MANAGEMENT'S DISCUSSION AND ANALYSIS
CRIUS ENERGY TRUST

March 8, 2018

This management's discussion and analysis ("**MD&A**") for Crius Energy Trust (the "**Trust**") dated March 8, 2018 has been prepared with all information available up to and including March 8, 2018. This MD&A should be read in conjunction with the Trust's audited consolidated financial statements and accompanying notes as at and for the years ended December 31, 2017 and 2016. The Trust's financial statements and other disclosure documents, including the Trust's Annual Information Form for the year ended December 31, 2017, dated March 8, 2018, are available on the System for Electronic Document Analysis and Retrieval ("**SEDAR**") under the Trust's issuer profile at www.sedar.com and on the Trust's website at www.criusenergytrust.ca. The trust units of the Trust ("**Units**") are traded on the Toronto Stock Exchange ("**TSX**") under the symbol "KWH.UN".

The Trust prepares its consolidated financial statements in accordance with International Financial Reporting Standards ("**IFRS**"), as issued by the International Accounting Standards Board ("**IASB**"). The consolidated financial statements of the Trust are presented in United States dollars, which is the functional currency of the Trust. All figures within this MD&A are presented in United States dollars unless otherwise indicated. Certain totals, subtotals and percentages may not reconcile due to rounding.

Certain information contained in this MD&A constitutes non-IFRS financial measures and/or forward-looking statements (as defined herein). Investors are cautioned to read the sections entitled *"Non-IFRS Financial Measures"* and *"Forward-Looking Statements"* at the end of this MD&A. Certain key terms and abbreviations used in this MD&A are defined in the section entitled *"Key Terms and Abbreviations"* below.

Overview of the Trust

The Trust is an unincorporated, open-ended limited purpose trust established under the laws of the Province of Ontario on September 7, 2012, for the purpose of providing investors with a distribution-producing investment. Following the completion of the initial public offering of the Trust in November 2012, the Trust held an approximate 26.8% indirect ownership interest in the operating subsidiaries of Crius Energy. In July 2015, the Trust acquired additional LLC Units (as defined herein) in exchange for consideration comprised of cash, financed by way of a prospectus offering of Units, resulting in an increase of the Trust's indirect ownership interest in the operating subsidiaries of Crius Energy from 26.8% to 43.1%. In June 2016, the Trust acquired the remaining LLC Units not already held, directly or indirectly, by the Trust in exchange for consideration comprised of Units and cash, financed by way of a prospectus offering of subscription receipts of the Trust, resulting in an increase in the Trust's indirect ownership interest in the operating subsidiaries of Crius Energy from 43.1% to 100% (the "**Remaining LLC Acquisition**").

Overview of Business

Crius Energy is a comprehensive energy solutions partner that provides innovative electricity, natural gas and solar products to residential and commercial customers through exclusive partnerships, direct-to-consumer, digital, and broker marketing channels. Our unique brands offer consumers a broad suite of energy products and services including fixed and variable contracts, renewable energy, and bundled products to support their energy needs beyond what is offered by their local utility. Company growth is achieved organically with customers acquired through our diversified marketing channels and through accretive acquisitions in the deregulated energy and solar industries, where there is a significant opportunity to participate in the consolidation of market participants. The Company currently sells energy products in 19 states and the District of Columbia in the United States with plans to continue expanding its geographic reach.

The Company's revenues are earned primarily from electricity and natural gas sales, and are recognized based on customer consumption. Seasonal variability of customer usage of electricity and natural gas may cause the Company's revenues and gross margins to fluctuate. In general, electricity consumption is highest during the summer months of July and August due to cooling demand and, to a lesser extent, during the winter months of January and February due to heating demand. Heating demand also influences natural gas consumption, which is typically highest between the months of November and March. The Company's revenues may also fluctuate based on retail rates charged to customers, customer growth and customer attrition. The Company also receives various other customer fees that are not tied to customer consumption.

In addition, the Company receives revenues from originating and installing solar systems, primarily based on the generating capacity of the solar systems it sells. Solar revenues are recognized upon certain milestones related to the installation of the solar systems.

The Company procures its electricity, natural gas and hedging requirements in various wholesale energy markets, including physical and financial markets, using both short-term and long-term contracts. For electricity and natural gas, the Company procures its wholesale energy requirements at various utility load zones for electricity and city gates for natural gas, based on the energy usage and geographic location of our customers. The Company manages its exposure to short-term and long-term movements in wholesale energy prices by hedging using derivative instruments. These derivative instruments are principally physical forward contracts and financial fixed-for-floating swaps, whereby the Company agrees to take physical delivery or cash settle the difference between the floating price and the fixed price on a notional quantity of electricity or natural gas for a specified timeframe, at a specified location. The Company remains subject to commodity risk for any volumetric differences between the actual quantities used by its customers and the forecasted quantities upon which such hedging instruments are based.

The Company's gross margin is primarily derived from the difference between the revenues received from its electricity and natural gas customers and the cost of sales paid to its energy and non-energy suppliers, together with its gross margin from the origination and installation of solar products. The Company also incurs selling expenses through a mixture of upfront and residual-based payments. All such costs are recognized as expenses in the period incurred, pursuant to the applicable contractual arrangements in place. In addition, the Company incurs general, administrative, financing and other expenses to operate its business.

Key Terms and Abbreviations

"**Adjusted EBITDA**" means EBITDA adjusted to exclude certain non-operating and non-cash items. See the section entitled *"Reconciliation of Net income (loss) to EBITDA and Adjusted EBITDA"* in this MD&A for a reconciliation of EBITDA and Adjusted EBITDA to Net income (loss) as calculated under IFRS, the most directly comparable measure in the Trust's consolidated financial statements. Adjusted EBITDA is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Adjusted Working Capital**" means current assets less current liabilities, excluding unrealized gains and losses on derivatives. See section entitled "*Adjusted Working Capital*" in this MD&A for a reconciliation of Adjusted Working Capital to the Trust's consolidated balance sheet as prepared under IFRS. Adjusted Working Capital is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Administrator**" means Crius Energy Administrator Inc., or such other party as may be appointed as administrator of the Trust from time to time.

"**Board**" means the board of directors of Crius Energy Administrator Inc., the administrator for and on behalf of the Trust.

"**Customer**" refers to an RCE (see definition of RCE below).

"**Deferred Trust Units**" or "**DTUs**" means the deferred trust units of the Trust issued pursuant to the DTUP (see definition of DTUP below).

"**Deferred Trust Unit Plan**" or "**DTUP**" means the deferred trust unit plan of the Trust adopted by the Trust on January 6, 2016 as amended, supplemented or restated from time to time.

"**Distributable Cash**" means the amount of cash flow available to the Trust to meet its distribution obligations. See the section entitled *"Distributable Cash and Distributions"* in this MD&A for a reconciliation of Distributable Cash to cash flows provided by (used in) operating activities as calculated under IFRS, the most directly comparable measure in the Trust's consolidated financial statements. Distributable Cash is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**EBITDA**" means earnings before interest, taxes, depreciation and amortization. EBITDA is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**kWh**" means kilowatt hour and is a measurement of volume of electricity.

"**LLC Units**" means the membership units of Crius Energy, LLC.

"**Maintenance Capital Expenditures**" consist of capital expenditures included within cash flows used in investing activities from the Consolidated Statement of Cash Flows, adjusted to exclude cash flows used in investing activities relating to acquisitions. Maintenance Capital Expenditures is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Macquarie Energy**" means Macquarie Energy LLC.

"**MMBtu**" means one million British Thermal Units and is a measurement of volume of natural gas.

"**MWh**" means Megawatt hour and is a measurement of volume of electricity.

"**MW**" means Megawatt and is a measurement of capacity of electricity.

"**Payout Ratio**" means the proportion of Distributable Cash paid out as distributions to Unitholders over a defined period, expressed as a percentage. See the section entitled *"Distributable Cash and Distributions"* in this MD&A for the calculation of Payout Ratio. Payout Ratio is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Phantom Unit Rights**" or "**PURs**" means cash-settled phantom unit rights granted under the PURP (see definition of PURP below.

"**Phantom Unit Rights Plan**" or "**PURP**" means the phantom unit rights plan of the Company adopted by the Company on November 13, 2012, as amended, supplemented or restated from time to time.

"**RCE**" or "**Residential Customer Equivalent**" is an industry-standard unit of measurement of energy consumption per annum equivalent to 10 MWh (or 10,000 kWh) in the case of the electricity and 100 MMBtu in the case of natural gas. The Company has estimated the number of RCEs in accordance with conventions adopted by the Company, in accordance with industry standards, based on information available regarding customers and their historical usage and are subject to adjustment based on updated available information.

"**SunEdison**" means SunEdison Inc.

"**Total Cash and Availability**" means the sum of cash and cash equivalents and any excess availability that is available to the Trust under its credit facilities. Total Cash and Availability is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Total Distributions**" means the total distributions made to Unitholders, including both distributions to Unitholders of the Trust as well as, for the applicable periods, distributions to non-controlling interest. Total Distributions is a non-IFRS financial measure. Refer to section entitled *"Non-IFRS Financial Measures"* at the end of this MD&A.

"**Unitholder**" means a holder of Units.

"**Units**" means the trust units of the Trust, which are listed for trading on the TSX under the symbol "KWH.UN".

"**USG&E Acquisition**" means the acquisition by the Trust of U.S. Gas & Electric, Inc. in July 2017.

"**USG&E**" means U.S. Gas & Electric, Inc.

"**Verengo**" means Verengo, Inc.

Unless the context indicates otherwise, references in this MD&A to "volume", "usage" and "consumption" refer to MWh in the case of electricity and MMBtu in the case of natural gas.

Throughout this MD&A, for purposes of convenience, references to (i) the "**Trust**", the "**Company**", "**Crius Energy**", "**we**" or "**our**" refer to Crius Energy Trust and its subsidiaries and (ii) "**Management**" refer to the management of the Trust and its subsidiaries.

2017 AND FOURTH QUARTER 2017 HIGHLIGHTS

Financial Highlights

2017

- Revenue of $875.9 million in 2017, representing an increase of 17.8% from $743.8 million in 2016.
- Gross margin of 21.0% of revenue, compared to 21.3% of revenue achieved in 2016.
- Adjusted EBITDA of $64.8 million during the year, a 6.6% increase from $60.8 million in 2016. During 2017, the deregulated energy business contributed $69.4 million in Adjusted EBITDA, and the solar business contributed negative $4.6 million to Adjusted EBITDA.
- Net income of $20.2 million in 2017, representing a decrease of 54.5% from $44.4 million in 2016.
- Distributable Cash of $45.0 million representing a Payout Ratio of 63.8% in 2017, compared to $38.9 million representing a Payout Ratio of 58.1% in 2016.
- Cash flows from operating activities of $13.2 million in 2017, representing a decrease of 67.8% from $41.0 million in 2016.

Fourth Quarter 2017

- Revenue of $248.5 million in the fourth quarter of 2017, representing an increase of 45.0% from $171.4 million in the fourth quarter of 2016.
- Gross margin of 22.1% of revenue for the fourth quarter, an increase from the gross margin of 21.9% of revenue achieved in the fourth quarter of 2016.
- Adjusted EBITDA of $18.0 million during the fourth quarter of 2017, representing an increase of 32.2% from $13.6 million in the fourth quarter of 2016. During the fourth quarter of 2017, the deregulated energy business contributed $20.8 million in Adjusted EBITDA, and the solar business contributed negative $2.8 million to Adjusted EBITDA.
- Net income of $36.0 million in the fourth quarter of 2017, representing an increase of 74.8% from $20.6 million in the fourth quarter of 2016.
- Distributable Cash of $13.0 million in the fourth quarter of 2017, compared to $9.2 million in the fourth quarter of 2016.
- Cash flows from operating activities of $14.8 million in the fourth quarter of 2017, representing a decrease of 2.6% from $15.2 million in the fourth quarter of 2016.

Operational Highlights

2017

- Net additions of 428,000 customers in 2017 with Crius Energy's customer count totaling 1,410,000 customers at the end of the year. The increase was driven by approximately 350,000 customers acquired through the USG&E Acquisition and through organic growth.
  - Added 1,020,000 customers during 2017, including gross adds of 670,000 customers added organically from sales and marketing channels, and 350,000 customers acquired through the USG&E Acquisition. This compares to 2016 gross adds of 390,000 customers added organically from sales and marketing channels and 75,000 customers acquired from Kona Energy.
  - Gross drops in 2017 were 592,000 customers, compared to gross drops of 302,000 customers in 2016. On a comparable period basis, increased customer drops were partly expected due to the expanded size of the portfolio as a result of both organic and acquisitive growth and partly due to elevated non-renewals of certain large commercial, municipal aggregation and default service auctions, which came up for renewal during the year, and were unable to be renewed at acceptable margins. On a percentage basis, customer attrition was 4.0% per month in 2017, compared to 2.6% per month in 2016.

Fourth Quarter 2017

- Net customer attrition of 36,000 customers in the fourth quarter of 2017 with Crius Energy's customer count totaling 1,410,000 customers at the end of the quarter. The decrease in customers during the fourth quarter of 2017 was primarily attributable to elevated attrition driven by approximately 50,000 municipal aggregation customers that came up for renewal, as previously communicated in prior quarterly reporting, that the Company was not able to renew at acceptable target margins.
  - Added 145,000 customers organically from sales and marketing channels, representing a decrease over the average in the prior four quarters of 154,000 customers.
  - Gross drops in the fourth quarter of 181,000 customers were higher than the average in the prior four quarters of 121,000 customers due to the above-mentioned non-renewal of approximately 50,000 municipal aggregation customers. Additionally, on a comparable period basis, the increased absolute number of customer drops is expected due to the expanded size of the portfolio as a result of the USG&E Acquisition. On a percentage basis, customer attrition was 4.0% per month for the fourth quarter of 2017, compared to 3.6% per month for the prior four quarters.

Growth and Corporate Highlights

2017

- Announced four 2% distribution increases during the year
  - As a result of the confidence that both Management and the Board have in the long-term outlook for the Company, strong operating cash flows and conservative Payout Ratio, the Board approved and implemented 2% distribution increases for each quarter during the year.
  - In total, the distribution per Unit was increased by 8.3% in 2017, following an increase of 8.3% in 2016, while the Company continued to maintain a conservative payout ratio.

- Successful completion of USG&E Acquisition
  - In July 2017, Crius Energy successfully completed the USG&E Acquisition which included a diverse portfolio of approximately 350,000 electricity and natural gas customers in Connecticut, Illinois, Kentucky, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and the District of Columbia.
  - As part of the USG&E Acquisition, the Trust issued 12,908,175 Units under a bought deal equity offering by way of a short form prospectus. The Trust also issued 3,847,870 Units to certain selling shareholders of USG&E, as partial consideration for the acquisition for a total equity issuance of 16,756,045 Units.
  - Management expects to achieve after-tax synergies to Distributable Cash of $41 million to $47 million over a three-year period based on annual run-rate after-tax cash synergies of $10 million to $12 million through organizational restructuring, a transition to the Company's technology platform, renegotiated credit facility pricing and trading terms

as well as one-time synergies of approximately $11 million in cash tax savings arising out of the ability to utilize net operating losses ("**NOLs**") of Verengo to offset current and future taxable income over the next two to three years.

- Announced a five-year extension to exclusive agreement with Comcast Corporation ("**Comcast**") to sell electricity and natural gas products under the Comcast Energy Rewards™ brand to Comcast customers
  - Comcast is expected to relaunch sales activities in the second quarter of 2018.

