Pensions***

The following OPEB information is based on a December 31, 2017 measurement date:

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| *Assumptions Used to Determine Net Periodic Benefit Cost:* | | |
| Discount rate (Vistra Energy Plan) | 4.11% | 4.00% |
| Discount rate (Oncor Plan) | 4.18% | 3.69% |
| *Components of Net Postretirement Benefit Cost:* | | |
| Service cost | $ 2 | $ 1 |
| Interest cost | 4 | 1 |
| Plan amendments (a) | — | (4) |
| Net periodic OPEB cost (income) | $ 6 | $ (2) |
| *Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income:* | | |
| Net (gain) loss and prior service (credit) cost | $ 26 | $ (5) |
| Total recognized in net periodic benefit cost and other comprehensive income | $ 32 | $ (7) |
| *Assumptions Used to Determine Benefit Obligations at Period End:* | | |
| Discount rate (Vistra Energy Plan) | 3.67% | 4.11% |
| Discount rate (Split-Participant Plan) | 3.67% | —% |
| Discount rate (Oncor Plan) | —% | 4.18% |

___________

(a) Curtailment gain recognized as other income in the statements of consolidated income (loss) as a result of discontinued life insurance benefits for active employees.

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| *Change in Postretirement Benefit Obligation:* | | |
| Benefit obligation at beginning of year | $ 88 | $ 97 |
| Service cost | 2 | 1 |
| Interest cost | 4 | 1 |
| Participant contributions | 2 | 1 |
| Plan amendments (a) | 11 | (4) |
| Actuarial (gain) loss | 15 | (5) |
| Benefits paid | (7) | (3) |
| Benefit obligation at end of year | $ 115 | $ 88 |
| *Change in Plan Assets:* | | |
| Fair value of assets at beginning of year | $ — | $ — |
| Employer contributions | 5 | 1 |
| Participant contributions | 2 | 1 |
| Benefits paid | (7) | (2) |
| Fair value of assets at end of year | $ — | $ — |
| *Funded Status:* | | |
| Benefit obligation | $ 115 | $ 88 |
| Funded status at end of year | $ 115 | $ 88 |
| *Amounts Recognized on the Balance Sheet Consist of:* | | |
| Other current liabilities | $ 6 | $ 5 |
| Other noncurrent liabilities | 109 | 83 |
| Net liability recognized | $ 115 | $ 88 |
| *Amounts Recognized in Accumulated Other Comprehensive Income Consist of:* | | |
| Net loss and prior service cost | $ 20 | $ 5 |

(a) For the year ended December 31, 2017, plan amendments relate to the contractual arrangement with Oncor covering Split Participants. For the period from October 3, 2016 through December 31, 2016, a curtailment gain was recognized as other income in the statements of consolidated income (loss) as a result of discontinued life insurance benefits for active employees.

The following tables provide information regarding the assumed health care cost trend rates.

| | Successor | |
|---|---|---|
| | December 31, 2017 | December 31, 2016 |
| *Assumed Health Care Cost Trend Rates-Not Medicare Eligible:* | | |
| Health care cost trend rate assumed for next year | 7.00% | 5.80% |
| Rate to which the cost trend is expected to decline (the ultimate trend rate) | 4.50% | 5.00% |
| Year that the rate reaches the ultimate trend rate | 2026 | 2024 |
| *Assumed Health Care Cost Trend Rates-Medicare Advantage Eligible (2017) / Medicare Eligible (2016):* | | |
| Health care cost trend rate assumed for next year | 10.66% | 5.70% |
| Rate to which the cost trend is expected to decline (the ultimate trend rate) | 4.50% | 5.00% |
| Year that the rate reaches the ultimate trend rate | 2026 | 2024 |

| | 1-Percentage Point Increase | 1-Percentage Point Decrease |
|---|---|---|
| *Sensitivity Analysis of Assumed Health Care Cost Trend Rates :* | | |
| Effect on accumulated postretirement obligation | $ 2 | $ (2) |
| Effect on postretirement benefits cost | $ — | $ — |

***Fair Value Measurement of OPEB Plan Assets***

At December 31, 2017 , the Vistra Energy OPEB plan had no plan assets.

***Significant Concentrations of Risk***

The plans' investments are exposed to risks such as interest rate, capital market and credit risks. We seek to optimize return on investment consistent with levels of liquidity and investment risk which are prudent and reasonable, given prevailing capital market conditions and other factors specific to us. While we recognize the importance of return, investments will be diversified in order to minimize the risk of large losses unless, under the circumstances, it is clearly prudent not to do so. There are also various restrictions and guidelines in place including limitations on types of investments allowed and portfolio weightings for certain investment securities to assist in the mitigation of the risk of large losses.

***Assumed Discount Rate***

We selected the assumed discount rate using the Aon Hewitt AA Above Median yield curve, which is based on corporate bond yields and at December 31, 2017 consisted of 391 corporate bonds with an average rating of AA using Moody's, Standard & Poor's Rating Services and Fitch Ratings, Ltd. ratings.

***Amortization in 2018***

We estimate amortization of the net actuarial gain for the Retirement Plan from accumulated other comprehensive income into net periodic benefit cost will be immaterial. We estimate amortization of the net actuarial gain and prior service cost for the OPEB plan from accumulated other comprehensive income into net periodic benefit cost will be $3 million .

***Contributions***

*Successor* — No contributions were made to the Retirement Plan for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, and none are expected to be made in 2018 . OPEB plan funding for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 totaled $5 million and $1 million , respectively, and funding in 2018 is expected to total $6 million .

