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COUNTRYSIDE
POWER INCOME FUND

AR/S
12-31-06

Annual Information Form

For the year ended December 31, 2006

March 26, 2007

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FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Information Form and any documents incorporated by reference may constitute "forward-looking" statements that involve known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievement of the Fund or the Business, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. When used in this Annual Information Form, such statements use such words as "may", "will", "expect", "believe", "plan" and other similar terminology. These statements reflect current expectations regarding future events and operating performance and speak only as of the date of this Annual Information Form. Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not such results will be achieved. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors discussed under "Risk Factors". Although the forward-looking statements contained in this Annual Information Form are based upon what the Manager (defined below) believes are reasonable assumptions, the Fund cannot assure investors that actual results will be consistent with these forward-looking statements. These forward-looking statements are made as of the date of this Annual Information Form, and neither the Fund nor any other person assumes any obligation to update or revise them to reflect new events or circumstances.

COUNTRYSIDE POWER INCOME FUND STRUCTURE

The Fund

Countryside Power Income Fund (the "Fund") is an unincorporated, open-ended, limited purpose trust established under the laws of the Province of Ontario on February 16, 2004 pursuant to a declaration of trust (the ''Declaration of Trust''). The Declaration of Trust was amended and restated on April 8, 2004, the date of the closing of the initial public offering of trust units of the Fund (''IPO Closing''). The Fund has invested, indirectly through Countryside Canada Power Inc. ("Countryside Canada"), in two district energy systems located in Charlottetown, Prince Edward Island (the ''PEI District Energy System'') and London, Ontario (the ''London District Energy System'', together with the PEI District Energy System, the ''District Energy Systems''), two gas-fired cogeneration facilities located in California (the ''California Cogen Facilities'') and a gas-fired cogeneration facility being developed adjacent to the London District Energy System (the "London Cogen Facility"). The District Energy Systems have approximately 122 MW of thermal and electric generation capacity, the California Cogen Facilities have approximately 94 MW (gross output) of electric generation capacity and sold approximately 600,000 thousand pounds of steam in 2006 and upon completion the London Cogen Facility is expected to have 19 MW (gross output) of electric generation capacity (gross output) and is expected to sell approximately 303,100 thousand pounds of steam annually. In addition, the Fund holds an allowed senior secured claim in the amount of approximately US $66 million (the "Allowed Secured Claim") in the pending

Chapter 11 bankruptcy proceeding of US Energy Biogas Corp. ("USEB") and its subsidiaries in the United States Bankruptcy Court for the Southern District of New York (the "USEB Bankruptcy"). USEB owns 23 renewable power generation and utility infrastructure projects (the ''Renewable Energy Projects'') located in the United States, which currently have approximately 52 MW of electric generation capacity and sold approximately 660,000 MMBtus of boiler fuel in 2006.

The registered and head office of the Fund is located at 495 Richmond Street, Suite 920, London, Ontario, Canada N6A 5A9.

Countryside Canada Power Inc.

Countryside Canada Power Inc. ("Countryside Canada") is a wholly owned subsidiary of the Fund. Countryside Canada is a corporation incorporated under the laws of Canada pursuant to the Canada Business Corporations Act. Countryside Canada owns 100% of the stock of Countryside District Energy Corp. ("Countryside District Energy"), 100% of the preferred stock and 75% of the common stock of Countryside London Cogeneration Corp. ("Countryside London Cogeneration") and 100% of the stock of Countryside US Holding Corp. ("Countryside Holding"). Countryside Canada holds 100% of the Allowed Secured Claim.

Countryside District Energy Corp.

On January 1, 2007 Countryside Canada Acquisition Inc., Countryside District Energy Holdings Corp. and Countryside District Energy Corp. amalgamated into the amalgamated corporation, Countryside District Energy. Country District Energy is a wholly owned subsidiary of Countryside Canada. Countryside District Energy is a corporation incorporated under the laws of Ontario pursuant to the Ontario Business Corporation Act. Countryside District Energy owns 100% of the District Energy Systems.

Countryside London Cogeneration Corp.

Countryside London Cogeneration is a subsidiary of Countryside Canada, which owns 100% of the preferred shares and 75% of the common shares of Countryside London Cogeneration. Countryside Ventures LLC (the "Manager") owns the remaining 25% of the common shares of Countryside London Cogeneration. Countryside London Cogeneration is a corporation incorporated under the laws of Ontario pursuant to the Ontario Business Corporation Act. Countryside London Cogeneration owns the London Cogeneration Facility.