- Announced a five-year relationship with Comcast to offer Energy Rewards™ Integrated Energy Platform ("**IEP**") to additional third-party service providers
  - Five-year strategic agreement enables additional third-party service providers to efficiently offer their customers, among other products, electricity, natural gas and solar.
  - Crius Energy and Comcast will co-market the Energy Rewards™ IEP to potential third-party service providers. Crius Energy will continue to directly service all existing and future electricity and natural gas customer relationships.
  - Entered into a three-year strategic agreement with Rise Broadband, the largest U.S. fixed wireless internet and digital voice provider, to offer energy products to Rise Broadband's customers through the Energy Rewards™ IEP.
  - Entered into a three-year strategic agreement with CREDO Mobile, a mobile virtual network operator with approximately three million subscribers, to offer energy products to CREDO Mobile's customers through the Energy Rewards™ IEP.

- Received forgivable $8.0 million subordinated term loan from the Connecticut Department of Economic and Community Development
  - During the second half of 2016, the Company relocated to a renovated, 48,000 square foot space in Connecticut to accommodate current operating requirements and space for future growth.
  - The $8.0 million forgivable loan package was provided at an interest rate of 2.0% for a term of up to ten years to support the headquarter move.
  - The principal portion of the loan is deferred for the first four years and will be eligible for forgiveness credits as new jobs are created in the state.

Fourth Quarter 2017

- Announced further increase in distribution
  - In October 2017, the Board approved an additional increase of 2% to distributions paid on Units for the fourth quarter of 2017, representing an annualized increase of C$0.0161 per Unit and a total annualized distribution of C$0.8204 per Unit.

- Customer portfolio acquisition
  - In December 2017, the Company purchased the customer contracts and associated assets of approximately 18,000 residential electric customers in Illinois, Ohio, New Jersey and Pennsylvania from a California-based energy retailer for $4.3 million.

Highlights Subsequent to the End of 2017

- Announced an additional distribution increase
  - In January 2018, the Board approved an additional 2% increase to distributions paid on Units for the first quarter of 2018, representing an annualized increase of C$0.0164 per Unit and a total annualized distribution of C$0.8368 per Unit.
- Announced intention to implement a normal course issuer bid program (the "**Proposed NCIB Program**")
  - On January 30, 2018, the Trust announced its intention to implement the Proposed NCIB Program to purchase for cancellation, from time to time during the 12-month period of the Proposed NCIB Program, Units listed on the TSX in an aggregate amount of up to 10% of the "public float" of the Trust.
  - Any repurchases under the NCIB Program would be made in Canada through the facilities of the TSX and Crius would pay the prevailing market price for such Units at the time of purchase. The actual number of Units repurchased under the Proposed NCIB Program and the timing of such repurchases will be at Crius' discretion and shall be subject to the limitations set out in the TSX Company Manual.

- The Board believes that the underlying value of the Trust may not be reflected in the market price of the Units from time to time and that, accordingly, the purchase of Units will increase the proportionate interest in the Trust of, and be advantageous to, all remaining Unitholders.
- The commencement of the Proposed NCIB Program is subject to TSX approval.

- Executed a loan investment, providing potential for international expansion into the retail energy market of the United Kingdom
  - In January 2018, the Company advanced a short-term loan to a fast growing retail energy and smart meter installation business in the United Kingdom.
  - The loan is for £2.5 million, bears interest of 10% plus LIBOR, and has a one-year term and provides an option to acquire control within five years.

2017 DISCUSSION

The successful completion of the USG&E Acquisition was a highlight in 2017, and represented a transformative acquisition for the Company. The acquisition is expected to be highly accretive and, in addition to the Distributable Cash from the acquired business, is expected to provide after-tax synergies to Distributable Cash in the range of $41 million to $47 million over a three-year period. Crius Energy produced strong financial and operating performance in 2017, highlighted by healthy year-over-year growth of 43.6% in the customer base, due to both the USG&E Acquisition as well as continued strong organic growth, and 6.6% growth in Adjusted EBITDA. The increased performance and expected acquisition synergies highlight the Company's successful organic and acquisition growth strategy and scalable operating platform.

Overall revenues increased 17.8% in 2017 to $875.9 million from $743.8 million for the year ended December 31, 2016. The increase was largely driven by increased volumes due to higher average electricity customer numbers resulting from organic and acquisitive growth. Solar revenues increased from $2.3 million in 2016 to $11.2 million in 2017, driven by community solar revenues as well as the ramp-up in sales and marketing activities during the year as the Company integrated the Verengo and SunEdison assets. Solar revenues in 2017 were comprised of two components. The first component was revenue related to the origination and installation of solar systems of $6.2 million and the second component was $5.0 million in revenue related to the aggregation of community solar customers under a partnership with a leading developer of community solar projects.

Gross margin for 2017 was $184.0 million, up 16.1% from $158.5 million in 2016. The increase in gross margin was primarily a result of the incremental gross margin from the recently acquired USG&E business. As a percentage of total revenue, gross margin was 21.0% in 2017, in line with the 21.3% achieved in the previous year. The small decrease in gross margin as a percentage of revenue in the quarter is consistent with recent trends resulting from the increased mix of lower-margin commercial and municipal aggregation customers in the portfolio, partially offset by the addition of the higher-margin USG&E customer portfolio.

Adjusted EBITDA in 2017 was $64.8 million, a 6.6% increase compared to the $60.8 million reported in 2016, with the increase driven by the contribution from the recently acquired USG&E business, and partially offset by materially cooler-than-normal summer weather conditions in the third quarter of 2017 and the impact of the changing customer mix with a larger proportion of lower-margin commercial and municipal aggregation customers. During 2017, the deregulated energy business contributed $69.4 million in Adjusted EBITDA, and the solar business contributed negative $4.6 million to Adjusted EBITDA.

Net income in 2017 was $20.2 million, a decrease from $44.4 million in 2016, with the year-over-year reduction of $24.4 million impacted by the following significant drivers: an increase in depreciation and amortization of $18.8 million resulting from the USG&E Acquisition-related intangible assets, reduced changes in fair value of derivative instruments of $15.9 million, legal reserve and associated legal fees in 2017 of $17.5 million, increased finance costs of $5.0 million due to higher energy volumes as a result of the USG&E Acquisition, increased usage on the credit facility and interest on the new Term Loans entered into during 2017; partially offset by increased tax benefit of $24.4 million driven by the recognition of deferred tax assets relating to the Verengo NOLs and increased Adjusted EBITDA of $4.0 million.

Distributable Cash was $45.0 million in 2017, a 15.7% increase compared to $38.9 million reported in 2016. Total distributions paid in 2017 were $28.7 million, compared to $22.6 million in 2016, representing conservative year end payout ratios of 63.8% and 58.1%, respectively. The increase in Distributable Cash is primarily due to reduced capital expenditures compared to 2016 and the increase in Total Distributions is attributable to increases in the number of Units outstanding and increases in the amount distributed per Unit compared to 2016.

Cash flows provided by operating activities was $13.2 million in 2017, a decrease from $41.0 million in 2016, with the year-over-year reduction of $27.8 million primarily attributable to increased changes in net operating assets and liabilities of $17.0 million.

Management is pleased to report continued progress towards final resolution and settlement of the pending legal and regulatory matters for which the Company established a legal reserve in the first half of 2017, with the legal reserve remaining unchanged at $13.0 million as at December 31, 2017. The legal reserve together with associated legal fees of $4.5 million incurred during 2017 were excluded from Adjusted EBITDA and Distributable Cash. The associated legal fees incurred each quarter have exhibited a declining trend throughout the year, with $0.4 million incurred in the fourth quarter, as the matters near resolution.

Management has entered into agreements in principle to settle these litigation and regulatory matters and expects to execute such settlements within the next several months. With respect to certain class action litigation filed against the Company's Viridian brand relating to rate increases stemming from the 2013/2014 winter polar vortex weather event which caused significant increases to the underlying commodity wholesale prices, in February 2018, the Company filed with the United States District Court, District of Connecticut preliminary approval of the settlement agreement executed by all parties. The settlement agreement provides for a nationwide class settlement of all claims related to increased gas and electric rates which were at issue of the litigation.

As at December 31, 2017, Crius Energy had 1,410,000 customers, up from 982,000 at the end of 2016, representing net customer growth of 428,000 customers, or 43.6% year-over-year. The year-over-year increase in customers was driven by strong organic growth with gross customer adds of 670,000 and the acquisition of 350,000 customers from USG&E. Gross customer drops in 2017 totaled 592,000 customers compared to gross customer drops of 302,000 customers in 2016. On a comparable period basis, increased customer drops were partly expected due to the expanded size of the portfolio as a result of both organic and acquisitive growth and partly due to elevated non-renewals of certain large commercial, municipal aggregation and default service auctions, which came up for renewal during the year and were unable to be renewed at acceptable margins. On a percentage basis, customer drops were 4.0% per month in 2017, compared to 2.6% per month in 2016.

At December 31, 2017, the Trust had Total Cash and Availability of $49.4 million, consisting of $18.2 million of cash and cash equivalents and $31.2 million available under the Company's credit facilities. This compares to the Total Cash and Availability as at December 31, 2016 of $49.9 million, consisting of cash and cash equivalents of $10.9 million and $39.0 million available under the credit facility. The Trust continues to have a conservative balance sheet and sufficient resources to execute its growth strategy. The Company has $53.8 million in long-term debt, consisting of a $6.3 million subordinated, forgivable term loan with the Connecticut Department of Economic and Community Development at an annual interest rate of 2.0%, and $47.5 million in subordinated promissory notes ("**USG&E Sellers Note**") with certain shareholders of USG&E related to the USG&E Acquisition, which bear an annual interest rate of 9.5%.

During 2017, as a result of the confidence that both Management and the Board have in the long-term outlook for the Company, strong operating cash flows and conservative Payout Ratio, the Board approved and implemented 2% distribution increases for each quarter during the year, which resulted in an 8.3% increase in distributions per Unit, while continuing to maintain a conservative payout ratio.

OUTLOOK

Management is focused on delivering strong total Unitholder return by prioritizing investments in growth and the purchase of Units through the Proposed NCIB Program while remaining fully committed to our current level of distributions to Unitholders. Key to delivering strong total Unitholder return is continued growth in Distributable Cash, which is expected to be achieved through both margin growth and cost reduction. We expect to increase margin by growing our customer portfolio both through accretive acquisitions, and organically in our mass market and commercial segments, as well as focusing on increasing customer lifetime value through enhanced customer engagement, an expanded product suite, and portfolio optimization. We expect cost reduction to be achieved through the realization of our cost-synergy targets following our USG&E Acquisition and through continuing prudent cost management and economies of scale.

In the deregulated energy business, Management is focused on the acquisition and retention of higher margin mass market and commercial customers. In the commercial segment, we are focused on growth in the higher-margin small commercial segment and through expanding our portfolio of municipal aggregations. In the mass market segment, we are focused on expanding the USG&E direct-to-consumer sales channels, supporting the relaunch of Comcast, the launch of CREDO Mobile on the Energy Rewards™ IEP in the second quarter of 2018 and the expansion of Fairpoint Communications to additional markets following its acquisition by Consolidated Communications Holdings, Inc. in 2017, as well as continuing to add new exclusive partners to the Energy Rewards™ IEP. The Energy Rewards™ IEP strategy was designed to increase value from our strategic partnership

channel as it increases speed-to-market for new partners, reduces the cost for Crius Energy to on-board new partners and increases operational efficiency for serving customers going forward.

In addition to driving new customer growth, Management is focused on portfolio optimization, which is intended to increase margin and reduce attrition over the long-term as customers will receive differentiated products and service levels based on expected customer lifetime value. Management expects attrition to be elevated throughout 2018 as customers below internal customer lifetime value thresholds will be returned to the utility upon product expiration if we are unsuccessful at enrolling them on products that meet or exceed customer lifetime value thresholds.

In the solar business, we are focused on achieving profitability by the end of 2018 through focused sales and marketing activities in the California and Massachusetts markets, where we believe consumers have a strong customer value proposition in spite of potential pricing increases due to future tariffs on imported solar modules. In addition, Management expects to benefit from the installation capabilities of our Verengo business in California which enhances the overall margin to Crius, improves customer experience and reduces cancellation rates. Additionally, Management plans to leverage the deregulated energy business to increase solar sales opportunities and reduce solar customer acquisition costs.

Management continues to evaluate the expected impacts of the recent U.S. tax reform changes and, based on its preliminary assessment, believes that the reduction of the Federal corporate income tax rate from 35% to 21% benefits Distributable Cash of the Trust, however this benefit is expected to be mitigated by certain newly-introduced limitations on the deductibility of net interest expense as well as the reduced value of the NOLs acquired from Verengo as compared to our initial estimates.

Management continues to maintain focus on the integration of the USG&E business and on achieving the targeted synergies. We announced in our prior quarter MD&A that we expect to achieve run-rate annual after-tax synergies to Distributable Cash of $12 million to $14 million and one-time synergies of approximately $18 million in cash tax savings arising out of the ability to utilize NOLs of Verengo to offset current and future taxable income of USG&E, for a total three-year target synergy range of $55 million to $60 million. Based on ongoing integration efforts and our tracking and continued evaluation of target synergies, Management is on track to achieve the underlying pre-tax synergies to Distributable Cash with no changes from the initially estimated amounts, and no change to the expected timing of achieving run-rate synergies by 2018 year-end. However, based on our above-mentioned preliminary evaluation of the U.S. tax reform impacts, specifically the new limitations on interest deductibility and the reduced value of the Verengo NOLs, Management now expect the three-year after-tax synergy range to reduce to $41 million to $47 million.

In January 2018, the Board approved a 2% increase in distributions paid to Unitholders, following consecutive increases in each quarter since January 2016, delivering total return of over 25% by the end of January 2018. Going forward, Management and the Board have re-prioritized the use of cash flow, while remaining committed to the current distribution level. Excess cash flow will be used to fund investment in growth, for the purchase of Units through the Proposed NCIB Program (if and when implemented), and debt reduction when considered accretive to Unitholders. Management have instituted this capital allocation plan as we believe there is a significant opportunity to invest in the business and focus on growth of the customer portfolio.

Management continues to evaluate accretive acquisition opportunities including both asset and equity acquisitions. We believe the Company is well positioned to continue our acquisition strategy given our track-record of success integrating acquired businesses and conservative leverage levels.

As part of the Company's growth strategy, Management evaluates both domestic and international opportunities. Over the past several years, the Company has evaluated several international markets for business expansion. In January 2018, the Company identified an opportunity to enter the United Kingdom market by providing a short-term loan to a fast growing retail energy and smart meter installation business with an option to acquire control within five years. The loan is for £2.5 million, bears interest of 10% plus LIBOR, and has a one-year term. Management believes that this investment provides Crius Energy with a risk-averse opportunity to evaluate an international expansion opportunity by partnering with an existing management team with local experience in the United Kingdom.

Crius is well-positioned to leverage significant opportunities in both the deregulated energy and solar industries in 2018 and beyond. Our key priorities in 2018 are expected to increase Distributable Cash through margin growth and cost reduction. This strategy is expected to continue to bring value to investors through strong total Unitholder return supported by a commitment to current distribution levels.