*Predecessor* — In September 2016, a cash contribution totaling $2 million was made to the EFH Retirement Plan, all of which was contributed by our Predecessor. In December 2015, a cash contribution totaling $67 million was made to the EFH Retirement Plan assets, of which $51 million was contributed by Oncor and $16 million was contributed by our Predecessor. Each of these contributions resulted in the Retirement Plan being fully funded as calculated under the provisions of ERISA. As a result of the Bankruptcy Filing, participants in the EFH Retirement Plan who chose to retire would not be eligible for the lump sum payout option under the EFH Retirement Plan unless the EFH Retirement Plan was fully funded. OPEB plan funding for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 totaled $3 million and $8 million , respectively.

***Future Benefit Payments***

Estimated future benefit payments to beneficiaries are as follows:

| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023-27 |
|---|---|---|---|---|---|---|
| Pension benefits | $ 11 | $ 8 | $ 8 | $ 8 | $ 9 | $ 50 |
| OPEB | $ 6 | $ 7 | $ 8 | $ 8 | $ 8 | $ 39 |

### *Thrift Plan*

Our employees may participate in a qualified savings plan (the Thrift Plan). This plan is a participant-directed defined contribution plan intended to qualify under Section 401(a) of the Code, and is subject to the provisions of ERISA. Under the terms of the Thrift Plan, employees who do not earn more than the IRS threshold compensation limit used to determine highly compensated employees may contribute, through pre-tax salary deferrals and/or after-tax payroll deductions, the lesser of 75% of their regular salary or wages or the maximum amount permitted under applicable law. Employees who earn more than such threshold may contribute from 1% to 20% of their regular salary or wages. Employer matching contributions are also made in an amount equal to 100% ( 75% for employees covered under the Traditional Retirement Plan Formula) of the first 6% of employee contributions. Employer matching contributions are made in cash and may be allocated by participants to any of the plan's investment options.

Employer contributions to the Thrift Plan totaled $19 million , $5 million , $16 million and $21 million for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively.

## 18. STOCK-BASED COMPENSATION

### *Vistra Energy 2016 Omnibus Incentive Plan*

On the Effective Date, the Vistra Energy board of directors (Board) adopted the 2016 Omnibus Incentive Plan (2016 Incentive Plan), under which an aggregate of 22,500,000 shares of our common stock were reserved for issuance as equity-based awards to our non-employee directors, employees, and certain other persons. The Board or any committee duly authorized by the Board will administer the 2016 Incentive Plan and has broad authority under the 2016 Incentive Plan to, among other things: (a) select participants, (b) determine the types of awards that participants are to receive and the number of shares that are to be subject to such awards and (c) establish the terms and conditions of awards, including the price (if any) to be paid for the shares of the award. The types of awards that may be granted under the 2016 Incentive Plan include stock options, RSUs, restricted stock, performance awards and other forms of awards granted or denominated in shares of Vistra Energy common stock, as well as certain cash-based awards.

If any stock option or other stock-based award granted under the 2016 Incentive Plan expires, terminates or is canceled for any reason without having been exercised in full, the number of shares of Vistra Energy common stock underlying any unexercised award shall again be available for the purpose of awards under the 2016 Incentive Plan. If any shares of restricted stock, performance awards or other stock-based awards denominated in shares of Vistra Energy common stock awarded under the 2016 Incentive Plan are forfeited for any reason, the number of forfeited shares shall again be available for purposes of awards under the 2016 Incentive Plan. Any award under the 2016 Incentive Plan settled in cash shall not be counted against the maximum share limitation.

As is customary in incentive plans of this nature, each share limit and the number and kind of shares available under the 2016 Incentive Plan and any outstanding awards, as well as the exercise or purchase price of awards, and performance targets under certain types of performance-based awards, are required to be adjusted in the event of certain reorganizations, mergers, combinations, recapitalizations, stock splits, stock dividends or other similar events that change the number or kind of shares outstanding, and extraordinary dividends or distributions of property to the Vistra Energy stockholders.

Stock-based compensation expense is reported as SG&A in the statement of consolidated net income (loss) as follows:

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Total stock-based compensation expense | $ 19 | $ 3 |
| Income tax benefit | (7) | (1) |
| Stock based-compensation expense, net of tax | $ 12 | $ 2 |

***Stock Options***

The fair value of each stock option is estimated on the date of grant using a Black-Scholes option-pricing model. The risk-free interest rate used in the option valuation model was based on yields available on the grant dates for U.S. Treasury Strips with maturity consistent with the expected life assumption. The expected term of the option represents the period of time that options granted are expected to be outstanding and is based on the SEC Simplified Method (midpoint of average vesting time and contractual term). Expected volatility is based on an average of the historical, daily volatility of a peer group selected by Vistra Energy over a period consistent with the expected life assumption ending on the grant date. We assumed no dividend yield in the valuation of the options. These options may be exercised over either three- or four-year graded vesting periods and will expire 10 years from the grant date.

The 2016 Incentive Plan includes an anti-dilutive provision that requires any outstanding option awards to be adjusted for the effect of equity restructurings. In March 2017, the board of directors of Vistra Energy declared that the exercise price of each outstanding option be reduced by $2.32 , the amount per share of common stock related to the Special Dividend (see Note 14 ).

Stock options outstanding at December 31, 2017 are all held by current employees. The following table summarizes our stock option activity:

| | Successor | | | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | | | |
| | Stock Options (in thousands) | Weighted Average Exercise Price | Weighted Average Remaining Contractual Term (Years) | Aggregate Intrinsic Value (in millions) |
| Total outstanding at beginning of period | 7,357 | $ 15.81 | 9.8 | $ — |
| Granted | 1,412 | $ 18.86 | | |
| Exercised | (281) | $ 13.41 | | |
| Forfeited or expired | (352) | $ 13.76 | | |
| Total outstanding at end of period | 8,136 | $ 14.44 | 9.0 | $ 32.4 |
| Expected to vest | 6,618 | $ 14.65 | 9.1 | $ 25.1 |

At December 31, 2017 , $30 million of unrecognized compensation cost related to unvested stock options granted under the 2016 Incentive Plan are expected to be recognized over a weighted average period of approximately 3 years .