Countryside US Holding Corp.

Countryside Holding is a wholly owned subsidiary of Countryside Canada. Countryside Holding is a Delaware Corporation incorporated pursuant to the Delaware General Corporation Law. Countryside Holding owns 100% of the preferred membership interests and 75% of the subordinate membership interests of Ripon Power LLC ("Ripon Power") and 100% of the shares of Countryside U.S. Power Inc. ("Countryside U.S. Power").

Countryside U.S. Power Inc.

Countryside U.S. Power is a Delaware corporation incorporated pursuant to the Delaware General Corporation Law. Countryside U.S. Power is party to a Development Agreement by and between Countryside U.S. Power and an indirect subsidiary of Duke Energy Corporation ("Duke Energy").

Ripon Power LLC

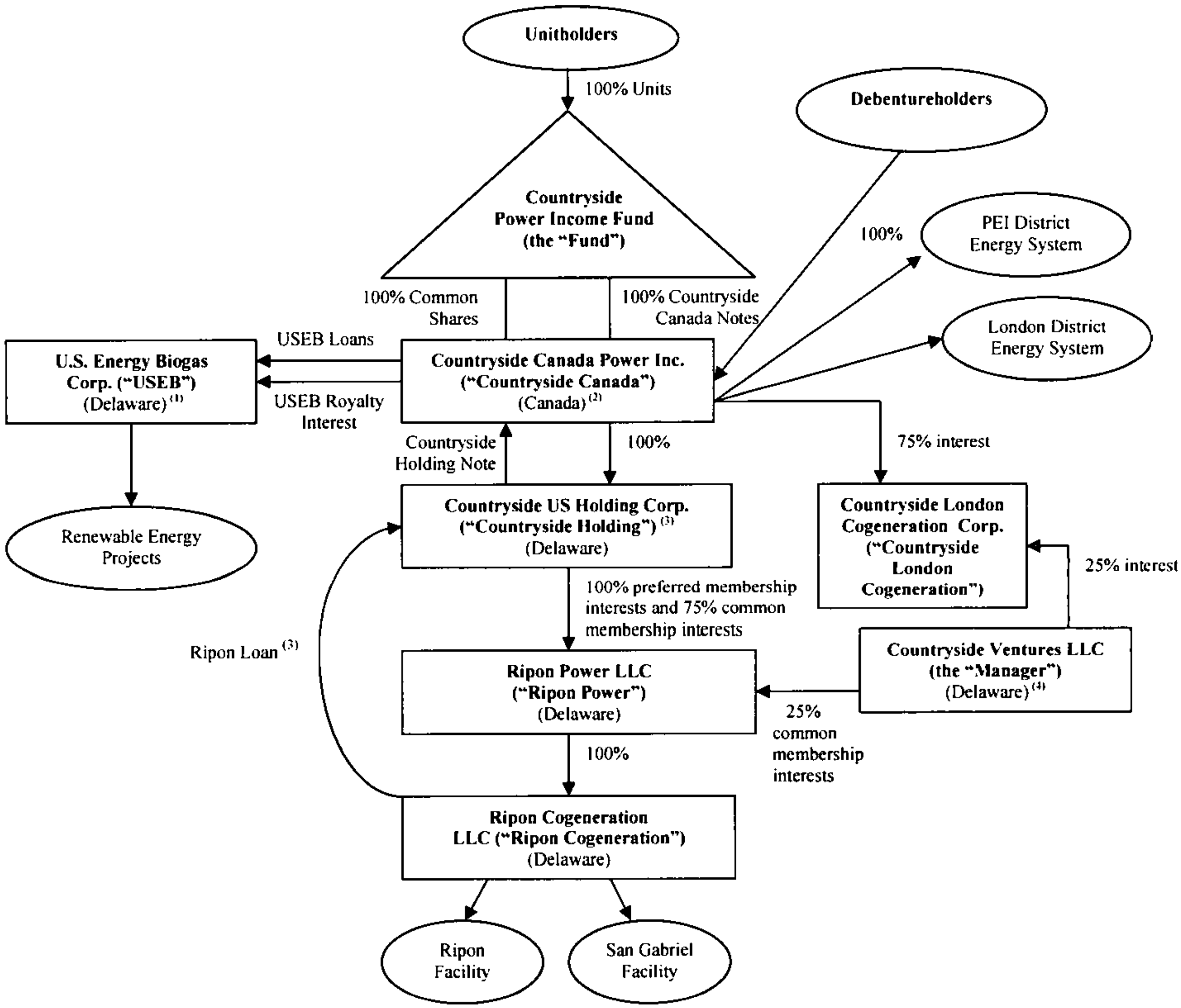
Ripon Power is a subsidiary of Countryside Holding which owns 100% of the preferred membership interests and 75% of the subordinate membership interests of Ripon Power. The Manager owns 25% of the subordinate membership interests of Ripon Power (the "Manager's Ripon Subordinated Interest"). Ripon Power is a Delaware limited liability company formed under the Delaware Limited Liability Company Act. Ripon Power owns 100% of the membership interests of Ripon Cogeneration LLC ("Ripon Cogeneration").