Selected Consolidated Financial and Operational Data

The following selected historical financial information has been derived from the audited consolidated financial statements of the Trust as at and for the years ended December 31, 2017, 2016 and 2015 and the unaudited interim condensed consolidated financial statements of the Trust for the three months ended December 31, 2017 and 2016. The operating data has been prepared by Management based on the Company's records.

Statement of Comprehensive Income (Loss) Highlights
(in millions)

	Quarter ended December 31, 2017 (unaudited)	Quarter ended December 31, 2016 (unaudited)	Year ended December 31, 2017	Year ended December 31, 2016	Year ended December 31, 2015
Revenue	$248.5	$171.4	$875.9	$743.8	$686.3
Cost of sales	193.7	133.9	691.9	585.3	522.6
Gross margin	54.8	37.5	184.0	158.5	163.7
Expenses					
Selling expenses	11.2	6.6	34.4	28.8	38.9
General and administrative	26.0	17.3	102.3	76.2	72.2
Goodwill impairment	—	—	—	—	—
Unit-based compensation	0.1	0.7	5.9	4.9	4.4
Depreciation and amortization	12.0	9.4	58.3	39.5	49.1
Operating income (loss)	5.5	3.5	(16.9)	9.1	(0.9)
Other (expenses) income					
Finance costs	(5.2)	(1.9)	(15.3)	(10.3)	(9.0)
Distributions to non-controlling interest	—	—	—	(5.7)	(14.9)
Change in fair value of derivative instruments	32.2	21.3	30.2	46.1	14.9
Change in fair value of warrants	0.3	0.1	(0.4)	0.3	(1.1)
Change in fair value of non-controlling interest	—	—	—	6.7	(62.8)
Income (loss) before income taxes	32.8	23.0	(2.4)	46.2	(73.8)
(Benefit from) provision for income taxes	(3.2)	2.4	(22.6)	1.8	1.1
Net income (loss)	**$36.0**	**$20.6**	**$20.2**	**$44.4**	**$(74.9)**
EBITDA[1]	50.0	34.3	71.2	96.0	(15.7)
Adjusted EBITDA[1]	**$18.0**	**$13.6**	**$64.8**	**$60.8**	**$52.6**

Note:

(1) EBITDA and Adjusted EBITDA have limitations as analytical tools and should not be considered in isolation from, or as an alternative to, net income (loss) or other data prepared in accordance with IFRS. See the section entitled *"Non -IFRS Financial Measures"* in this MD&A. The following table is a reconciliation of net income to EBITDA and Adjusted EBITDA for the periods indicated.

Reconciliation of Net Income (Loss) to EBITDA and Adjusted EBITDA
(in millions)

	Quarter ended December 31, 2017 (unaudited)	Quarter ended December 31, 2016 (unaudited)	Year ended December 31, 2017	Year ended December 31, 2016	Year ended December 31, 2015
Net income (loss)	**$36.0**	**$20.6**	**$20.2**	**$44.4**	**$(74.9)**
Excluding the impacts of:					
Finance costs	5.2	1.9	15.3	10.3	9.0
(Benefit from) provision for income taxes	(3.2)	2.4	(22.6)	1.8	1.1
Depreciation and amortization	12.0	9.4	58.3	39.5	49.1
EBITDA	50.0	34.3	71.2	96.0	(15.7)
Excluding the impacts of:					
Goodwill impairment	—	—	—	—	—
Unit-based compensation	0.1	0.7	5.9	4.9	4.4
Distributions to non-controlling interest	—	—	—	5.7	14.9
Change in fair value of derivative instruments	(32.2)	(21.3)	(30.2)	(46.1)	(14.9)
Change in fair value of warrants	(0.3)	(0.1)	0.4	(0.3)	1.1
Change in fair value of non-controlling interest	—	—	—	(6.7)	62.8
Loss on sale of Viridian assets and related charges	—	—	—	7.3	—
Legal reserve and associated legal fees	0.4	—	17.5	—	—
Adjusted EBITDA	**$18.0**	**$13.6**	**$64.8**	**$60.8**	**$52.6**

Statement of Financial Position Highlights
(in millions)

	As at December 31, 2017	As at December 31, 2016	As at December 31, 2015
Current assets	$227.7	$126.3	$125.7
Total assets	567.0	299.3	302.6
Current liabilities	236.5	146.9	176.0
Long-term liabilities	81.8	12.8	162.4
Unitholders' equity	248.7	139.6	(35.8)

Statement of Cash Flows Highlights
(in millions)

	Quarter ended December 31, 2017 (unaudited)	Quarter ended December 31, 2016 (unaudited)	Year ended December 31, 2017	Year ended December 31, 2016	Year ended December 31, 2015
Cash flows provided by operating activities	$14.8	$15.2	$13.2	$41.0	$37.3
Cash flows used in investing activities	(6.6)	(1.5)	(102.5)	(20.5)	(20.4)
Cash flows (used in) provided by financing activities	(14.3)	(13.4)	96.5	(20.9)	(20.0)
Cash and cash equivalents at beginning of period	24.3	10.6	10.9	11.2	14.3
Cash and cash equivalents at end of period	18.2	10.9	18.2	10.9	11.2

Operational Highlights

	Quarter ended December 31, 2017 (unaudited)	Quarter ended December 31, 2016 (unaudited)	Year ended December 31, 2017	Year ended December 31, 2016	Year ended December 31, 2015
Electricity					
Volumes (MWh)	2,189,000	1,762,000	8,418,000	7,803,000	6,395,000
Revenue ($ million)	210.5	160.6	798.9	705.1	636.7
Gross margin ($ million)	38.8	32.3	148.0	138.4	140.5
Gross margin ($/MWh)	17.73	18.36	17.58	17.74	21.97
Gross margin as a % of revenue	18.4%	20.1%	18.5%	19.6%	22.1%
Natural gas					
Volumes (MMBtu)	5,120,000	1,880,000	9,783,000	5,817,000	5,959,000
Revenue ($ million)	33.3	9.1	58.7	28.2	41.5
Gross margin ($ million)	14.4	3.5	23.3	9.7	15.1
Gross margin ($/MMBtu)	2.82	1.85	2.38	1.66	2.54
Gross margin as a % of revenue	43.3%	38.1%	39.6%	34.2%	36.4%

Customer Aggregation

The following table summarizes the Company's gross additions and drops in electricity and natural gas customers from both organic growth and acquisition activity during the quarter ended December 31, 2017, and over the prior trailing four quarters.

Customer Aggregation
(in customers)[(1)]

	Opening Customer Count	Customer Adds	Customer Drops	Net Change	Closing Customer Count
Electricity	898,000	86,000	(65,000)	21,000	919,000
Natural Gas	64,000	5,000	(6,000)	(1,000)	63,000
Quarter ended December 31, 2016	**962,000**	**91,000**	**(71,000)**	**20,000**	**982,000**
Net Change % of Opening Customer Count				***2.1%***	
Electricity	919,000	153,000	(126,000)	27,000	946,000
Natural Gas	63,000	3,000	(9,000)	(6,000)	57,000
Quarter ended March 31, 2017	**982,000**	**156,000**	**(135,000)**	**21,000**	**1,003,000**
Net Change % of Opening Customer Count				***2.1%***	
Electricity	946,000	169,000	(141,000)	28,000	974,000
Natural Gas	57,000	3,000	(6,000)	(3,000)	54,000
Quarter ended June 30, 2017	**1,003,000**	**172,000**	**(147,000)**	**25,000**	**1,028,000**
Net Change % of Opening Customer Count				***2.5%***	
Electricity	974,000	396,000	(112,000)	284,000	1,258,000
Natural Gas	54,000	151,000	(17,000)	134,000	188,000
Quarter ended September 30, 2017	**1,028,000**	**547,000**	**(129,000)**	**418,000**	**1,446,000**
Net Change % of Opening Customer Count				***40.7%***	
Electricity	1,258,000	131,000	(167,000)	(36,000)	1,222,000
Natural Gas	188,000	14,000	(14,000)	0	188,000
Quarter ended December 31, 2017	**1,446,000**	**145,000**	**(181,000)**	**(36,000)**	**1,410,000**
Net Change % of Opening Customer Count				***(2.5)%***	

Note:

(1) Customer counts in the above table refer to RCEs or residential customer equivalents, an industry standard unit of measurement of consumption per annum equivalent to 10 MWh (or 10,000 kWh) in the case of the electricity and 100 MMBtu in the case of natural gas. We have estimated the number of RCEs in accordance with industry conventions based on information available regarding customers and their historical usage and are subject to adjustment based on updated available information. Customer adds and customer drops do not always reflect a customer's service commencement date or service end date due to time lags following the customer's enrolment date and termination request date.

(2) Customer Adds in the quarter ended September 30, 2017 include 350,000 RCEs acquired from USG&E in July 2017, comprising 216,000 electricity customers and 134,000 natural gas customers.

Solar System Sales and Installations

The following table summarizes the Company's solar systems sold and solar systems installed over the three months ended December 31, 2017, as well as the prior quarters ended September 30, 2017, June 30, 2017 and March 31, 2017. The sales and installations relate only to sales and installations under the current integrated solar business model, and exclude any installations pursuant to the prior legacy reseller business model.

Solar Systems Sold and Installed[1]
(by number and in MW of generating capacity)

	Systems	MW
Quarter ended March 31, 2017		
Gross Sales	271	1.8
Installations	15	0.1
Quarter ended June 30, 2017		
Gross Sales	258	1.8
Installations	35	0.2
Quarter ended September 30, 2017		
Gross Sales	179	1.4
Installations	30	0.2
Quarter ended December 31, 2017		
Gross Sales	131	0.9
Installations	71	0.5

Note:

(1) Gross sales of solar systems in the above table represent gross sales only and we expect a certain portion of these sales to be cancelled by the customer prior to installation. Additionally, there is a time lag between gross sales and the installation of the solar systems, which may vary based on numerous factors.

(2) The above table does not include solar system installations related to the Verengo solar business.

Summary of Quarterly Results
Quarterly Results (unaudited)
(in millions)

	Quarter ended December 31, 2017	Quarter ended September 30, 2017	Quarter ended June 30, 2017	Quarter ended March 31, 2017	Quarter ended December 31, 2016	Quarter ended September 30, 2016	Quarter ended June 30, 2016	Quarter ended March 31, 2016
Revenue	$248.5	$269.9	$180.2	$177.4	$171.4	$222.6	$169.0	$180.8
Cost of sales	193.7	214.9	143.0	140.3	133.9	174.8	135.9	140.6
Gross margin	54.8	55.0	37.2	37.1	37.5	47.8	33.1	40.2
Expenses								
Selling expenses	11.2	12.2	6.1	4.9	6.6	8.4	6.6	7.2
General and administrative	26.0	24.8	24.9	26.7	17.3	26.1	12.9	20.0
Unit-based compensation	0.1	1.0	2.1	2.6	0.7	1.5	1.1	1.6
Depreciation and amortization	12.0	14.3	14.3	17.7	9.4	10.6	10.1	9.4
Operating income (loss)	5.5	2.7	(10.2)	(14.8)	3.5	1.2	2.4	2.0
Other (expenses) income								
Finance costs	(5.2)	(5.5)	(2.4)	(2.3)	(1.9)	(3.1)	(2.6)	(2.8)
Distributions to non-controlling interest	—	—	—	—	—	—	(2.2)	(3.5)
Change in fair value of derivative instruments	32.2	7.1	(0.8)	(8.3)	21.3	(5.3)	37.4	(7.2)
Change in fair value of warrants	0.3	0.4	(0.4)	(0.6)	0.1	—	—	0.1
Change in fair value of non-controlling interest	—	—	—	—	—	—	7.7	(1.0)
Income (loss) before income taxes	32.8	4.7	(13.8)	(26.0)	23.0	(7.2)	42.7	(12.4)
(Benefit from) provision for income taxes	(3.2)	(20.3)	0.8	0.2	2.4	(1.6)	2.4	(1.3)
Net income (loss)	**$36.0**	**$25.0**	**$(14.6)**	**$(26.2)**	**$20.6**	**$(5.6)**	**$40.3**	**$(11.1)**

Reconciliation of Net Income (Loss) to EBITDA and Adjusted EBITDA

Net income (loss)	**$36.0**	**$25.0**	**$(14.6)**	**$(26.2)**	**$20.6**	**$(5.6)**	**$40.3**	**$(11.1)**
Excluding the impacts of:								
Finance costs	5.2	5.5	2.4	2.3	1.9	3.1	2.6	2.8
(Benefit from) provision for income taxes	(3.2)	(20.3)	0.8	0.2	2.4	(1.6)	2.4	(1.3)
Depreciation and amortization	12.0	14.3	14.3	17.7	9.4	10.6	10.1	9.4
EBITDA	50.0	24.5	2.9	(6.0)	34.3	6.5	55.4	(0.2)
Excluding the impacts of:								
Unit-based compensation	0.1	1.0	2.1	2.6	0.7	1.5	1.1	1.6
Distributions to non-controlling interest	—	—	—	—	—	—	2.2	3.5
Change in fair value of derivative instruments	(32.2)	(7.1)	0.8	8.3	(21.3)	5.3	(37.4)	7.2
Change in fair value of warrants	(0.3)	(0.4)	0.4	0.6	(0.1)	—	—	(0.1)
Change in fair value of non-controlling interest	—	—	—	—	—	—	(7.7)	1.0
Loss on sale of Viridian assets and related charges	—	—	—	—	—	7.3	—	—
Legal reserve and associated legal fees	0.4	0.3	7.9	9.0	—	—	—	—
Adjusted EBITDA	**$18.0**	**$18.3**	**$14.1**	**$14.5**	**$13.6**	**$20.6**	**$13.6**	**$13.0**

Distributable Cash and Payout Ratio

Cash flows provided by (used in) operating activities	**$14.8**	**$5.3**	**$1.3**	**$(8.2)**	**$15.2**	**$19.2**	**$7.1**	**$(0.6)**
Changes in operating assets and liabilities	(4.4)	(13.4)	(5.7)	(14.2)	2.2	(1.2)	(6.7)	(14.9)
Cash flows from operating activities excluding changes in operating assets and liabilities	19.2	18.7	7.0	6.0	13.0	20.4	13.8	14.3
Finance costs included in financing activities	(5.0)	(5.3)	(2.7)	(2.3)	(2.3)	(3.1)	(2.5)	(2.5)
Maintenance capital expenditures	(1.6)	(0.5)	(0.8)	(0.9)	(1.2)	(6.1)	(2.0)	(1.4)
Unit based compensation	—	—	—	(4.1)	(0.3)	(0.6)	—	(0.6)
Legal reserve and associated legal fees	0.4	0.3	7.9	9.0	—	—	—	—
Distributable Cash	**$13.0**	**$13.2**	**$11.4**	**$7.7**	**$9.2**	**$10.6**	**$9.3**	**$9.8**
Distributions to non-controlling interest	—	—	—	—	—	—	3.4	3.6
Distributions to Unitholders	8.9	8.2	5.8	5.8	5.7	5.6	2.2	2.1
Total Distributions	**$8.9**	**$8.2**	**$5.8**	**$5.8**	**$5.7**	**$5.6**	**$5.6**	**$5.7**
Payout Ratio	**68.5%**	**62.1%**	**50.9%**	**75.3%**	**62.0%**	**52.8%**	**60.2%**	**58.2%**

Discussion of Operations
For the years ended December 31, 2017 and December 31, 2016

Revenue

For the year ended December 31, 2017, revenue was $875.9 million, representing an increase of 17.8% from $743.8 million for the year ended December 31, 2016.