***Restricted Stock Units***

The following table summarizes our restricted stock unit activity:

| | Successor | | | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | | | |
| | Restricted Stock Units (in thousands) | Weighted Average Grant Date Fair Value | Weighted Average Remaining Contractual Term (Years) | Aggregate Intrinsic Value (in millions) |
| Total outstanding at beginning of period | 2,159 | $ 15.79 | 2.3 | $ 33.5 |
| Granted | 861 | $ 18.84 | | |
| Exercised | (538) | $ 15.76 | | |
| Forfeited or expired | (107) | $ 15.85 | | |
| Total outstanding at end of period | 2,375 | $ 16.91 | 1.9 | $ 43.5 |
| Expected to vest | 2,375 | $ 16.91 | 1.9 | $ 43.5 |

At December 31, 2017 , $37 million of unrecognized compensation cost related to unvested restricted stock units granted under the 2016 Incentive Plan are expected to be recognized over a weighted average period of approximately 3 years .

***Performance Stock Units***

In October 2017, we issued Performance Stock Units (PSUs) to certain members of management. As of December 31, 2017, we had not yet established the significant terms of the PSUs relevant to vesting (scorecard and metric design, thresholds, and targets); therefore, a grant date for financial accounting purposes has not occurred.

## 19. RELATED PARTY TRANSACTIONS

***Successor***

In connection with Emergence, we entered into agreements with certain of our affiliates and with parties who received shares of common stock and TRA Rights in exchange for their claims.

*Registration Rights Agreement*

Pursuant to the Plan of Reorganization, on the Effective Date, we entered into a Registration Rights Agreement (the Registration Rights Agreement) with certain selling stockholders providing for registration of the resale of the Vistra Energy common stock held by such selling stockholders.

In December 2016, we filed a Form S-1 registration statement with the SEC to register for resale the shares of Vistra Energy common stock held by certain significant stockholders pursuant to the Registration Rights Agreement. The registration statement was amended in February 2017, April 2017 and May 2017. The registration statement was declared effective by the SEC in May 2017. Among other things, under the terms of the Registration Rights Agreement:

- we will be required to use reasonable best efforts to convert the Form S-1 registration statement into a registration statement on Form S-3 as soon as reasonably practicable after we become eligible to do so and to have such Form S-3 declared effective as promptly as practicable (but in no event more than 30 days after it is filed with the SEC);
- if we propose to file certain types of registration statements under the Securities Act with respect to an offering of equity securities, we will be required to use our reasonable best efforts to offer the other parties to the Registration Rights Agreement the opportunity to register all or part of their shares on the terms and conditions set forth in the Registration Rights Agreement; and
- the selling stockholders received the right, subject to certain conditions and exceptions, to request that we file registration statements or amend or supplement registration statements, with the SEC for an underwritten offering of all or part of their respective shares of Vistra Energy common stock (a Demand Registration), and the Company is required to cause any such registration statement or amendment or supplement (a) to be filed with the SEC promptly and, in any event, on or before the date that is 45 days , in the case of a registration statement on Form S-1, or 30 days , in the case of a registration statement on Form S-3, after we receive the written request from the relevant selling stockholders to effectuate the Demand Registration and (b) to become effective as promptly as reasonably practicable and in any event no later than 120 days after it is initially filed.

All expenses of registration under the Registration Rights Agreement, including the legal fees of one counsel retained by or on behalf of the selling stockholders, will be paid by us. Legal fee expenses paid or accrued by Vistra Energy on behalf of the selling stockholders totaled less than $1 million during the year ended December 31, 2017 .

*Tax Receivable Agreement*

On the Effective Date, Vistra Energy entered into the TRA with a transfer agent on behalf of certain former first lien creditors of TCEH. See Note 9 for discussion of the TRA.

***Predecessor***

See Note 5 for a discussion of certain agreements entered into on the Effective Date between EFH Corp. and Vistra Energy with respect to the separation of the entities, including a separation agreement, a transition services agreement, a tax matters agreement and a settlement agreement.

The following represent our Predecessor's significant related-party transactions. As of the Effective Date, pursuant to the Plan of Reorganization, the Sponsor Group, EFH Corp., EFIH, Oncor Holdings and Oncor ceased being affiliates of Vistra Energy and its subsidiaries, including the TCEH Debtors and the Contributed EFH Debtors.