Ripon Cogeneration LLC

Ripon Cogeneration is a wholly owned subsidiary of Ripon Power. Ripon Cogeneration is a Delaware limited liability company formed under the Delaware Limited Liability Company Act. Ripon Cogeneration owns 100% of the California Cogen Facilities.

The following chart illustrates the primary structural, contractual and ownership relationships of the Fund:

Organization Chart



1. USEB indirectly owns a 50% interest in the Renewable Energy Projects based in Illinois and a 100% interest in the Renewable Energy Projects located outside of Illinois. The remaining 50% interest in the Illinois-based Renewable Energy Projects is owned by Landgas of Illinois Corp.

2. Countryside Canada owns its interest in the PEI District Energy System and the London District Energy System indirectly through Countryside District Energy, its wholly-owned subsidiary.

3. Countryside Holding holds a US$52 million project loan owed by Ripon Cogeneration (the "Ripon Loan").

4. The Manager was granted 25% subordinated interests in Ripon Power and Countryside London Cogeneration in accordance with its long-term incentive plan entitlement under the modified management arrangements. See "Management and Administration Agreements– Management Agreement".

GENERAL DEVELOPMENT OF THE BUSINESS

History of the Fund

Pursuant to a Prospectus dated March 29, 2004, the Fund completed its Initial Offering on April 8, 2004 and issued 14,905,366 Trust Units at a price of $10.00 per Unit.

In connection with the Initial Offering, the Fund acquired, through Countryside Canada Acquisition Inc. ("Countryside Acquisition") 100% of USE Canada Holdings Corp. the indirect owner of the District Energy Systems described under the heading "Description of the Business – The District Energy Systems". A Business Acquisition Report describing the details of this transaction in full was filed with the Ontario Securities Commission (OSC) on June 22, 2004, and is incorporated by reference in this annual information form. A copy of this report can be found on www.sedar.com. On such date the Fund also acquired, amended and made additional advances in respect of the USEB Loans and acquired the USEB Royalty Interest both described under the heading "Description of the Business – Advantages of Renewable Energy Projects".

The Fund also received $30,400,000 representing the proceeds of a new long-term debt facility (the "New Credit Facility") through Countryside Acquisition.

On June 29, 2005, the Fund, through a subsidiary, completed the indirect acquisition of Ripon Power, formerly Lightyear Rockland Partners LLC, whose principal asset is Ripon Cogeneration, a California-based power generation company, for consideration of approximately US$95.3 million or approximately $116.9 million, based on the Bank of Canada noon spot rate of exchange on June 29, 2005. The California Cogen Facilities consist of the Ripon cogeneration plant ("Ripon Facility") located near San Francisco, California and the San Gabriel cogeneration plant ("San Gabriel Facility") located near Los Angeles, California. In connection with this transaction, the Fund, through Countryside Acquisition, entered into the Amended Credit Facility (as defined below) in the amount of $80 million, all of which was drawn upon closing of the Acquisition. The Fund's short form prospectus for its second public offering, dated November 8, 2005 (the "2005 Prospectus") contains a more detailed description of the Ripon Power acquisition (see 2005 Prospectus, "The Acquisition", pp 5-7). A copy of the 2005 Prospectus can be found on www.sedar.com. A Business Acquisition Report describing the details of this transaction in full was filed with the Ontario Securities Commission ("OSC") on September 12, 2005 and is incorporated by reference in this Annual Information Form. A copy of this report can be found on www.sedar.com.

On September 23, 2005, the Fund announced an increase in its monthly distribution of $0.01 per Unit annually. The first distribution under the new rate was paid on or about October 31, 2005 to Unitholders of record on September 30, 2005.