Electricity

Electricity revenue for the year ended December 31, 2017 was $798.9 million, representing an increase of 13.3% from $705.1 million for the year ended December 31, 2016, as a result of a 7.9% increase in volume and a 5.0% higher average retail rate per unit. Electricity volumes for the year ended December 31, 2017 were 8,418,000 MWh representing an increase of 7.9% from 7,803,000 MWh for the year ended December 31, 2016, with the increase primarily due to higher average customer numbers associated with the USG&E Acquisition.

Natural Gas

Natural gas revenue for the year ended December 31, 2017 was $58.7 million, representing an increase of 107.7% from $28.2 million for the year ended December 31, 2016, as a result of a 68.2% increase in volume and a 23.5% increase in average retail rate per unit. Natural gas volumes for the year ended December 31, 2017 were 9,783,000 MMBtu, representing an increase of 68.2% from 5,817,000 MMBtu for the year ended December 31, 2016, with the increase primarily resulting from higher average customer numbers associated with the USG&E Acquisition.

Solar Revenue

Solar revenue for the year ended December 31, 2017 was $11.2 million, representing an increase of $8.9 million from revenues of $2.3 million for the year ended December 31, 2016. Solar revenues consisted of two components. Firstly, revenues related to the origination and installation of the solar systems for the year ended December 31, 2017 were $6.2 million, compared to $2.3 million in the prior comparable period driven by the ramp-up in sales and marketing activities during the year as the Company integrated the Verengo and SunEdison assets. Secondly, solar revenues included $5.0 million in community solar revenues from an initiative launched for the aggregation of community solar customers. The initiative, which was entered into during the second quarter of 2017, offers a direct-to-consumer program that allows customers to purchase solar energy from community based solar installations backed by five-year power purchase agreements. Crius Energy receives a customer acquisition fee which is recognized as revenue based upon customer acquisition activity, which is primarily undertaken prior to the development of the solar farms, with the balance of the revenue being recognized over the life of the agreements, based on customer acquisition required to replace attrition. The initial agreement is related to solar farms in the Texas market with nameplate capacity of approximately 63 MW developed in 2017, which equates to approximately 32,000 community solar customers, of which approximately two-thirds were signed up in the second quarter of 2017 and the remaining customers were signed up in the third quarter of 2017.

Fee Revenue

Fee revenue, consisting of various fees received from customers and sign-up fees and other monthly fees received from independent contractors in the network marketing channel, for the year ended December 31, 2017 was $7.2 million, representing a decrease of 11.0% from $8.1 million for the year ended December 31, 2016, which was attributable to elimination of fees from Viridian independent contractors following the sale of certain Viridian assets in July 2016 partially offset by increased customer fee revenues.

Gross Margin

For the year ended December 31, 2017, gross margin was $184.0 million, representing an increase of 16.1% from $158.5 million for the year ended December 31, 2016. Gross margin for the year ended December 31, 2017 was 21.0% of total revenue, compared to 21.3% of total revenue for the year ended December 31, 2016. Gross margin benefited from increased average customer numbers due to the addition of the customer portfolio acquired from USG&E at the beginning of the third quarter of 2017.

Electricity

Electricity gross margin for the year ended December 31, 2017 was $148.0 million, representing an increase of 6.9% from $138.4 million for the year ended December 31, 2016. For the year ended December 31, 2017, electricity gross margin per unit was $17.58/MWh and electricity gross margin was 18.5% of electricity revenues, compared to $17.74/MWh and 19.6%, respectively, for the year ended December 31, 2016. Gross margins in the current year were higher than the prior year comparable period, primarily due to the higher average customer numbers due to the addition of the customer portfolio acquired from USG&E at the beginning of the third quarter of 2017 but partially offset by the adverse impact from the cooler-than-normal summer weather conditions, which were 24% lower than the prior comparable period as measured by Cooling Degree Days ("**CDDs**"), resulting in materially lower electricity usage per customer. Lower period-over-period gross margin per unit and gross margin as a percentage of revenue is consistent with recent trends resulting from the increased mix of lower-margin commercial and municipal aggregation customers in the portfolio, but offset by the addition of the higher-margin USG&E portfolio.

Natural Gas

Natural gas gross margin for the year ended December 31, 2017 was $23.3 million, representing an increase of 140.5% from $9.7 million for the year ended December 31, 2016. For the year ended December 31, 2017, natural gas gross margin per unit was $2.38/MMBtu and natural gas gross margin was 39.6% of natural gas revenues representing an increase from $1.66/MMBtu and 34.2%, respectively, for the year ended December 31, 2016. The increase in gross margin and gross margins per unit in the year were primarily attributable to the acquisition of the USG&E customer portfolio at the beginning of the third quarter of 2017.

Other

Gross margin for the year ended December 31, 2017 included solar gross margin of $5.6 million and various fees received from customers of $7.2 million. Gross margin for the year ended December 31, 2016, included solar gross margin of $2.3 million and revenues from independent contractors in the network marketing channel and various fees received from customers of $8.1 million, with the period-over-period changes due to the reasons noted above.

Selling Expenses

Selling expenses consist of commissions due to our various sales channels including independent contractors, commercial and residential brokers, telemarketing and door-to-door vendors, partners in our strategic partnerships, employees both for customer consumption and enrolling new electricity, natural gas and solar customers, and vendors used in the Company's direct mail and other direct marketing campaigns. Selling expenses are expensed in the period during which they are earned by the independent contractors, strategic partners, employees or vendors, as applicable.

Commissions earned are comprised of upfront commissions, which are primarily based on the successful enrollment of customers, and residual commissions, which are primarily based on customer consumption and receipt of customer payments. The commission structures utilized are summarized below:

- Commissions due to independent contractors in our direct marketing channels primarily comprise upfront commissions, based on successful customer enrollments, and may be subject to a partial or full repayment of such commission for customers who terminate their service within certain time frames, or paid under hourly contracts. Selling costs also include costs from various vendors used in direct mail and other direct marketing campaigns.

- Commissions due to brokers in our commercial broker channel are primarily residual commissions, which are based on energy usage over a customer's term of enrollment.

- Commissions due for customers acquired through our strategic partnerships are calculated primarily based on upfront commissions calculated per customer enrolled, and may be subject to a partial or full repayment of such commission for customers who terminate their service within certain time frames and a residual-based commission based on revenue or energy usage over a customer's term of enrollment.

- Commissions due to independent contractors for customers acquired through network marketing (prior to the sale of certain Viridian assets in July 2016) were calculated according to a multi-level compensation plan designed to reward independent contractors for building successful marketing networks. Under the compensation plan, independent contractors are eligible to earn upfront and residual commissions, cash bonuses and promotional pay based on several factors, including, but not limited to, customer enrollment and energy usage.

- Commissions due to employees and independent contractors based on customer enrolments and/or the size and pricing of the solar systems sold.

For the year ended December 31, 2017, selling expenses were $34.4 million, representing an increase of 19.5% from $28.8 million for the year ended December 31, 2016. Selling expenses for the year ended December 31, 2017 amounted to 3.9% of revenue and were consistent with the 3.9% of revenue incurred for the year ended December 31, 2016. These expenses consist of:

(a) Upfront electricity and natural gas customer acquisition costs for the year ended December 31, 2017 of $13.8 million (amounting to $21 per customer acquired), representing an increase from $8.3 million for the year ended December 31, 2016 (amounting to $21 per customer acquired), with the higher costs in 2017 being impacted by the increased additions as a result of the USG&E Acquisition. The upfront selling costs per customer were driven higher following the USG&E Acquisition, but offset by the large number of additions related to municipal aggregations and default service auctions in the period, which have minimal upfront selling costs.

(b) Residual-based electricity and natural gas commissions for the year ended December 31, 2017 of $17.7 million (amounting to 2.1% of revenues), representing an increase from $17.2 million for the year ended December 31, 2016 (amounting to 2.3% of revenues). Residual-based commissions were higher in 2017, primarily due to the addition of residual-based commissions associated with the USG&E Acquisition at the beginning of the third quarter of 2017, partially offset by the increase in the acquisition accounting related to the broker commission liabilities in the year ended December 31, 2017.

(c) Solar selling costs for the year ended December 31, 2017 of $2.9 million, compared to $3.3 million for the year ended December 31, 2016.

General and Administrative Expenses

General and administrative expenses for the year ended December 31, 2017 were $102.3 million compared to $76.2 million for the year ended December 31, 2016, as set forth in the table below.

Excluding the impact of the legal reserve and associated legal fees and the loss on sale of Viridian assets and related charges, which were excluded from Adjusted EBITDA, general and administrative expenses would have been $84.8 million for the year ended December 31, 2017, compared to $68.9 million for the prior comparable period, with the net increase of $15.9 million being primarily attributable to the addition of the cost-base of USG&E for the second half of 2017, as well as $2.3 million in non-recurring transaction and integration costs related to the USG&E Acquisition, which closed in July 2017.

General and Administrative Expenses
(in $ millions and % of revenue)

	Year ended December 31, 2017		Year ended December 31, 2016	
	$	%	$	%
POR fees / bad debt	$9.0	1.0%	$6.6	0.9%
Processing costs	5.5	0.6%	4.7	0.6%
Human resources	30.4	3.5%	27.0	3.6%
Gross receipts taxes and other taxes	9.2	1.1%	7.9	1.1%
Professional and consultant fees	5.6	0.6%	3.1	0.4%
Legal and regulatory	2.8	0.3%	4.2	0.6%
Solar operating expenses	7.3	0.8%	3.7	0.5%
Other costs	15.0	1.7%	11.7	1.6%
Loss on sale of Viridian assets and related charges	—	—%	7.3	1.0%
Legal reserve and associated legal fees	17.5	2.0%	—	—%
Total	**$102.3**	**11.7%**	**$76.2**	**10.2%**

General and administrative expenses incurred during the year ended December 31, 2017 were made up of the following categories:

(a) POR fees/bad debt represent fees paid to the local distribution companies ("**LDCs**") pursuant to Purchase of Receivables ("**POR**") programs, under which the LDCs assume credit risk associated with customer non-payment and bad debt costs incurred in markets where the Company does not operate under a POR program, which exposes the Company to customer credit risk. The POR fees/bad debt expense for the year ended December 31, 2017 was $9.0 million, representing 1.0% of revenue, compared to $6.6 million for the year ended December 31, 2016, representing 0.9% of revenue for that period, with the increase primarily due to the USG&E Acquisition at the beginning of the third quarter of 2017.

(b) Processing costs for the year ended December 31, 2017 of $5.5 million include various data processing and information technology costs incurred to service our customers and salesforce. This figure compares to $4.7 million for the year ended December 31, 2016, with the increase primarily due to the USG&E Acquisition.

(c) Human resource costs for the year ended December 31, 2017 of $30.4 million, consist of costs incurred in relation to the Company's employee base, temporary staff and independent contractors compared to costs in the prior comparable period in 2016 of $27.0 million, with the increase primarily due to the USG&E Acquisition.

(d) Gross receipts taxes and other taxes for the year ended December 31, 2017 of $9.2 million, representing 1.1% of revenue, represent operational taxes in various states and jurisdictions and are primarily driven by revenue. This compares to the $7.9 million, representing 1.1% of revenue, incurred in the prior comparable period in 2016, with the increase primarily attributable to higher revenues including increased revenues following the USG&E Acquisition.

(e) Professional and consultant fees for the year ended December 31, 2017 of $5.6 million represent audit, tax, investor relations, share registry, valuation, due diligence, internal controls consulting and other fees and compares to $3.1 million in the prior comparable period in 2016, with current period impacted by $1.3 million in transaction and integration costs related to the USG&E Acquisition.

(f) Legal and regulatory costs for the year ended December 31, 2017 of $2.8 million represent external legal fees and compares to $4.2 million in the prior comparable period in 2016. The current period was impacted by $1.0 million in transaction costs related to the USG&E Acquisition, while the prior comparable period was impacted by acquisition related legal fees and fees associated with the Viridian divestiture.

(g) Solar operating expenses for the year ended December 31, 2017 of $7.3 million represent costs associated with the operation of the solar business and compare to $3.7 million in the prior comparable period in 2016, with the increase due to the prior period costs only including solar operating expenses for the third and fourth quarter as prior to the acquisition of the SunEdison residential solar business and the Verengo acquisition, there were no solar operating expenses in the fee-based legacy reseller solar business.

(h) Other costs for the year ended December 31, 2017 of $15.0 million represent the balance of corporate, operational and marketing related expenses incurred to operate the business. These costs compare to $11.7 million in the prior comparable period in 2016, with the current period being impacted by the USG&E Acquisition at the beginning of the third quarter of 2017.

(i) As a result of the sale of the Viridian assets in July 2016 to Viridian International, the Company recognized a loss on sale and related charges of $7.3 million for the year ended December 31, 2016. These represent non-recurring charges including the difference between the consideration received from Viridian International and the net book value of the intangible assets related to the Viridian sales channel that were established in the initial public offering of the Trust in November 2012, as well as a charge to fully reserve for the amounts owed to Crius Energy by Viridian International under the transaction agreements. These charges were excluded from Adjusted EBITDA.

(j) Legal reserve and associated legal fees for the year ended December 31, 2017 amounted to $17.5 million, consisting of the legal reserve established by the Company of $13.0 million, and associated legal fees of $4.5 million for the year ended December 31, 2017, for certain pending litigation and regulatory matters relating to sales and marketing practices. Management does not expect the disposition of these matters to have a material adverse effect on the Company's results of operations or financial condition and will seek to resolve these matters in the manner Management believes to be in the best interests of Unitholders. This legal reserve, together with associated legal fees incurred were excluded from Adjusted EBITDA and Distributable Cash.

Unit-Based Compensation

The unit-based compensation charge relates to the cumulative net issuance of PURs to Management and other parties under the PURP, as well as of DTUs to Board members under the DTUP. For the year ended December 31, 2017, unit-based compensation expense amounted to $5.9 million, representing an increase from $4.9 million for the year ended December 31, 2016. The expense reflects the fair value of the unit-based compensation based on the market price of the Units at the end of the period and the applicable vesting period.

Depreciation and Amortization

Depreciation and amortization relate to the property and equipment and intangibles used in the Company's operations. Depreciation and amortization for the year ended December 31, 2017 was $58.3 million, representing an increase from $39.5 million for the year ended December 31, 2016. The increase is primarily attributable to the amortization of newly-established intangible assets related to the USG&E Acquisition in the second half of 2017.

Finance Costs

Finance costs for the year ended December 31, 2017 were $15.3 million, representing an increase from $10.3 million for the year ended December 31, 2016. Finance costs are incurred pursuant to the Supplier Agreements (as defined herein) as well as under the Term Loans. Refer to the discussion in the section entitled *"Liquidity and Capital Resources"* in this MD&A, for a detailed description of the Supplier Agreements and the Term Loans. The higher finance fees for the year ended December 31, 2017 were attributable to the higher energy volumes as a result of the USG&E Acquisition at the beginning of the third quarter of 2017, increased usage on the credit facility, partially to fund the cash portion of the USG&E Acquisition and interest on the Term Loans which were entered into during 2017.