- Our retail operations (and prior to the Effective Date, our Predecessor) pay Oncor for services it provides, principally the delivery of electricity. Expenses recorded for these services, reported in fuel, purchased power costs and delivery fees, totaled $700 million and $955 million for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively.
- A former subsidiary of EFH Corp. billed our Predecessor's subsidiaries for information technology, financial, accounting and other administrative services at cost. These charges, which are largely settled in cash and primarily reported in SG&A expenses, totaled $157 million and $205 million for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively.
- Under Texas regulatory provisions, the trust fund for decommissioning the Comanche Peak nuclear generation facility is funded by a delivery fee surcharge billed to REPs by Oncor, as collection agent, and remitted monthly to Vistra Energy (and prior to the Effective Date, our Predecessor) for contribution to the trust fund with the intent that the trust fund assets, reported in other investments in our consolidated balance sheets, will ultimately be sufficient to fund the future decommissioning liability, reported in asset retirement obligations in our consolidated balance sheets. The delivery fee surcharges remitted to our Predecessor totaled $15 million and $17 million for the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively. Income and expenses associated with the trust fund and the decommissioning liability incurred by Vistra Energy (and prior to the Effective Date, our Predecessor) are offset by a net change in a receivable/payable that ultimately will be settled through changes in Oncor's delivery fee rates.
- EFH Corp. files consolidated federal income tax and Texas state margin tax returns that included our results prior to the Effective Date; however, under a Federal and State Income Tax Allocation Agreement, our federal income tax and Texas margin tax expense and related balance sheet amounts, including income taxes payable to or receivable from EFH Corp., were recorded as if our Predecessor filed its own corporate income tax return. For the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , our Predecessor made income tax payments to EFH Corp. totaling $22 million and $29 million , respectively. In 2015, $609 million of income tax liability was eliminated under the terms of the Settlement Agreement. See Note 8 for discussion of cessation of payment of federal income taxes pursuant to the Settlement Agreement.
- Contributions to the EFH Corp. retirement plan by both Oncor and TCEH in 2014, 2015 and 2016 resulted in the EFH Corp. retirement plan being fully funded as calculated under the provisions of the Employee Retirement Income Security Act of 1974, as amended (ERISA). In September 2016, a cash contribution totaling $2 million was made to the EFH Corp. retirement plan, all of which was contributed by TCEH, which resulted in the EFH Retirement Plan continuing to be fully funded as calculated under the provisions of ERISA. On the Effective Date, the EFH Retirement Plan was transferred to Vistra Energy pursuant to a separation agreement between Vistra Energy and EFH Corp.
- In 2007, TCEH entered into the TCEH Senior Secured Facilities with syndicates of financial institutions and other lenders. These syndicates included affiliates of GS Capital Partners, which is a member of the Sponsor Group. Affiliates of each member of the Sponsor Group have from time to time engaged in commercial banking transactions with TCEH and/or provided financial advisory services to TCEH, in each case in the normal course of business.
- Affiliates of GS Capital Partners were parties to certain commodity and interest rate hedging transactions with our Predecessor in the normal course of business.
- Affiliates of the Sponsor Group have sold or acquired, and in the future may sell or acquire, debt or debt securities issued by our Predecessor in open market transactions or through loan syndications.
- As a result of debt repurchase and exchange transactions in 2009 through 2011, EFH Corp. and EFIH held TCEH debt securities totaling $382 million as of the Petition Date. These notes payable were classified as LSTC. The amounts of TCEH debt held by EFIH or EFH Corp. were eliminated as a result of the Settlement Agreement approved by the Bankruptcy Court in December 2015 (see Note 5 ). In conjunction with the Settlement Agreement approved by the Bankruptcy Court in December 2015, EFH Corp. and EFIH waived their rights to the claims associated with these debt securities resulting in a gain recorded in reorganization items (see Note 5 ). Interest expense on the notes totaled $1 million for the year ended December 31, 2015 . Contractual interest, not paid or recorded, totaled $37 million for the year ended December 31, 2015 . See Note 10 .

## 20. SEGMENT INFORMATION

The operations of Vistra Energy are aligned into three reportable business segments: Wholesale Generation, Retail Electricity and Asset Closure. Our chief operating decision maker reviews the results of these three segments separately and allocates resources to the respective segments as part of our strategic operations. The Wholesale Generation and Retail Electricity businesses offer different products or services and involve different risks.

The Wholesale Generation segment is engaged in electricity generation, wholesale energy sales and purchases, commodity risk management activities, fuel production and fuel logistics management, all largely in the ERCOT market. These activities are substantially all conducted by Luminant.

The Retail Electricity segment is engaged in retail sales of electricity and related services to residential, commercial and industrial customers, all largely in the ERCOT market. These activities are substantially all conducted by TXU Energy.

As discussed in Note 1, the Asset Closure segment was established effective January 1, 2018; however, these financial statements have been recast to reflect the changes resulting from the establishment of the Asset Closure segment. The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines. Separately reporting the Asset Closure segment provides management with better information related to the performance and earnings power of Vistra Energy's ongoing operations and facilitates management's focus on minimizing the cost associated with decommissioning and reclamation of retired plants and mines. We have recast information from prior periods to reflect this change in reportable segments. We have not allocated any unrealized gains or losses on hedging activities to the Asset Closure segment for the generation plants that were retired in January and February 2018.

Corporate and Other represents the remaining non-segment operations consisting primarily of general corporate expenses, interest, taxes and other expenses related to our support functions that provide shared services to our Wholesale Generation and Retail Electricity segments.

The accounting policies of the business segments are the same as those described in the summary of significant accounting policies in Note 1 . Our chief operating decision maker uses more than one measure to assess segment performance, including reported segment operating income and segment net income (loss), which is the measure most comparable to consolidated net income (loss) prepared based on GAAP. We account for intersegment sales and transfers as if the sales or transfers were to third parties, that is, at current market prices. Certain shared services costs are allocated to the segments.

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Operating revenues (a) | | |
| Wholesale Generation | $ 1,794 | $ 212 |
| Retail Electricity | 4,058 | 912 |
| Asset Closure | 964 | 238 |
| Eliminations | (1,386) | (171) |
| Consolidated operating revenues | $ 5,430 | $ 1,191 |
| Depreciation and amortization | | |
| Wholesale Generation | $ 229 | $ 53 |
| Retail Electricity | 430 | 153 |
| Asset Closure | 1 | — |
| Corporate and Other | 40 | 11 |
| Eliminations | (1) | $ (1) |
| Consolidated depreciation and amortization | $ 699 | $ 216 |