Distributions to Non-Controlling Interest

Due to certain provisions relating to redemption rights for the non-controlling interest in change of control circumstances that existed in the Trust's governance documents prior to the completion of the Remaining LLC Acquisition in June 2016, the non-controlling interest was classified as a long-term liability on the consolidated statement of financial position. Accordingly, prior to June 2016, distributions paid by Crius Energy, LLC to the non-controlling interest were included in the profit and loss under this caption. Distributions to non-controlling interest were $5.7 million for the year ended December 31, 2016. However, following June 2016 there are no longer distributions to non-controlling interest due to the elimination of the non-controlling interest ownership of the LLC Units as a result of the Remaining LLC Acquisition in June 2016, which resulted in the Trust owning a 100% interest in the operating subsidiaries of Crius Energy.

Change in Fair Value of Derivative Instruments

The change in fair value of derivative instruments consists of changes in unrealized gains or losses on derivatives, which represent the estimated amount that the Trust would need to pay or receive to dispose of the remaining notional commodity or currency positions in the market if the derivative contracts to which the Company are party were to be terminated at the respective period end (see the section entitled *"Financial Instruments and Risk Management"* in this MD&A).

For the year ended December 31, 2017, the changes in unrealized gains or losses associated with derivative contracts were net gains of $30.2 million compared to net gains of $46.1 million for the year ended December 31, 2016. The net gains and losses in the periods were primarily the result of increases and decreases in forward energy prices relative to our forward hedge positions.

Change in Fair Value of Derivative Instruments
(in millions)

	Year ended December 31, 2017	Year ended December 31, 2016
Forward electricity positions	$33.2	$39.3
Forward natural gas positions	(3.3)	8.2
Weather derivative positions	0.1	(0.5)
Forward currency positions	0.2	(0.9)
Change in fair value of derivative instruments	**$30.2**	**$46.1**

These gains and losses represent non-cash gains and losses associated with mark-to-market movements on forward hedge positions that are outstanding at period end. These hedges are put in place to hedge either the fixed price exposure of customers on fixed price contracts, the expected short-term exposure of variable priced customers, or the impacts of currency movements on the Trust's distributions, thereby minimizing the impact of these unrealized mark-to-market gains and losses.

Change in Fair Value of Warrants

The change in fair value of warrant liability for the year ended December 31, 2017 represented a loss of $0.4 million compared to a gain of $0.3 million for the year ended December 31, 2016. These gains and losses represents the mark-to-market valuation of the 750,000 Unit purchase warrants ("**Warrants**") issued to Macquarie Energy in connection with the Crius Supplier Agreement (as defined in the section entitled *"Liquidity and Capital Resources"* in this MD&A). The valuation of the Warrants is based on an option valuation model, and accordingly the non-cash gains and losses are the result of changes in the Unit price, volatility, yield, time to maturity and the risk-free rate over the period.

Change in Fair Value of Non-Controlling Interest

In June 2016, the Trust acquired all the remaining LLC Units not already owned by the Trust, following which the Trust no longer has a non-controlling interest liability relating to the non-controlling members of Crius Energy, LLC. Accordingly, the Trust no longer has gains and losses representing the mark-to-market valuation of such non-controlling interest liability. However, due to certain provisions relating to redemption rights for the non-controlling interest in change of control circumstances that existed in the Trust's governance documents prior to the Remaining LLC Acquisition completed in June 2016, the non-controlling interest was classified as a long-term liability on the statement of financial position. Accordingly, this non-controlling interest is measured at fair value at the end of each period with the gain or loss being recorded in the profit and loss. The fair value of the non-controlling interest was measured principally based on the trading price of Units on the TSX, with an adjustment for certain profit interest units of the Company that was calculated using an option pricing model. The change in fair value of non-controlling interest was a gain of $6.7 million for the year ended December 31, 2016 and was primarily the result of changes in the trading price of Units, during the reporting period.

(Benefit from) Provision for Income Taxes

For the years ended December 31, 2017 and December 31, 2016, the Trust recorded a benefit from income taxes of $22.6 million and a provision for income taxes of $1.8 million respectively. The Trust was in a pre-tax loss position for the year, and was in a net loss position for the same period after adjusting for permanent differences. The Trust's (benefit from) provision for income taxes relates to the Trust's U.S. subsidiaries. Deferred tax assets are recognized to the extent that the Trust believes that the likelihood of recognition is probable. The benefit from income taxes during the year was impacted by (i) the recognition of deferred tax assets meeting the recognition criterion during the period primarily related to NOLs of Verengo that are expected to be utilized against current and future taxable income as a result of the USG&E Acquisition subject to the applicable limitations and rules in the Internal Revenue Code; and (ii) the re-measurement of deferred tax assets during the period to reflect the reduced corporate income tax rate pursuant to the passing of the U.S. *Tax Cuts and Jobs Act*.

Net Income

For the year ended December 31, 2017, net income was $20.2 million, compared to net income of $44.4 million for the year ended December 31, 2016, with the changes being attributable to the factors noted above. Net income is impacted by numerous non-cash items, some being a result of the structure of the Trust and its subsidiaries as well as the industry in which they operate. Accordingly, Management believes the additional non-IFRS financial measures of Adjusted EBITDA and Distributable Cash are useful metrics to be considered together with net income (loss) for evaluating the Trust's financial and operating performance, as they are measures that Management uses internally to assess performance.

Liquidity and Capital Resources

The Trust expects to have sufficient liquidity to fund its planned operations for the foreseeable future. The following are the primary sources of funding for future expenditures that are expected by Management to be available: (i) internally generated cash flow from operations; (ii) existing cash and working capital; (iii) borrowing capacity under the Supplier Agreements (detailed below); and (iv) existing external debt financing. Additionally, Management may seek to raise capital through further debt financing or through the issuance of additional Units.

Supplier Agreements

Following the acquisitions of USG&E and Big Sky Gas in the third quarter of 2017, Crius Energy has three separate supplier agreements (collectively referred to as "**Supplier Agreements**") in place, which are detailed below.

Crius Supplier Agreement

The supplier agreement in place between Crius Energy and Macquarie Energy ("**Crius Supplier Agreement**") provides for the exclusive supply of wholesale energy needs and hedging requirements for the Crius Energy business (excluding the newly acquired USG&E and Big Sky Gas operations) for a term ending in January 2019. Under the Crius Supplier Agreement, Macquarie Energy assumes the responsibility for meeting all the credit and collateral requirements with each Independent System Operator. Further, the Company's customers as well as the LDCs serving the Company's customers are directed to remit all customer payments into a designated restricted bank account (the "**Lockbox**"), and the funds in that account are used to pay Macquarie Energy for energy supplied and other fees and interest due under the Crius Supplier Agreement. The trade payables are secured by funds pledged in the Lockbox, accounts receivable, natural gas inventory and all other Company assets.

Macquarie Energy extends trade credit to buy wholesale energy supply, with all amounts due being payable in the month following the delivery of the energy. The credit extended under the Crius Supplier Agreement is limited to an overall exposure limit of $250.0 million subject to certain standard financial covenants, and limited to a calculated credit base based on restricted cash in the Lockbox, billed and unbilled receivables, natural gas inventory, forward value of customers and certain other items. The Company incurs a volumetric fee based on the wholesale energy delivered, which is included as finance costs in the profit and loss. Effective February 1, 2016, the Company entered into an amended supplier agreement with Macquarie Energy, whereby the volumetric fees are temporarily reduced until the Company reaches an agreed upon savings. Upon reaching the targeted savings, the volumetric fees will revert to their previous rate.

The arrangement includes a working capital facility with a sub-limit of $60.0 million under which letters of credit and cash advances can be made based on the calculated credit base. Such letters of credit and cash advances under this line are subject to an annual interest rate of 5.5% plus LIBOR (1.57% as at December 31, 2017), with an incremental interest rate of 1.25% applied to borrowings above a certain threshold.

Under the Crius Supplier Agreement, the Company and its operating subsidiaries are permitted to make monthly distributions provided that (i) no event of default, termination event or potential event of default has occurred, (ii) Macquarie Energy has been paid in full for all amounts owing under all then outstanding monthly invoices, (iii) Macquarie Energy has not received notice that any amount owed to any party is then currently past due, and (iv) the requested distribution would not result in a breach of any covenant under the agreement.

As at December 31, 2017, the Company has $55.0 million outstanding under its credit facility and has letters of credit issued totaling $9.3 million with Macquarie Energy, compared to $9.5 million outstanding under its credit facility and letters of credit issued totaling $11.5 million as at December 31, 2016. The credit facility balance was impacted by the funding of the cash portion of the purchase price of the USG&E Acquisition, which closed in July 2017. As at December 31, 2017, the Company was in compliance with all of its covenants under the Crius Supplier Agreement.

USG&E Supplier Agreement

As a result of the USG&E Acquisition, the Company has an additional supplier agreement with Macquarie Energy (the "**USG&E Supplier Agreement**").

The terms of the USG&E Supplier Agreement are similar to the Crius Supplier Agreement, with the following key differences. The overall facility size is limited to $85.0 million, with conditions for increases to $150.0 million with Macquarie Energy's approval. The facility provides for cash advances pursuant to a revolving line of credit (the "**Revolver**"), with a sub-limit of $35.0 million (the "**Revolver Sub-limit**"), that can be used for working capital and other purposes. The facility also provides for the deferral of accounts payable to Macquarie Energy of up to $10.0 million for 30 days and storage loans for natural gas inventory. The interest rate on the Revolver, standby letters of credit, deferred payables and storage loans is 5.5% plus the 30-day LIBOR (1.57% as at December 31, 2017), per annum, payable monthly and there is a commitment fee of 0.5%, per annum, payable quarterly, on the average daily unused amount of the Revolver Sub-limit.

As at December 31, 2017, the Company has letters of credit issued totaling $8.2 million and no cash advances or storage loans drawn under the Revolver or accounts payable deferrals. As at December 31, 2017, the Company was in compliance with all of its covenants under the USG&E Supplier Agreement.

Big Sky Supplier Agreement

As a result of its acquisition of Big Sky Gas, the Company has a supplier agreement (the "**Vantage Supplier Agreement**") with Vantage Commodities Financial Services II.

The current terms of the Vantage Supplier Agreement include, among other things: (1) facility size up to $2.5 million; (2) maturity date of October 2018; (3) deferred supply sub-limit of $1.5 million; (4) interest rate on the utilization fee, revolving facility and deferred supply of 5.5% plus the 30-day LIBOR (1.57% as at December 31, 2017), per annum, payable monthly and (5) commitment fee of 1.0%, per annum. The Vantage Supplier Agreement provides for advances under a revolving facility that can be used for working capital and other purposes.

As at December 31, 2017, there were no letters of credit and cash advances of $0.6 million drawn under the Vantage Supplier Agreement. As at December 31, 2017, the Company was in compliance with all of its covenants under the Vantage Supplier Agreement.

Term Loans

The Company has two term loans, which are held by the Connecticut Department of Economic and Community Development ("**CT DECD**") and certain USG&E selling shareholders (together referred to as "**Term Loans**").

In January 2017, the CT DECD advanced a term loan to the Company in the amount of $8.0 million, for a term of up to 10 years, at an annual interest rate of 2.0% (the "**CT DECD Term Loan**"). Repayment of the CT DECD Term Loan principal is deferred for the first four years of the loan term. The Term Loan contains a provision for potential debt forgiveness or early redemption based on the Company achieving certain headcount targets agreed upon with the CT DECD.

In July 2017, as part of the USG&E Acquisition, certain selling shareholders advanced a subordinated promissory note to the Company in the amount of $47.5 million at an annual interest rate of 9.5%. The note has an eight year term that matures in July 2025, is non-amortizing with accrued interest being payable quarterly over the term. The promissory note is secured by the assets of USG&E, but is subordinated to the security interest of Macquarie Energy under the Supplier Agreements. The USG&E Sellers Note is subject to adjustment for post-closing working capital adjustments as well as a portion of any indemnity claims under the acquisition agreements.

Total Cash and Availability

As of December 31, 2017, the Trust had Total Cash and Availability of $49.4 million consisting of cash and cash equivalents of $18.2 million and $31.2 million of availability under the credit facilities. This compares to the Total Cash and Availability as at December 31, 2016 of $49.9 million, consisting of cash and cash equivalents of $10.9 million and $39.0 million of availability under the credit facility.

Cash Flow provided by (used in) Operations

Cash flow provided by operations for the year ended December 31, 2017 was $13.2 million, which compared to $41.0 million for the year ended December 31, 2016, with the year-over-year reduction primarily attributable to higher net outflows of $37.6 million for changes in operating assets and liabilities compared to net outflows of $20.6 million in the prior year. Cash flow provided by operations excluding changes in operating assets and liabilities was $50.8 million for the year ended December 31, 2017, compared to $61.6 million for the year ended December 31, 2016, with the decrease being primarily attributable to the $17.5 million legal reserve and associated legal fees for certain pending litigation and regulatory matters relating to certain sales and marketing practices.

Cash flow provided by operations for the three month period ended December 31, 2017 was $14.8 million, which compared $15.2 million for the three month period ended December 31, 2016. Cash flows provided by operations excluding changes in operating assets and liabilities was $19.2 million for the three month period ended December 31, 2017, compared to $13.0 million for the three month period ended December 31, 2016 as a result of the increased cash flows following the USG&E Acquisition.

Changes in operating assets and liabilities primarily arise due to the time lag associated with the cash conversion cycle or the period between the time the Company pays for wholesale energy and the time it receives payments from our customers for the energy it sells, which is also impacted by the business' growth and seasonality. The Supplier Agreements in place are borrowing base facilities and, as such, provide access to cash needed to fund changes in operating assets and liabilities associated with the build-up of customer accounts receivables and trade payables subject to a borrowing base.

Distributable Cash and Distributions

Distributable Cash for the year ended December 31, 2017 was $45.0 million and Total Distributions paid for the year were $28.7 million, which represented a Payout Ratio of 63.8% of Distributable Cash. This compares to Distributable Cash of $38.9 million, Total Distributions of $22.6 million and a Payout Ratio of 58.1% for the year ended December 31, 2016. The year-over-year increase in Distributable Cash was primarily attributable to lower capital expenditures partially offset by higher financing costs resulting from (i) increased energy volumes following the USG&E Acquisition at the beginning of the third quarter of 2017, (ii) increased usage of the credit facility, partially to fund the cash portion of the USG&E Acquisition and (iii) interest on the Term Loans which were entered into during 2017. The year-over-year increase in the Payout Ratio was a result of higher distributions due to the increasing distribution rate and the increase in Units issued and outstanding related to Units issued for the partial funding of the USG&E Acquisition. Distributable Cash excludes $17.5 million in costs relating to the legal reserve and associated legal fees relating to the pending litigation and regulatory matters. Including these costs would have resulted in Distributable Cash of $27.5 million for the year ended December 31, 2017, representing a Payout Ratio of 104.4%.

Distributable Cash for the three month period ended December 31, 2017 was $13.0 million and Total Distributions paid for the period were $8.9 million, which represented a Payout Ratio of 68.5% of Distributable Cash. This compares to Distributable Cash of $9.2 million, Total Distributions of $5.7 million and a Payout Ratio of 62.0% for the three month period ended December 31, 2016.

The following table provides a reconciliation of Cash flows provided by operating activities to Distributable Cash and shows the Payout Ratio of Total Distributions as a percentage of Distributable Cash.

Distributable Cash and Payout Ratio (unaudited)
(in millions)

	Quarter Ended December 31, 2017	Quarter Ended December 31, 2016	Year ended December 31, 2017	Year ended December 31, 2016
Cash flows provided by operating activities	**$14.8**	**$15.2**	**$13.2**	**$41.0**
Changes in operating assets and liabilities	(4.4)	2.2	(37.6)	(20.6)
Cash flows from operating activities excluding changes in operating assets and liabilities	19.2	13.0	50.8	61.6
Finance costs - included in financing activities	(5.0)	(2.3)	(15.3)	(10.5)
Maintenance Capital Expenditures	(1.6)	(1.2)	(3.8)	(10.7)
Unit-based compensation payments	—	(0.3)	(4.2)	(1.5)
Legal reserve and associated legal fees	0.4	—	17.5	—
Distributable Cash	**$13.0**	**$9.2**	**$45.0**	**$38.9**
Distributions to non-controlling interest	—	—	—	6.9
Distributions to Unitholders	8.9	5.7	28.7	15.7
Total Distributions	**$8.9**	**$5.7**	**$28.7**	**$22.6**
Payout Ratio	**68.5%**	**62.0%**	**63.8%**	**58.1%**

Working Capital

The table below shows the calculation of working capital and Adjusted Working Capital based on the Trust's consolidated balance sheet as prepared under IFRS:

Adjusted Working Capital
(in millions)

	As at December 31, 2017	As at December 31, 2016
Current assets	$227.7	$126.3
Current liabilities	236.5	146.9
Working capital	**$(8.8)**	**$(20.6)**
Adjusted for the impact of:		
Other current financial assets	(19.4)	(2.1)
Other current financial liabilities	0.0	9.3
Adjusted Working Capital	**$(28.2)**	**$(13.4)**

As of December 31, 2017, the Trust had a working capital balance of negative $8.8 million, compared to negative $20.6 million in the prior comparable period, with the improvement driven by an increase of $26.6 million in net mark-to-market assets related to derivative instruments over the period primarily as a result of movements in wholesale energy market prices.

Working capital includes the impact of Other current financial assets and liabilities, which relate to certain mark-to-market positions on derivative instruments outstanding at the end of the reporting period. These gains and losses represent non-cash gains and losses associated with mark-to-market movements on forward hedge positions that are outstanding at period end. These hedges are put in place to hedge either the fixed price exposure of customers on fixed price contracts, the expected short-term exposure of variable priced customers, or the impacts of currency movements on the Trust's distributions, thereby minimizing the impact of these unrealized mark-to-market gains and losses. By way of further clarification, a mark-to-market asset or liability is realized over time together with an equal and offsetting underlying customer position, with the end result being there is no net impact from a liquidity or cashflow perspective. For this reason, Management calculate Adjusted Working Capital, defined as current assets less current liabilities, excluding unrealized gains and losses on derivatives, as as alternative non-IFRS measure to assess the working capital position of the Company from a liquidity and cash flow perspective.

Adjusted Working Capital as of December 31, 2017 was negative $28.2 million compared to negative $13.4 million as at December 31, 2016.

The negative working capital and Adjusted Working Capital as at December 31, 2017 is impacted by the $13.0 million legal reserve established relating to certain pending litigation and regulatory matters relating to sales and marketing practices as well as the elevated usage on the credit facility of $55.6 million, which was used to partially fund the cash portion of the USG&E Acquisition. The credit facility is a revolver facility and the outstanding balance is not due for repayment during the term of the facility provided the Company remains in compliance with its terms and covenants. As as December 31, 2017, the working capital and Adjusted Working Capital, excluding the credit facility balance outstanding, is positive.

Contractual Obligations

In the normal course of business, the Company is obligated to make future payments under various non-cancellable contracts and other commitments. As at December 31, 2017, the payments due by period are set forth in the following table and the Company expects to be able to fund such amounts from cash flows provided by operations during the corresponding periods, as well as cash and availability under the Company's credit facilities:

Contractual Obligations (in millions)	**Contractual cash flow**	**Less than 1 year**	**1 to 5 years**	**More than 5 years**
Trade and other payables	$199.3	$182.8	$16.5	$—
Operating leases	19.0	2.5	10.8	5.6
Financing leases	2.2	1.1	1.1	—
Credit facility	55.6	55.6	—	—
Distribution payable	3.0	3.0	—	—
Other non-current liabilities	10.3	—	9.5	0.8
Term loan payable	56.5	0.2	4.5	51.9
	$345.9	**$245.2**	**$42.4**	**$58.3**

Outstanding Unit Data

As at December 31, 2017, the Trust had the following securities outstanding: (i) 56,944,417 Units; (ii) 750,000 Warrants which were issued to Macquarie Energy in February 2014; and (iii) 77,433 Deferred Trust Units (which were issued under the Deferred Trust Unit Plan of the Trust to non-executive directors of the Administrator as a component of their annual compensation). The 750,000 Warrants outstanding are comprised of (i) 687,500 Warrants that have vested, and (ii) 62,500 Warrants that were unvested as at December 31, 2017, but vested on February 7, 2018. Such Warrants have a strike price of C$6.23 per Unit over a five-year term ending on February 6, 2019.

Subsequent to the end of 2017, the Trust issued 85,650 Units in connection with the acquisition of certain residential solar assets from Verengo. Following the issuance of these Units, the Trust had 57,030,067 Units outstanding.

Financial Instruments and Risk Management

Overview

The Trust's operations are affected by a number of underlying risks, both internal and external to the Trust. The Trust's financial position, results of operations and cash distributions are directly impacted by these factors. A description of the operational and business risks facing the Trust is set forth in the Trust's Annual Information Form for the year ended December 31, 2017, dated March 8, 2018, which is available on SEDAR under the issuer profile of the Trust at www.sedar.com and on the Trust's website at www.criusenergytrust.ca. The Trust's activities expose it to a variety of financial risks that arise as a result of its operating, investing, and financing activities, including:

- market risk, including commodity risk, interest rate risk and foreign currency risk;
- credit risk, including customer credit risk and counterparty credit risk;
- liquidity risk; and
- supplier risk.

This part of the MD&A sets out information about the Trust's exposure to each of the above-noted risks, the Trust's objectives, policies and processes for measuring and managing such risks, and the Trust's management of capital. Further quantitative disclosures are included throughout the Trust's consolidated financial statements.

Market Risk

Market risk is the potential loss that may be incurred as a result of changes in the market or fair value of a particular instrument or commodity. Components of market risk to which the Trust is exposed are discussed below.

Commodity risk

The Company has entered into contracts with customers to provide electricity or natural gas at variable or fixed prices. Fixed-price contracts expose the Company to changes in market prices of electricity and natural gas, as the Company is obligated to purchase electricity and natural gas at floating wholesale market prices for delivery to its customers. The Trust is, therefore, exposed to market risks associated with commodity prices and market volatility where estimated customer requirements do not match actual customer requirements. Management actively monitors these positions on a daily basis in accordance with the Company's risk management policy (the "**Risk Management Policy**"). The Risk Management Policy prohibits speculative positions and sets out a variety of hedging limits, most importantly a target of maintaining a 100% hedged position, within certain tolerance bands, at all times for fixed-price contracts exposure in our electricity and natural gas portfolios. The Trust's exposure to commodity risk is affected by a number of factors, including the accuracy of estimation of customer commodity requirements, commodity prices, and market volatility and liquidity.

Electricity and natural gas derivatives

To reduce its exposure to short-term and long-term movements in commodity prices, arising from the procurement of electricity and natural gas at floating prices, the Company uses derivative instruments. These derivative instruments are principally physical forward contracts and fixed-for-floating swaps, whereby the Company agrees with a counterparty, through the Supplier Agreement, to take physical delivery or cash settle the difference between the floating price and the fixed price on a notional quantity of electricity or natural gas, for a specified timeframe at a specified location. The cash flow from these instruments is expected to be effective in offsetting the Company's price exposure and serves to fix the Company's wholesale cost of electricity or natural gas to be delivered to the customer. The Company remains subject to commodity risk for any volumetric differences between the actual quantities used by customers and the forecasted quantities upon which the commodity hedging instruments are based.

Realized swap settlements under derivative instruments are included in cost of sales in the Trust's consolidated statements of comprehensive income. Unrealized gains or losses resulting from changes in the fair value of the derivative instruments, generally referred to as mark-to-market gains or losses, have been recognized as the change in fair value on derivative instruments in the consolidated statements of comprehensive income.

The fair value of derivative financial instruments is the estimated amount that the Company would pay or receive to dispose of these derivative instruments in the market in the unlikely event that the Company was required to dispose of its derivative instruments. The Company has estimated the value of its derivative instruments using market-based, forward wholesale price curves wherever available.

As at December 31, 2017, the Company had electricity and natural gas derivative instruments outstanding with the following terms:

	Notional Volume	Total Remaining Volume	Maturity Date (months)	Fixed Price ($)	Fair Value ($ millions)	Notional Value ($ millions)
Fixed-for-floating electricity swaps	20 – 100 MW	8,742,669 MWh	1 – 48	$21.04 to $80.20	$17.6	$363.5
Fixed-for-floating natural gas swaps	(155,000) – 155,000 MMBtu	7,342,857 MMBtu	1 – 27	$2.01 to $3.64	($1.2)	$21.2
Physical electric forward contracts	1 – 30 MW	1,530,176 MWh	1 – 52	$17.56 to $50.20	$1.0	$46.0
Physical natural gas forward contracts	(15,500) – 196,416 MMBtu	3,504,908 MMBtu	1 – 15	$0.25 to $8.10	($0.9)	$4.2
Fixed-for-floating natural gas basis swaps	(1,071) – 1,071 MMBtu	60,000 MMBtu	1 – 3	$(0.49) to $0.00	($0.1)	$—
Heat rate forward contracts	2 – 3 MW	7,168 MWh	1 – 6	$27.71 to $30.19	$—	$0.2
Electricity capacity contracts	4 – 183 MW	1,359,800 MWh	1 – 16	$0.36 to $9.52	($0.8)	$5.5
Financial transmission rights	0 – 31 MW	1,035,771 MWh	1 – 5	$(3.81) to $5.77	($0.3)	$1.4

The fair value of electricity and natural gas financial instruments is significantly influenced by the variability of forward commodity prices. Periodic changes in forward prices could cause significant changes in the mark-to-market valuation of these financial instruments. For example, assuming that all other variables remain constant, a market move of +/-10% would result in an increase / (decrease) in net income and total comprehensive income of $39.4 million but would not impact Adjusted EBITDA or Distributable Cash.

Interest rate risk

The Trust is exposed to interest rate risk on certain advances within the Company's supplier agreements. As at December 31, 2017, the Trust had cash advances and letters of credit outstanding of $55.6 million and $17.5 million respectively under the Supplier Agreements and, therefore, is exposed to interest rate risk. The Trust does not currently believe that it is exposed to material interest rate risk and the Trust's current exposure to interest rate risk does not economically warrant the use of derivative instruments to manage this risk. In the year ended December 31, 2017, the impact of a 1.0% increase (decrease) in the interest rate on these balances would not have had a material impact on finance costs in the statement of comprehensive income.

Foreign currency risk

The Trust is exposed to currency rate risk as the Company's business operations are conducted in United States dollars, whereas distributions to Unitholders are denominated in Canadian dollars and the Units are traded on the TSX in Canadian dollars.

Currency derivatives

The Trust's policy is to mitigate its exposure to currency rate movements by entering into currency derivative products, including foreign currency options whereby the Company agrees with a counterparty to have the right to swap the floating price for a fixed price on a notional quantity of currency at or over a specified timeframe. The Trust maintains a rolling hedging program for this foreign currency exposure of at least 12 forward months, which may be extended on a quarterly basis.

As at December 31, 2017, the Trust was hedged for its currency exposure to December 31, 2019 with a foreign exchange collar with a floor of C$1.30 per US$1.00 and a cap exchange rate of C$1.40 per US$1.00, based on approximately the current level of future distributions, including the increased level of distributions following the recent equity issuances as part of the USG&E Acquisition.

As at December 31, 2017, the Company had foreign currency derivatives outstanding with the following terms:

	Notional Value (millions)	Maturity Date (months)	Fixed Price	Fair Value (millions)
Foreign exchange options	US$72.0 C$93.6	1-24	C$1.30 and C$1.40 per US$1	US$3.6

As of the date of this MD&A, the Trust extended the term of the hedge cover and is now hedged for its currency exposure to December 31, 2020 with a foreign exchange collar with a floor of C$1.25 per US$1.00 and a cap exchange rate of C$1.40 per US$1.00, based on approximately the current level of future distributions.

Realized settlements under derivative instruments are included in the relevant section of the consolidated statements of comprehensive income (loss) or consolidated balance sheet. Unrealized gains or losses resulting from changes in the fair value of the derivatives, generally referred to as mark-to-market gains or losses, have been recognized as the change in fair value on derivative instruments in the consolidated statements of comprehensive income.

The fair value of derivative financial instruments is the estimated amount that the Company would pay or receive to dispose of these derivative instruments in the market in the unlikely event that the Company was required to dispose of its derivative instruments. The Company has estimated the value of derivative instruments using market-based prices and option valuation methods.

Period to period changes in forward currency prices could cause significant changes in the mark-to-market valuation of these hedge contracts. For example, assuming that all other variables remain constant, a market move of +/-10% would result in increase (decrease) in net income and total comprehensive income of $6.8 million and $(2.5) million, respectively, but would not impact Adjusted EBITDA or Distributable Cash.

Credit risk

Credit risk is the risk that one party to a financial instrument fails to discharge an obligation and causes financial loss to another party. The Trust is exposed to credit risk in two specific areas: customer credit risk and counterparty credit risk.

Customer credit risk

In certain markets in which the Company serves electricity and natural gas customers, LDCs provide collection services and assume the risk of any bad debts owing from the Company's customers for a fee, which is referred to as a POR fee. Management believes that the risk of the LDCs failing to deliver payment to the Company is minimal; however, there is no assurance that the LDCs that provide these services will continue to do so in the future.

In certain other markets in which the Company operates, the Company is exposed directly to customer credit risk. As a result, credit review and other processes have been implemented to perform credit evaluations of customers and manage customer defaults. Customer credit risk exposure represents the risk related to the Company's accounts receivable from certain markets. If a significant number of customers in these markets were to default on their payments, it could have an adverse effect on the operations and cash flows of the Company.

As at December 31, 2017, the customer credit risk exposure was $8.8 million, compared to $7.8 million for the year ended December 31, 2016 and the accounts receivable aging for these markets are as follows:

	Total	Current	30-59 days	Over 60 days
Accounts receivable	$8.8	$7.1	$0.6	$1.1

Counterparty credit risk

Counterparty credit risk represents the loss that the Trust would incur if a counterparty fails to perform its contractual obligations. This risk would manifest itself in the Trust replacing the contracted commodities or currencies at prevailing market rates, thus impacting the related financial results. Counterparty risk relating to the Company's derivative financial assets with its counterparties for commodity, currency and other derivatives amounted to $19.4 million as at December 31, 2017 compared to $2.1 million for the year ended December 31, 2016. The Trust is also exposed to counterparty credit risk on certain loans and other receivables totaling $7.1 million, owed to it by Viridian International. These amounts are fully reserved for based on the Company's understanding and assessment of Viridian International's ability to pay. The failure of a counterparty to meet its contracted obligations could have a material adverse effect on the operations and cash flows of the Trust.

Liquidity risk

Liquidity risk is the potential inability to meet financial obligations as they fall due. The Trust manages this risk by monitoring near-term and long-term cash flow forecasts to ensure adequate and efficient use of cash resources and credit facilities.

The table in the section entitled *"Contractual Obligations"* of this MD&A outlines the contractual maturities of the Trust's financial liabilities as at December 31, 2017.