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Operating income (loss) | | |
| Wholesale Generation | $ (118) | $ (271) |
| Retail Electricity | 461 | 111 |
| Asset Closure | (68) | 16 |
| Corporate and Other | (77) | (17) |
| Consolidated operating income (loss) | $ 198 | $ (161) |
| Interest expense and related charges | | |
| Wholesale Generation | $ 21 | $ (1) |
| Corporate and Other | 252 | 66 |
| Eliminations | (80) | (5) |
| Consolidated interest expense and related charges | $ 193 | $ 60 |
| Income tax expense (benefit)(all Corporate and Other) | $ 504 | $ (70) |
| Net income (loss) | | |
| Wholesale Generation | $ (114) | $ (268) |
| Retail Electricity | 495 | 114 |
| Asset Closure | (63) | 17 |
| Corporate and Other | (572) | (26) |
| Consolidated net income (loss) | $ (254) | $ (163) |
| Capital expenditures | | |
| Wholesale Generation | $ 150 | $ 77 |
| Retail Electricity | — | 5 |
| Asset Closure | — | 7 |
| Corporate and Other | 26 | — |
| Consolidated capital expenditures | $ 176 | $ 89 |

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(a) For the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, includes third-party unrealized net gains (losses) from mark-to-market valuations of commodity positions of $(151) million and $(182) million , respectively, recorded to the Wholesale Generation segment and $18 million and $(6) million , respectively, recorded to the Retail Electricity segment. In addition, for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, unrealized net gains (losses) with affiliate of $(154) million and $(113) million , respectively, were recorded to operating revenues for the Wholesale Generation segment and corresponding unrealized net gains (losses) with affiliate of $154 million and $113 million , respectively, were recorded to fuel, purchased power costs and delivery fees for the Retail Electricity segment, with no impact to consolidated results.

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Total assets | | |
| Wholesale Generation | $ 6,834 | $ 6,673 |
| Retail Electricity | 6,156 | 5,753 |
| Asset Closure | 235 | 279 |
| Corporate and Other and Eliminations | 1,375 | 2,462 |
| Consolidated total assets | $ 14,600 | $ 15,167 |

Prior to the Effective Date, our Predecessor's chief operating decision maker reviewed the retail electricity, wholesale generation and commodity risk management activities together. Consequently, there were no reportable business segments for TCEH.

## 21.SUPPLEMENTARY FINANCIAL INFORMATION

***Other Income and Deductions***

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Other income: | | | | |
| Office space sublease rental income (a) | $ 11 | $ 2 | $ — | $ — |
| Mineral rights royalty income (b) | 3 | 1 | 3 | 4 |
| Sale of land (b) | 4 | — | — | — |
| Curtailment gain on employee benefit plans (a) | — | 4 | — | — |
| Insurance settlement | — | — | 9 | — |
| Interest income | 15 | 1 | 3 | 1 |
| All other | 4 | 2 | 4 | 13 |
| Total other income | $ 37 | $ 10 | $ 19 | $ 18 |
| Other deductions: | | | | |
| Write-off of generation equipment (b) | 2 | — | 45 | — |
| Adjustment to asbestos liability | — | — | 11 | — |
| Impairment of favorable purchase contracts (Note 7) | — | — | — | 8 |
| Impairment of emission allowances (Note 7) | — | — | — | 55 |
| Impairment of mining development costs | — | — | — | 19 |
| All other | 3 | — | 19 | 11 |
| Total other deductions | $ 5 | $ — | $ 75 | $ 93 |

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(a) Reported in Corporate and Other non-segment (Successor period only).
(b) Reported in Wholesale Generation segment (Successor period only).

***Restricted Cash***

| | December 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| | Current Assets | Noncurrent Assets | Current Assets | Noncurrent Assets |
| Amounts related to the Vistra Operations Credit Facilities (Note 12) | $ — | $ 500 | $ — | $ 650 |
| Amounts related to restructuring escrow accounts | 59 | — | 90 | — |
| Other | — | — | 5 | — |
| Total restricted cash | $ 59 | $ 500 | $ 95 | $ 650 |

***Trade Accounts Receivable***

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Wholesale and retail trade accounts receivable | $ 596 | $ 622 |
| Allowance for uncollectible accounts | (14) | (10) |
| Trade accounts receivable — net | $ 582 | $ 612 |

Gross trade accounts receivable at December 31, 2017 and 2016 included unbilled retail revenues of $251 million and $225 million , respectively.

***Allowance for Uncollectible Accounts Receivable***

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Allowance for uncollectible accounts receivable at beginning of period | $ 10 | $ — | $ 9 | $ 15 |
| Increase for bad debt expense | 43 | 10 | 20 | 34 |
| Decrease for account write-offs | (39) | — | (16) | (40) |
| Allowance for uncollectible accounts receivable at end of period | $ 14 | $ 10 | $ 13 | $ 9 |

***Inventories by Major Category***

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Materials and supplies | $ 149 | $ 173 |
| Fuel stock | 83 | 88 |
| Natural gas in storage | 21 | 24 |
| Total inventories | $ 253 | $ 285 |

***Other Investments***

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Nuclear plant decommissioning trust | $ 1,188 | $ 1,012 |
| Land | 49 | 49 |
| Miscellaneous other | 3 | 3 |
| Total other investments | $ 1,240 | $ 1,064 |

***Nuclear Decommissioning Trust*** — Investments in a trust that will be used to fund the costs to decommission the Comanche Peak nuclear generation plant are carried at fair value. Decommissioning costs are being recovered from Oncor's customers as a delivery fee surcharge over the life of the plant and deposited by Vistra Energy (and prior to the Effective Date, a subsidiary of TCEH) in the trust fund. Income and expense associated with the trust fund and the decommissioning liability are offset by a corresponding change in a receivable/payable (currently a receivable reported in noncurrent assets) that will ultimately be settled through changes in Oncor's delivery fees rates. The nuclear decommissioning trust fund was not a debtor in the Chapter 11 Cases. A summary of investments in the fund follows:

| | December 31, 2017 | | | |
|---|---|---|---|---|
| | Cost (a) | Unrealized gain | Unrealized loss | Fair market value |
| Debt securities (b) | $ 418 | $ 14 | $ (2) | $ 430 |
| Equity securities (c) | 265 | 495 | (2) | 758 |
| Total | $ 683 | $ 509 | $ (4) | $ 1,188 |

| | December 31, 2016 | | | |
|---|---|---|---|---|
| | Cost (a) | Unrealized gain | Unrealized loss | Fair market value |
| Debt securities (b) | $ 333 | $ 10 | $ (3) | $ 340 |
| Equity securities (c) | 309 | 368 | (5) | 672 |
| Total | $ 642 | $ 378 | $ (8) | $ 1,012 |