Supplier risk

The Company purchases the energy it delivers to its customers primarily through contracts entered into with Macquarie Energy. This exposes the Company to supplier risk, as its ability to continue to deliver energy to its customers depends upon the ongoing operations of this supplier and its fulfillment of its contractual obligations.

Off-Balance Sheet Arrangements

Pursuant to its Supplier Agreements, the Company has issued letters of credit as at December 31, 2017 and December 31, 2016 totaling $17.5 million and $11.5 million respectively, to various counterparties, principally LDCs.

Pursuant to separate arrangements with various insurance companies, the Company has issued surety bonds to various counterparties, including U.S. states, regulatory bodies and LDCs in return for a fee and/or meeting certain collateral posting requirements. Such surety bond postings are required in order to operate in certain U.S. states or markets. Surety bonds issued as at December 31, 2017 and December 31, 2016 totaled $40.7 million and $18.8 million, respectively.

We do not reasonably expect any presently known trend or uncertainty to affect our ability to continue using these arrangements.

Transactions Between Related Parties

Certain transactions between the Trust and its subsidiaries meet the definition of related party transactions, including intercompany notes and administrative service fees between the Trust and its subsidiaries. These transactions are eliminated on consolidation and are not disclosed in the Trust's consolidated financial statements.

All related party transactions are in the normal course of operations and have been measured at the agreed to exchange amounts, which are the amounts of consideration established and agreed to by the related parties.

Discussion of Fourth Quarter 2017 Operations
For the three month period ended December 31, 2017 and December 31, 2016

Revenue

For the three month period ended December 31, 2017, revenue was $248.5 million, representing an increase of 45.0% from $171.4 million for the three month period ended December 31, 2016. The period-over-period revenue was higher primarily due to revenues associated with the USG&E Acquisition at the beginning of the third quarter of 2017.

Electricity

Electricity revenue for the three month period ended December 31, 2017 was $210.5 million, representing an increase of 31.1% from $160.6 million for the three month period ended December 31, 2016, primarily as a result of a 24.2% increase in volume and a 5.5% higher average retail rates per unit. Electricity volumes for the three month period ended December 31, 2017 were 2,189,000 MWh, representing an increase of 24.2% from 1,762,000 MWh for the three month period ended December 31, 2016, with the increase primarily due to higher average customers associated with the USG&E Acquisition at the beginning of the third quarter of 2017.

Natural Gas

Natural gas revenue for the three month period ended December 31, 2017 was $33.3 million, representing an increase of 265.5% from $9.1 million for the three month period ended December 31, 2016, primarily as a result of a 172.3% increase in volume and 34.2% higher average retail rate per unit. Natural gas volumes for the three month period ended December 31, 2017 were 5,120,000 MMBtu, representing an increase of 172.3% from 1,880,000 MMBtu for the three month period ended December 31, 2016, with the increase primarily due to higher average customers associated with the USG&E Acquisition at the beginning of the third quarter of 2017.

Solar Revenue

Solar revenue for the three month period ended December 31, 2017 was $2.4 million, representing an increase from revenues of $0.2 million for the three month period ended December 31, 2016, reflecting sales growth following the transition from the legacy reseller model.

Fee Revenue

Fee revenue, consisting of various fees received from customers, for the three month period ended December 31, 2017 was $2.2 million compared to $1.5 million for the three month period ended December 31, 2016.

Gross Margin

For the three month period ended December 31, 2017, gross margin was $54.8 million, representing an increase of 46.2% from $37.5 million for the three month period ended December 31, 2016. Gross margin for the three month period ended December 31, 2017 was 22.1% of total revenue compared to 21.9% for the three month period ended December 31, 2016.

The period-over-period increases in gross margin are attributable to the addition of the customer portfolio acquired from USG&E at the beginning of the third quarter of 2017. Slightly higher period-over-period gross margins as a percentage of revenue is consistent with the addition of the higher-margin USG&E portfolio, but offset by recent trends resulting from the increased mix of lower-margin commercial and municipal aggregation customers in the portfolio.

Electricity

Electricity gross margin for the three month period ended December 31, 2017 was $38.8 million, representing an increase of 20.0% from $32.3 million for the three month period ended December 31, 2016. For the three month period ended December 31, 2017, electricity gross margin per unit was $17.73/MWh, and electricity gross margin accounted for 18.4% of electricity revenues, representing a decrease from $18.36/MWh and 20.1%, respectively, for the three month period ended December 31, 2016. Gross margins in the current quarter were higher than the prior year comparable period due to the addition of the customers acquired from USG&E. Lower period-over-period gross margin per unit and gross margins as a percentage of revenue is consistent with recent trends resulting from the increased mix of lower-margin commercial and municipal aggregation customers in the portfolio, partially offset by the addition of the higher-margin USG&E portfolio.

Natural Gas

Natural gas gross margin for the three month period ended December 31, 2017 was $14.4 million, representing a 314.6% increase from $3.5 million for the three month period ended December 31, 2016. For the three month period ended December 31, 2017, natural gas gross margin per unit was $2.82/MMBtu, and natural gas gross margin accounted for 43.3% of natural gas revenues, representing increases from $1.85/MMBtu and 38.1%, respectively, for the three month period ended December 31, 2016. The increase in gross margin and gross margins per unit in the quarter were primarily attributable to the acquisition of the USG&E customer portfolio at the beginning of the third quarter of 2017.

Other

Gross margin for the three month period ended December 31, 2017 also included solar gross margin of negative $0.7 million and various fees received from customers of $2.2 million. For the three month period ended December 31, 2016, solar gross margin was $0.2 million and revenues from various fees received from customers were $1.5 million.

Selling Expenses

For the three month period ended December 31, 2017, selling expenses were $11.2 million, representing an increase from $6.6 million for the three month period ended December 31, 2016. Selling expenses for the three month period ended December 31, 2017 amounted to 4.5% of revenue compared to 3.8% for the three month period ended December 31, 2016. These expenses consist of:

(a) Upfront electricity and natural gas customer acquisition costs for the three month period ended December 31, 2017 of $5.1 million (amounting to $35 per customer acquired), representing an increase from $1.3 million for the three month period ended by December 31, 2016 (amounting to $14 per customer acquired), with the higher costs in the fourth quarter of 2017, as compared to the prior comparable period as well as recent quarters, being primarily a result of the impact of increased additions and increased upfront selling costs per customer following the USG&E Acquisition, which represents an increased mix of sales channels associated with higher upfront customer acquisition costs.

(b) Residual-based electricity and natural gas commissions for the three month period ended December 31, 2017 of $5.3 million (amounting to 2.2% of revenues), representing an increase from $4.3 million for the three month period ended December 31, 2016 (amounting to 2.5% of revenues). Residual-based commissions were higher in the third quarter of 2017, primarily due to the addition of residual-based commissions associated with the USG&E Acquisition at the beginning of the third quarter of 2017.

(c) Solar selling expenses for the three month period ended December 31, 2017 of $0.8 million compared to $1.0 million for the three month period ended December 31, 2016.

General and Administrative Expenses

General and administrative expenses for the three month period ended December 31, 2017 were $26.0 million, compared to $17.3 million for the three month period ended December 31, 2016, as set forth in the tables below, with the increase being primarily attributable to the increased cost-base following the USG&E Acquisition in mid-2017.

General and Administrative Expenses
(in $ millions and % of revenue)

	Quarter ended December 31, 2017		Quarter ended December 31, 2016	
	$	%	$	%
POR fees / bad debt	$3.1	1.2%	$1.7	1.0%
Processing costs	1.7	0.7%	1.1	0.6%
Human resources	9.0	3.6%	6.5	5.0%
Gross receipts taxes and other taxes	3.6	1.4%	1.9	1.1%
Professional and consultant fees	1.1	0.4%	0.7	0.4%
Legal and regulatory	0.6	0.2%	0.8	0.5%
Solar operating expenses	1.3	0.5%	1.9	1.1%
Other	5.2	2.1%	2.7	1.6%
Legal reserve and associated legal fees	0.4	0.2%	—	—%
Total	**$26.0**	**10.5%**	**$17.3**	**10.1%**

General and administrative expenses incurred during the three month ended December 31, 2017 were made up of the following categories:

(a) POR fees/bad debt represent fees paid to the LDCs pursuant to POR programs, under which the LDCs assume credit risk associated with customer non-payment and bad debt costs incurred in markets where the Company does not operate under a POR program, which exposes the Company to customer credit risk. The POR fees/bad debt costs for the three month period ended December 31, 2017 were $3.1 million, representing 1.2% of revenue, compared to $1.7 million for the three month period ended December 31, 2016, representing 1.0% of revenue for that period, with the increase primarily due to the USG&E Acquisition at the beginning of the third quarter of 2017.

(b) Processing costs for the three month period ended December 31, 2017 of $1.7 million include various data processing and information technology costs incurred to service our customers and sales force. This compares to $1.1 million for the three month period ended December 31, 2016, with the increase primarily due to the USG&E Acquisition.

(c) Human resource costs for the three month period ended December 31, 2017 of $9.0 million, consist of costs incurred in relation to the Company's employee base, temporary staff and independent contractors compared to costs in the prior comparable period in 2016 of $6.5 million, with the increase primarily due to the USG&E Acquisition.

(d) Gross receipts taxes and other taxes for the three month period ended December 31, 2017 of $3.6 million, representing 1.4% of revenue, represent operational taxes in various U.S. states and jurisdictions and are primarily driven by revenue, and compared to $1.9 million, representing 1.1% of revenue, incurred in the prior comparable period, with the increase primarily attributable to increased revenues associated with the USG&E Acquisition as well as an accrual of potential sales tax exposures for prior periods of $1.6 million arising out of various ongoing sales tax audits.

(e) Professional and consultant fees for the three month period ended December 31, 2017 of $1.1 million represent audit, tax, investor relations, share registry, valuation, due diligence, internal controls consulting and other fees and compares to $0.7 million in prior comparable period in 2016.

(f) Legal and regulatory costs for the three month period ended December 31, 2017 of $0.6 million represent external legal fees and compares to $0.8 million in the prior comparable period in 2016.

(g) Solar operating expenses for three month period ended December 31, 2017 of $1.3 million represent costs associated with the operation of the solar business and compares to $1.9 million in the prior comparable period in 2016.

(h) Other costs for the three month period ended December 31, 2017 of $5.2 million represent the balance of corporate, operational and marketing related expenses incurred to operate the business. These costs compare to $2.7 million in the prior comparable period in 2016, with the current period being impacted by the USG&E Acquisition at the beginning of the third quarter of 2017.

(i) Legal reserve and associated legal fees for the three month period ended December 31, 2017 of $0.4 million, consisted of ongoing legal fees relating to the pending litigation and regulatory matters relating to prior sales and marketing practices. These legal fees incurred in the current quarter were excluded from Adjusted EBITDA and Distributable Cash.

Unit-Based Compensation

For the three month period ended December 31, 2017, unit-based compensation expense amounted to $0.1 million representing a decrease from $0.7 million for the three month period ended December 31, 2016. The expense reflects the fair value of the unit-based compensation based on the market price of the Units at the end of the period and the applicable vesting period.

Depreciation and Amortization

Depreciation and amortization for the three month period ended December 31, 2017 was $12.0 million, representing an increase from $9.4 million for the three month period ended December 31, 2016. The increases are primarily attributable to the amortization of the newly-established intangible assets related to the USG&E Acquisition at the beginning of the third quarter of 2017.

Finance Costs

Finance costs for the three month period ended December 31, 2017 were $5.2 million, representing an increase from $1.9 million for the three month period ended December 31, 2016. The higher finance fees for the three months ended December 31, 2017 as compared to the prior comparable period in 2016 were attributable to higher energy volumes as a result of the USG&E Acquisition at the beginning of the third quarter of 2017, increased usage of the credit facility, partially to fund the cash portion of the USG&E Acquisition and interest on the Term Loans which were entered into in 2017.

Change in Fair Value of Derivative Instruments

For the three month period ended December 31, 2017, the changes in unrealized gains or losses associated with derivative contracts were net gains of $32.2 million compared to net losses of $21.3 million for the three month period ended December 31, 2016.

Change in Fair Value of Derivative Instruments
(in millions)

	Quarter Ended December 31, 2017	Quarter Ended December 31, 2016
Forward electricity positions	$34.9	$19.9
Forward natural gas positions	(2.1)	2.2
Weather derivative positions	0.1	(0.1)
Forward currency positions	(0.7)	(0.7)
Change in fair value of derivative instruments	**$32.2**	**$21.3**

Change in Fair Value of Warrants

The change in fair value of warrant liability for the three month period ended December 31, 2017 was a gain of $0.3 million compared to a gain of $0.1 million for the three month period ended December 31, 2016. These gains and losses represent the mark-to-market valuation of the 750,000 Warrants issued to Macquarie Energy in connection with the Crius Supplier Agreement (as defined in the section entitled *"Liquidity and Capital Resources"* in this MD&A). The valuation of the Warrants is based on an option valuation model, and accordingly the non-cash gains and losses are the result of changes in the Unit price, volatility, yield, time to maturity and the risk-free rate over the period.

(Benefit from) Provision for Income Taxes

For the three month period ended December 31, 2017, the Trust recorded a benefit from income taxes of $3.2 million and for the three month period ended December 31, 2016, the Trust recorded a provision for income taxes of $2.4 million. The Trust was in a pre-tax income position for the quarter, and was in a net income position for the same period in the prior year after adjusting for permanent differences. The Trust's (benefit from) provision for income taxes relates to the Trust's U.S. subsidiaries. Deferred tax assets are recognized to the extent that the Trust believes that the likelihood of recognition is probable. The Trust also re-measured its deferred tax assets during the period to reflect the reduced corporate income tax rate pursuant to the passing of the U.S. *Tax Cuts and Jobs Act*.

Net Income

For the three month period ended December 31, 2017, net income was $36.0 million, compared to net income of $20.6 million for the three month period ended December 31, 2016, with the changes being attributable to the factors noted above. Net income is impacted by numerous non-cash items, some being a result of the structure of the Trust and its subsidiaries as well as the industry in which they operate. Accordingly, Management believes the additional non-IFRS financial measures of Adjusted EBITDA and Distributable Cash are useful metrics to be considered together with net income for evaluating the Trust's financial and operating performance, as they are measures that Management uses internally to assess performance.

Critical Accounting Estimates

The preparation of these consolidated financial statements requires the use of judgments, estimates and assumptions to be made in applying accounting policies that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities, at the date of the consolidated financial statements, and the reported income and expenses during the reporting period.

Judgment is commonly used in determining whether a balance or transaction should be recognized in the consolidated financial statements and estimates and assumptions are more commonly used in determining the measurement of recognized transactions and balances. However, judgment and estimates are often interrelated. As the basis for its judgments, Management uses estimates and related assumptions which are based on previous experience and various commercial, economic and other factors that are considered reasonable under the circumstances. These estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimate is revised. Actual outcomes may differ from these estimates under different assumptions and conditions.

Judgments, made by Management in the application of IFRS that have a significant impact on the consolidated financial statements relate to the following:

Revenue recognition

Accounts receivable includes an unbilled receivables component, representing the amount of energy consumed by customers as at the end of the period but not yet billed. Unbilled receivables are estimated by the Company using usage data available, multiplied by the current customer average sales price per unit.

Allowance for doubtful accounts

The Company reviews its accounts receivable at each reporting date to assess whether an allowance needs to be provided to reflect estimated amounts that will not be collected from customers. In particular, judgment by Management is required in the estimation of the amount and timing of collectability of accounts receivable, based on financial conditions, the aging of the receivables, customer and industry concentrations, the current business environment and historical experience.

Fair value of financial instruments

Determining the fair value of financial instruments requires judgment and is based on market prices or Management's best estimates if there is no market and/or if the market is illiquid. Where the fair value of financial instruments recorded cannot be derived from active markets, they are determined using valuation techniques including making internally generated adjustments to quoted prices in observable markets. The inputs to these models are taken from observable markets where possible, but where this is not feasible, a degree of judgment is required in establishing fair values. The judgment includes consideration of inputs such as liquidity risk, credit risk and volatility of the underlying commodity price. Changes in assumptions about these factors could affect the reported fair value of financial instruments.

Impairment of intangible or non-financial assets

In assessing the recoverable amount of intangible assets or non-financial assets for potential impairment, the Company evaluates value in use and fair value less costs of disposal. In doing so, the Company's market capitalization is considered, as well as recent market transactions or other market indicators, future cash flows, including the discount rate to be used to calculate the present value of those cash flows. These calculations require the use of estimates. If these estimates change in the future, the Company may be required to record impairment charges related to intangible or other non-financial assets.

Deferred taxes

Significant Management judgment is required to determine the amount of deferred tax assets that can be recognized, based upon the likely timing and the level of future taxable income realized, including the usage of tax-planning strategies.

Useful life of property and equipment and intangible assets

The amortization method and useful lives reflect the pattern in which Management expects the asset's future economic benefits to be consumed by the Company, including customer attrition rates.

Acquisition accounting

Management uses judgment to determine whether an acquisition meets the criteria of an asset acquisition or a business combination by reviewing inputs, processes, and outputs within a transaction. All identifiable assets, liabilities and contingent liabilities acquired in an asset acquisition or business combination are recognized at fair value on the date of acquisition. Estimates are used to calculate the fair value of these assets and liabilities as at the date of acquisition.

Classification of Trust Units as equity

Units issued by the Trust give the holder the right to put the Units back to the Trust in exchange for cash. IAS 32 *Financial Instruments: Presentation* establishes the general principle that an instrument which gives the holder the right to put the instrument back to the issuer for cash should be classified as a financial liability, unless such instrument has all of the features and meets the conditions of the IAS 32 "puttable instrument exemption". If these "puttable instrument exemption" criteria are met, the instrument is classified as equity. The Trust has examined the terms and conditions of its Trust Indenture and classifies its outstanding Units as equity because the Units meet the "puttable instrument exemption" criteria as there is no contractual obligation to distribute cash.

Legal Contingencies

Reserves are established for such legal and regulatory claims based upon the probability and estimability of losses and to fairly present, in conjunction with the disclosures of these matters in the Company's financial statements and Management's view of the Company's exposure. The Company continuously reviews outstanding claims with internal as well as external counsel to assess probability and estimates of loss. The risk of loss is reassessed as new information becomes available and any such reserves are adjusted, as appropriate. The actual cost of resolving a claim may be substantially higher, or lower, than the amount of the recorded reserve.

New Standards and Accounting Policies Adopted

The consolidated financial statements have been prepared following the same accounting policies as those that were followed in the preparation of the Trust's prior year consolidated financial statements, with the exception of the following new standards:

The amendments to IAS 7 *Statement of Cash Flows* are part of the IASB's Disclosure Initiative and require an entity to provide disclosures that enable users of financial statements to evaluate changes in liabilities arising from financing activities, including both changes arising from cash flows and non-cash changes. On initial application of the amendment, entities are not required to provide comparative information for preceding periods. These amendments were effective for annual periods January 1, 2017. Application of the amendments resulted in additional disclosures in the consolidated financial statements of the Company.

The amendments to IAS 12 *Income Taxes* clarify that an entity needs to consider whether tax law restricts the sources of taxable profits against which it may make deductions on the reversal of that deductible temporary difference. Furthermore, the amendments provide guidance on how an entity should determine future taxable profits and explain the circumstances in which taxable profit may include the recovery of some assets for more than their carrying amount. Entities are required to apply the amendments retrospectively. However, on initial application of the amendments, the change in the opening equity of the earliest comparative period may be recognized in the opening retained earnings (or in another component of equity, as appropriate), without allocating the change between opening retained earnings and other components of equity. These amendments were effective for annual periods beginning January 1, 2017, however, they did not have an impact on the consolidated financial statements of the Company.

Future Accounting Pronouncements

Recent accounting pronouncements that are issued but not yet effective up to the date of issuance of the Company's consolidated financial statements are listed below.

The IASB issued amendments to IFRS 2 *Share-based Payment* that address three main areas: the effects of
vesting conditions on the measurement of a cash-settled share-based payment transaction; the classification of a share-based payment transaction with net settlement features for withholding tax obligations; and accounting where a modification to the terms and conditions of a share-based payment transaction changes its classification from cash settled to equity settled. On adoption, entities are required to apply the amendments without restating prior periods, but retrospective application is permitted if elected for all three amendments and other criteria are met. The amendments are effective for annual periods beginning on or after January 1, 2018, with early application permitted. The standard is not expected to have a material impact on the consolidated financial statements of the Company.

In July 2014, the IASB issued the final version of IFRS 9, *Financial Instruments*, bringing together the classification and measurement, impairment, and hedge accounting phases of the IASB's project to replace IAS 39, Financial Instruments: *Recognition and Measurement*. This version adds a new expected loss impairment model and limited amendments to classification and measurement for financial assets. The standard supersedes all previous versions of IFRS 9 and is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. Early application of previous versions of IFRS 9 (2009, 2010 and 2013) is permitted if the date of the initial application is before February 1, 2015. The Company elected not to adopt the standard early. The standard is not expected to have a material impact on the consolidated financial statements of the Company.

IFRS 15 *Revenue from Contracts with Customers* was released in May 2014 which focuses on a principles based five–step model which is required to be applied to all contracts with customers. The guidance amongst other things provides for (i) whether revenue should be recognized at a point in time or over time, which replaces the previous distinction between goods and services, (ii) identifies distinct performance obligations, accounting for contract modifications and accounting for the time value of money and (iii) new, increased requirements for disclosure of revenue in the financial statements. Furthermore, the standard specifies how to account for incremental costs of obtaining a contract and the costs directly associated with fulfilling a contract. Provided these costs are expected to be recovered, such costs will be capitalized, subsequently amortized over the useful life of customers and tested for impairment. IFRS 15 must be applied in an entity's first annual IFRS financial statements for periods beginning on or after January 1, 2018, with early adoption permitted. The Company will transition using the modified retrospective approach. The Company has evaluated the impact of the new revenue standard, as amended, on its financial statements and related disclosures, and believes the adoption of the new standard will not impact revenue recognition for the electricity and gas business. Revenue recognized for the solar installation business under Verengo will continue to be an over time revenue recognition model as the installation work is completed, but will change from the milestone method currently used to a cost-based input method upon the adoption of IFRS 15. This change is not expected to have a material impact to the Company's financial statements. Upon the adoption of IFRS 15, the Company's accounting for direct incremental costs of obtaining customer contracts (for example, one-time selling expenses and fees paid for new customer origination) and direct fulfillment costs will change because the new standard requires deferral and amortization of certain direct incremental costs, which are currently being expensed as incurred. Upon adoption, the potential impact of such deferral is expected to increase the Company's opening retained earnings balance in the range of $9,000 to $11,000. The change in the accounting for deferrable fulfillment costs is expected to be immaterial, with an expected incremental increase to the Company's opening retained earnings by less than $1,000. These potential adjustments have not yet been audited by our external auditors.

IFRS 16 *Leases* was issued by the IASB in January 2016. This guidance brings most leases onto the balance sheet for lessees under a single model, eliminating the distinction between operating and finance leases. Lessor accounting remains largely unchanged and the distinction between operating and finance leases is retained. Furthermore, per the standard, a lessee recognizes a right-of-use asset and a lease liability. The right-of-use asset is treated similarly to other non-financial assets and depreciated accordingly, and the liability accrues interest. The lease liability is initially measured at the present value of the lease payments payable over the lease term, discounted at the rate implicit in the lease. Lessees are permitted to make an accounting policy election, by class of underlying asset, to apply a method like IAS 17's operating lease accounting and not recognize lease assets and lease liabilities for leases with a lease term of 12 months or less, and on a lease-by-lease basis, to apply a method similar to current operating lease accounting to leases for which the underlying asset is of low value. IFRS 16 supersedes IAS 17 *Leases* and related interpretations, and is effective for periods beginning on or after January 1, 2019, with earlier adoption permitted if IFRS 15 has also been applied. The Company has not fully assessed the impact of this standard on the consolidated financial statements.

IFRIC 22 *Foreign Currency Transactions and Advance Consideration* was issued by the IASB in December 2016. This interpretation provides guidance where 1) there is consideration that is denominated or priced in a foreign currency; 2) an entity recognizes a prepayment or a deferred liability in respect of that consideration in advance of recognition of the related asset; and 3) where the prepayment asset or deferred income liability is non-monetary. The interpretation is effective for annual periods beginning on or after January 1, 2018. The interpretation is not expected to have a material impact on the consolidated financial statements of the Company.

IFRIC 23 *Uncertainty over Income Tax Treatments* was issued by the IASB in June 2017. This interpretation provides guidance to be applied in the determination of taxable profit or loss, tax bases, unused tax losses, unused tax credits and tax rates, when there is uncertainty over income tax treatments under IAS 12. The interpretation is effective for annual periods beginning on or after January 1, 2019. The interpretation is not expected to have a material impact on the consolidated financial statements of the Company.

Disclosure Controls and Procedures & Internal Controls over Financial Reporting

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to Management of the Trust as appropriate to allow timely decisions regarding required disclosure.

The Chief Executive Officer and Chief Financial Officer of the Trust are responsible for establishing and maintaining disclosure controls and procedures ("**DC&P**") and internal control over financial reporting ("**ICFR**"), as those terms are defined in National Instrument 52-109 — *Certification of Disclosure in Issuers' Annual and Interim Filings* ("**NI 52-109**").

The Chief Executive Officer and Chief Financial Officer of the Trust have concluded that, as at December 31, 2017, the Trust's DC&P have been designed and operate effectively to provide reasonable assurance that (i) material information relating to the Trust is made known to them by others, particularly during the period in which the annual filings are being prepared, and (ii) information required to be disclosed by the Trust in its annual filings, interim filings or other reports filed or submitted by the Trust under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. They have also concluded that the Trust's ICFR has been designed effectively to provide reasonable assurance regarding the reliability of the preparation and presentation of the financial statements for external purposes in accordance with IFRS, and were effective as at December 31, 2017.

It should be noted that, while the Chief Executive Officer and Chief Financial Officer of the Trust believe that the Trust's DC&P provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls will prevent all errors and fraud. A control system, no matter how well conceived or operated, can only provide reasonable, not absolute, assurance that the objectives of the control system are met.

ICFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external reporting purposes in line with IFRS. Management is responsible for establishing and maintaining appropriate ICFR in relation to the nature and size of the Trust. However, any system of ICFR has inherent limitations and can only provide reasonable assurance with respect to financial statement preparation and presentation.

The Trust's ICFR has been designed based on the control framework established in *Internal Control - Integrated Framework* published in 2013 by The Committee of Sponsoring Organizations of the Treadway Commission. There were no changes to the Trust's ICFR that occurred during the year ended December 31, 2017 that materially affected, or are reasonably likely to affect, the Trust's ICFR.

Limitation on Scope of Design

The Chief Executive Officer and Chief Financial Officer of the Trust have limited the scope of design of DC&P and ICFR to exclude controls, policies and procedures of any business acquired by the Trust during the year ended December 31, 2017, including the Verengo acquisition, which closed in May 2017 and the USG&E Acquisition which closed in July 2017. This limitation on scope is in accordance with section 3.3(1)(b) of NI 52-109, which allows an issuer to limit its design of DC&P and ICFR to exclude controls, policies and procedures of a business that the issuer acquired not more than 365 days before the last day of the period covered by this MD&A.

Non-IFRS Financial Measures

Statements throughout this MD&A make reference to EBITDA, Adjusted EBITDA, Distributable Cash, Total Distributions, Payout Ratio, Adjusted Working Capital, Total Cash and Availability and Maintenance Capital Expenditures which are non-IFRS financial measures commonly used by financial analysts in evaluating the financial performance of companies, including companies in the energy industry. Accordingly, Management believes these non-IFRS financial measures may be useful metrics for evaluating the Trust's financial performance as they are measures that Management uses internally to assess performance, in addition to IFRS measures. As there is no generally accepted method of calculating these non-IFRS financial measures, these terms as used herein are not necessarily comparable to similarly titled measures of other companies. These non-IFRS financial measures have limitations as analytical tools and should not be considered in isolation from, or as an alternative to, net income (loss), cash flow provided from (used in) operating activities or other data prepared in accordance with IFRS. Additionally, there may be certain items included or excluded from these non-IFRS financial measures that are significant in assessing the Trust's operating results and liquidity.

Forward-Looking Statements

This MD&A contains forward-looking statements and forward-looking information (collectively, "**forward-looking statements**") including, without limitation, statements relating to non-IFRS financial measures; the confidence of Management and the Board; the Trust's outlook, strategy, and ability to execute its business objectives; future payments owed to the Company; the electricity, natural gas and solar industries; governmental regulatory regimes; acquisitions and strategic partnerships; marketing channels; customers and customer growth; hedging strategies; risk management; market risk; credit risk; off-balance sheet arrangements; related party-transactions; liquidity and capital resources; critical accounting estimates; ICFR; potential transactions; results of operations; financial position or cash flows; expenses and distributions to Unitholders. Often, but not always, forward-looking statements can be identified by the use of words such as "plans", "expects" or "does not expect", "is expected", "budget", "scheduled", "estimates", "forecasts", "intends", "anticipates" or "does not anticipate", or "believes", or describes a "goal", or variation of such words and phrases or state that certain actions, events or results "may", "could", "would", "might" or "will" be taken, occur or be achieved. All forward-looking statements reflect the Trust's beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. All of the Trust's forward-looking statements are qualified by (i) the assumptions that are stated or inherent in such forward-looking statements, and (ii) the risks described in the section entitled *"Financial Instruments and Risk Management"* in this MD&A and in the sections entitled *"Risk Factors"* and *"Forward-Looking Statements"* in the annual information form of the Trust for the fiscal year ended December 31, 2016, dated March 16, 2017, which is available on SEDAR under the Trust's issuer profile at www.sedar.com and on the Trust's website at www.criusenergytrust.ca. Forward-looking statements involve known and unknown risks, future events, conditions, uncertainties and other factors which may cause the actual results, performance or achievements to be materially different from any future results, prediction, projection, forecast, performance or achievements expressed or implied by the forward-looking statements. Although the Trust has attempted to identify important factors that could cause actual actions, events or results to differ materially from those described in forward-looking statements, there may be other factors that cause actions, events or results not to be as anticipated, estimated or intended. There can be no assurance that forward-looking statements will prove to be accurate, as actual results and future events could differ materially from those anticipated in such statements. Accordingly, readers should not place undue reliance on forward-looking statements. The Trust disclaims any intention or obligation to update or revise any forward-looking statements whether as a result of new information, future events, or otherwise, except in accordance with applicable securities laws.