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(a) Includes realized gains and losses on securities sold.
(b) The investment objective for debt securities is to invest in a diversified tax efficient portfolio with an overall portfolio rating of AA or above as graded by S&P or Aa2 by Moody's Investors Services, Inc. The debt securities are heavily weighted with government and municipal bonds and investment grade corporate bonds. The debt securities had an average coupon rate of 3.55% and 3.56% at December 31, 2017 and 2016 , respectively, and an average maturity of 9 years at both December 31, 2017 and 2016 .
(c) The investment objective for equity securities is to invest tax efficiently and to match the performance of the S&P 500 Index.

Debt securities held at December 31, 2017 mature as follows: $111 million in one to 5 years, $99 million in five to 10 years and $220 million after 10 years.

The following table summarizes proceeds from sales of available-for-sale securities and the related realized gains and losses from such sales.

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Realized gains | $ 9 | $ 1 | $ 3 | $ 1 |
| Realized losses | $ (11) | $ — | $ (2) | $ (1) |
| Proceeds from sales of securities | $ 252 | $ 25 | $ 201 | $ 401 |
| Investments in securities | $ (272) | $ (30) | $ (215) | $ (418) |

***Property, Plant and Equipment***

| | December 31, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| Wholesale Generation: | | | | |
| Generation and mining | $ | 4,501 | $ | 3,997 |
| Retail Electricity | | 5 | | 3 |
| Corporate and Other | | 120 | | 107 |
| Total | | 4,626 | | 4,107 |
| Less accumulated depreciation | | (282) | | (54) |
| Net of accumulated depreciation | | 4,344 | | 4,053 |
| Nuclear fuel (net of accumulated amortization of $111 million and $31 million) | | 158 | | 166 |
| Construction work in progress: | | | | |
| Wholesale Generation | | 312 | | 210 |
| Retail Electricity | | — | | 6 |
| Corporate and Other | | 6 | | 8 |
| Total construction work in progress | | 318 | | 224 |
| Property, plant and equipment — net | $ | 4,820 | $ | 4,443 |

Depreciation expense totaled $236 million , $54 million , $401 million and $767 million for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively.

Our property, plant and equipment consists of our power generation assets, related mining assets, information system hardware, capitalized corporate office lease space and other leasehold improvements. At December 31, 2017 , the capital lease for the building totaled $65 million with accumulated depreciation of $3 million . The estimated remaining useful lives range from 2 to 36 years for our property, plant and equipment.

***Asset Retirement and Mining Reclamation Obligations (ARO)***

These liabilities primarily relate to nuclear generation plant decommissioning, land reclamation related to lignite mining, removal of lignite/coal ash treatment facilities and generation plant asbestos removal and disposal costs. There is no earnings impact with respect to changes in the nuclear plant decommissioning liability, as all costs are recoverable through the regulatory process as part of delivery fees charged by Oncor. As part of fresh start reporting, new fair values were established for all AROs for the Successor.

At December 31, 2017 , the carrying value of our ARO related to our nuclear generation plant decommissioning totaled $1.233 billion , which exceeds the fair value of the assets contained in the nuclear decommissioning trust. Since the costs to ultimately decommission that plant are recoverable through the regulatory rate making process as part of Oncor's delivery fees, a corresponding regulatory asset has been recorded to our consolidated balance sheet of $45 million in other noncurrent assets.

The following table summarizes the changes to these obligations, reported as asset retirement obligations (current and noncurrent liabilities) in our consolidated balance sheets, for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016, respectively:

| | Nuclear Plant Decommissioning | Mining Land Reclamation | Other | Total |
|---|---|---|---|---|
| ***Predecessor:*** | | | | |
| Liability at December 31, 2015 | $ 508 | $ 215 | $ 107 | $ 830 |
| Additions: | | | | |
| Accretion — January 1, 2016 through October 2, 2016 | 22 | 16 | 5 | 43 |
| Adjustment for new cost estimate | — | — | 1 | 1 |
| Incremental reclamation costs | — | 14 | 12 | 26 |
| Reductions: | | | | |
| Payments — January 1, 2016 through October 2, 2016 | — | (37) | (3) | (40) |
| Liability at October 2, 2016 | 530 | 208 | 122 | 860 |
| Less amounts due currently | — | (50) | (1) | (51) |
| Noncurrent liability at October 2, 2016 | $ 530 | $ 158 | $ 121 | $ 809 |
| ***Successor:*** | | | | |
| Fair value of liability established at October 3, 2016 | $ 1,192 | $ 374 | $ 152 | $ 1,718 |
| Additions: | | | | |
| Accretion — October 3, 2016 through December31, 2016 | 8 | 5 | 1 | 14 |
| Reductions: | | | | |
| Payments — October 3, 2016 through December31, 2016 | — | (4) | (2) | (6) |
| Liability at December 31, 2016 | 1,200 | 375 | 151 | 1,726 |
| Additions: | | | | |
| Accretion | 33 | 18 | 8 | 59 |
| Adjustment for change in estimates (a) | — | 81 | 44 | 125 |
| Incremental reclamation costs (b) | — | — | 62 | 62 |
| Reductions: | | | | |
| Payments | — | (36) | — | (36) |
| Liability at December 31, 2017 | 1,233 | 438 | 265 | 1,936 |
| Less amounts due currently | — | (93) | (6) | (99) |
| Noncurrent liability at December 31, 2017 | $ 1,233 | $ 345 | $ 259 | $ 1,837 |

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(a) Amounts primarily relate to the impacts of accelerating the ARO associated with the retirements of the Sandow 4, Sandow 5, Big Brown and Monticello plants (see Note 4 ).

(b) Amounts primarily relate to liabilities incurred as part of acquiring certain real property through the Alcoa contract settlement (see Note 4 ).

***Other Noncurrent Liabilities and Deferred Credits***

The balance of other noncurrent liabilities and deferred credits consists of the following:

| | December 31, | |
|---|---|---|
| | 2017 | 2016 |
| Unfavorable purchase and sales contracts | $ 36 | $ 46 |
| Other, including retirement and other employee benefits | 220 | 174 |
| Total other noncurrent liabilities and deferred credits | $ 256 | $ 220 |

*Unfavorable Purchase and Sales Contracts* — The amortization of unfavorable purchase and sales contracts totaled $10 million , $3 million , $18 million and $23 million for the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016 and the Predecessor period from January 1, 2016 through October 2, 2016 and the year ended December 31, 2015 , respectively. See Note 7 for intangible assets related to favorable purchase and sales contracts.

The estimated amortization of unfavorable purchase and sales contracts for each of the next five fiscal years is as follows:

| Year | Amount |
|---|---|
| 2018 | $ 11 |
| 2019 | $ 9 |
| 2020 | $ 9 |
| 2021 | $ 1 |
| 2022 | $ 3 |

***Fair Value of Debt***

| | December 31, 2017 | | December 31, 2016 | |
|---|---|---|---|---|
| Debt: | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Long-term debt under the Vistra Operations Credit Facilities (Note 12) | $ 4,323 | $ 4,334 | $ 4,515 | $ 4,552 |
| Other long-term debt, excluding capital lease obligations (Note 12) | 30 | 27 | 36 | 32 |
| Mandatorily redeemable subsidiary preferred stock (Note 12) | 70 | 70 | 70 | 70 |

We determine fair value in accordance with accounting standards as discussed in Note 15 , and at December 31, 2017 , our debt fair value represents Level 2 valuations. We obtain security pricing from an independent party who uses broker quotes and third-party pricing services to determine fair values. Where relevant, these prices are validated through subscription services such as Bloomberg.

***Supplemental Cash Flow Information***

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 | Period from January 1, 2016 through October 2, 2016 | Year Ended December 31, 2015 |
| Cash payments related to: | | | | |
| Interest paid (a) | $ 245 | $ 19 | $ 1,064 | $ 1,298 |
| Capitalized interest | (7) | (3) | (9) | (11) |
| Interest paid (net of capitalized interest) (a) | $ 238 | $ 16 | $ 1,055 | $ 1,287 |
| Income taxes | $ 63 | $ (2) | $ 22 | $ 29 |
| Reorganization items (b) | $ — | $ — | $ 104 | $ 224 |
| Noncash investing and financing activities: | | | | |
| Construction expenditures (c) | $ 12 | $ 1 | $ 53 | $ 75 |

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(a) Predecessor period includes amounts paid for adequate protection.
(b) Represents cash payments made by our Predecessor for legal and other consulting services, including amounts paid on behalf of third parties pursuant to contractual obligations approved by the Bankruptcy Court.
(c) Represents end-of-period accruals for ongoing construction projects.

The following table reconciles cash, cash equivalents and restricted cash reported in our statements of consolidated cash flows to the amounts reported in our consolidated balance sheets at December 31, 2017 and December 31, 2016:

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| Cash and cash equivalents | $ 1,487 | $ 843 |
| Restricted cash included in current assets | 59 | 95 |
| Restricted cash included in noncurrent assets | 500 | 650 |
| Total cash, cash equivalents and restricted cash | $ 2,046 | $ 1,588 |

## (b) SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF REGISTRANT

### VISTRA ENERGY CORP. (PARENT)
### SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF REGISTRANT
### CONDENSED STATEMENTS OF NET LOSS
### (Millions of Dollars)

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Selling, general and administrative expense | $ (47) | $ (7) |
| Loss from operations | (47) | (7) |
| Interest income | 4 | — |
| Impacts of Tax Receivable Agreement | 213 | (22) |
| Income (loss) before income taxes and equity earnings | 170 | (29) |
| Pretax equity in gains (losses) of consolidated subsidiaries | 80 | (204) |
| Income tax (expense) benefit | (504) | 70 |
| Net loss | $ (254) | $ (163) |

See Notes to the Condensed Financial Statements.

**VISTRA ENERGY CORP. (PARENT)**
**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF REGISTRANT**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(Millions of Dollars)**

| | Successor | |
|---|---|---|
| | Year Ended December 31, 2017 | Period from October 3, 2016 through December 31, 2016 |
| Cash flows — operating activities: | | |
| Net loss | $ (254) | $ (163) |
| Adjustments to reconcile net loss to cash provided by (used in) operating activities: | | |
| Pretax equity in (gains) losses of consolidated subsidiaries | (80) | 204 |
| Deferred income tax benefit (expense), net | 418 | (76) |
| Impacts of Tax Receivables Agreement | (213) | 22 |
| Other, net | 23 | 3 |
| Changes in operating assets and liabilities | (2) | (26) |
| Cash used in operating activities | (108) | (36) |
| Cash flows — financing activities: | | |
| Special dividend (Note 4) | — | (992) |
| Other, net | (1) | 1 |
| Cash used in financing activities | (1) | (991) |
| Cash flows — investing activities: | | |
| Dividend received from subsidiaries | 1,506 | 997 |
| Odessa Acquisition | (330) | — |
| Cash provided by financing activities | 1,176 | 997 |
| Net change in cash, cash equivalents and restricted cash | 1,067 | (30) |
| Cash, cash equivalents and restricted cash — beginning balance | 116 | 146 |
| Cash, cash equivalents and restricted cash — ending balance | $ 1,183 | $ 116 |

See Notes to the Condensed Financial Statements.

**VISTRA ENERGY CORP. (PARENT)**
**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF REGISTRANT**
**CONDENSED BALANCE SHEETS**
**(Millions of Dollars)**

| | December 31 | |
|---|---|---|
| | 2017 | 2016 |
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 1,124 | $ 26 |
| Restricted cash | 59 | 90 |
| Other current assets | 5 | 3 |
| Total current assets | 1,188 | 119 |
| Equity investments in consolidated subsidiaries | 4,927 | 6,067 |
| Accumulated deferred income taxes | 710 | 1,122 |
| Other noncurrent assets | 6 | 7 |
| Total assets | $ 6,831 | $ 7,315 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Trade accounts payable | $ 11 | $ — |
| Accrued taxes | 59 | 31 |
| Other current liabilities | 86 | 91 |
| Total current liabilities | 156 | 122 |
| Tax Receivable Agreement obligation | 333 | 596 |
| Total liabilities | 489 | 718 |
| Total shareholders' equity | 6,342 | 6,597 |
| Total liabilities and equity | $ 6,831 | $ 7,315 |

See Notes to the Condensed Financial Statements.

## NOTES TO CONDENSED FINANCIAL STATEMENTS

### 1. BASIS OF PRESENTATION

The accompanying unconsolidated condensed balance sheets, statements of net loss and cash flows present results of operations and cash flows of Vistra Energy Corp. (Parent). Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. GAAP have been omitted pursuant to the rules of the SEC. Because the unconsolidated condensed financial statements do not include all of the information and footnotes required by U.S. GAAP, they should be read in conjunction with the financial statements and related notes of Vistra Energy Corp. and Subsidiaries included in the 2017 Annual Report on Form 10-K. Vistra Energy Corp.'s subsidiaries have been accounted for under the equity method. All dollar amounts in the financial statements and tables in the notes are stated in millions of U.S. dollars unless otherwise indicated.

Vistra Energy Corp. (Parent) will file a consolidated U.S. federal income tax return. All consolidated tax expenses/benefits and deferred tax assets/liabilities are recorded at Vistra Energy Corp. (Parent).

***Adoption of New Accounting Standard*** — In November 2016, the FASB issued ASU 2016-18 *Statement of Cash Flows (Topic 230): Restricted Cash* . The ASU requires restricted cash to be included in the cash and cash equivalents and a reconciliation between the change in cash and cash equivalents and the amounts presented on the balance sheet. The ASU modifies the presentation of our condensed statements of cash flows, but does not have a material impact on our condensed statements of net loss and condensed balance sheets. We adopted the standard on January 1, 2018. However, the adoption of this ASU has been reflected on a retrospective basis in the financial statements of the Successor. For the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, our condensed statements of cash flows previously reflected sources of cash of $32 million and $36 million , respectively, reported as changes in restricted cash that are now reported in net change in cash, cash equivalents and restricted cash.

## 2. RESTRICTIONS ON SUBSIDIARIES

The agreement governing the Vistra Operations Credit Facilities (the Credit Facilities Agreement) generally restricts the ability of Vistra Operations Company LLC (Vistra Operations) to make distributions to any direct or indirect parent unless such distributions are expressly permitted thereunder. As of December 31, 2017, Vistra Operations can distribute approximately $1.0 billion to Vistra Energy Corp. (Parent) under the Credit Facilities Agreement without the consent of any party. The amount that can be distributed by Vistra Operations to Parent was partially reduced by distributions made by Vistra Operations to Parent during the year ended December 31, 2017 of approximately $1.1 billion . Additionally, Vistra Operations may make distributions to Vistra Energy Corp. (Parent) in amounts sufficient for Vistra Energy Corp. (Parent) to make any payments required under the Tax Receivables Agreement or the Tax Matters Agreement or, to the extent arising out of Vistra Energy Corp.'s (Parent) ownership or operation of Vistra Operations, to pay any taxes or general operating or corporate overhead expenses. As of December 31, 2017, the maximum amount of restricted net assets of Vistra Operations that may not be distributed to Parent totaled $3.9 billion .

## 3. GUARANTEES

As of December 31, 2017, there are no material outstanding guarantees at Vistra Energy Corp. (Parent).

## 4. DIVIDEND RESTRICTIONS

Under applicable law, Vistra Energy Corp. (Parent) is prohibited from paying any dividend to the extent that immediately following payment of such dividend there would be no statutory surplus or Vistra Energy Corp. (Parent) would be insolvent. On December 30, 2016, Vistra Energy Corp. (Parent) paid a special cash dividend in the aggregate amount of approximately $992 million to holders of record of its common stock on December 19, 2016.

Vistra Energy Corp. (Parent) received $1.506 billion and $997 million in dividends from its consolidated subsidiaries in the Successor period for the year ended December 31, 2017 and the period from October 3, 2016 through December 31, 2016, respectively.

## 5. SUPPLEMENTARY FINANCIAL INFORMATION

The following table reconciles cash, cash equivalents and restricted cash reported in our condensed statements of cash flows to the amounts reported in our condensed balance sheets at December 31, 2017 and December 31, 2016:

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| Cash and cash equivalents | $ 1,124 | $ 26 |
| Restricted cash | 59 | 90 |
| Total cash, cash equivalents and restricted cash | $ 1,183 | $ 116 |