Coincident with the distribution increase, the Fund announced a plan modifying the Fund's existing executive management arrangements. Under the modified arrangements, the Manager, a company independent of the Fund, provides management and administrative services to the Fund as well as new growth opportunities under long-term arrangements. The Manager employs the Fund's former executive management team on a full-time basis as well as its administrative and development staff. The Fund has a right of first offer on all investment opportunities developed by the Manager that meet the Fund's investment criteria. The Manager also is entitled to receive subordinated interests in new assets, acquisitions and investments acquired or made by the Fund's subsidiaries and originated, structured or developed through the efforts of the Manager including subordinated interests in Ripon Power and Countryside London Cogeneration. Such subordinated interests are exchangeable by the Manager and the Fund into Fund Units under certain terms and conditions. See "The Management and Administration Agreements".

Pursuant to the 2005 Prospectus, the Fund and Countryside Canada completed a public offering on November 14, 2005 (the "Second Offering") and issued, respectively, 4,720,000 Trust Units for gross proceeds of $44,132,000 at a price of $9.35 per Unit and US$55,000,000 aggregate principal amount of 6.25% exchangeable unsecured subordinated debentures (the "Debentures") due October 31, 2012 at a price of US $1,000 per Debenture. The Fund and Countryside Canada, through their subsidiaries, used the proceeds from the Second Offering to, among other things, repay approximately $30.5 million of the outstanding balance under the Amended Credit Facility, acquire and restructure project-related debt encumbering the California Cogeneration Facilities (the "Ripon Loan"), from a syndicate of U.S. based lenders and fund certain working capital needs.

On October 16, 2006 Countryside London Cogeneration executed a 20-year combined heat and power ("CHP") generation contract with the Ontario Power Authority ("OPA") which was awarded through a competitive bidding process. As a result, the Fund is constructing the London Cogen Facility for an estimated cost of $27 million.

On October 31, 2006, the Department of Finance (Canada) announced the "Tax Fairness Plan" whereby the income tax rules applicable to certain publicly listed trusts and partnerships will be significantly modified. In particular, certain income of (and distributions made by) these entities will be taxed in a manner similar to income earned by (and distributions made by) a corporation. These proposals will be effective for the 2007 taxation year with respect to trusts which commence public trading after October 31, 2006, but the application of the rules will be delayed to the 2011 taxation year with respects to trusts which were publicly listed prior to November 1, 2006 (although the announcement suggested that this transitional relief could be lost under certain circumstances, including the "undue expansion" of an income trust). See "Risk Factors-Risks Related to the Structure of the Fund-Tax Related Risks".

On November 29, 2006 USEB and various of its subsidiaries filed voluntary petitions seeking a reorganization under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York.

On January 15, 2007 the Fund announced that, through a mediation directed by the Bankruptcy Court, the Fund reached an agreement in principle with U.S. Energy Systems Inc. ("USEY") and USEB resolving all outstanding issues between the parties (the "USEB Settlement").

Among other things, the USEB Settlement provided for Countryside Canada to have the USEB Allowed Claim of US$99,000,000 (or approximately CAD$116,000,000 at the then current exchange rate) in the chapter 11 cases of USEB and its subsidiaries. USEB has paid down approximately US$33,000,000 of the USEB Allowed Claim of which US $30 million has been applied to pay down the Amended Credit Facility and the remaining balance is expected to be received on or before maturity at May 31, 2007. The outstanding principal amounts bear cash interest at a rate of 10% per annum from February 1, 2007, payable monthly in U.S. dollars to the Fund. The USEB Allowed Claim is secured by the same collateral which secured the USEB Loan; i.e. first liens on substantially all of the assets of USEB. The parties to the USEB Settlement also agreed to exchange general releases. The USEB Settlement was approved in principle by the Bankruptcy Court on February 1, 2007 and was formally approved by order of the Bankruptcy Court on February 16, 2007. Such order is now final and non-appealable. The USEB Settlement is now effective. (See "Renewable Energy Projects - USEB Bankruptcy")

The USEB bankruptcy filing and its related payment default constituted a cross default under the Fund's Amended Credit Facility. The lenders under the Amended Credit Facility granted two waivers of the cross-default including a waiver granted on or about January 25, 2007 which among other things (i) waived the cross-default until May 31, 2007, (ii) reinstated the Amended Credit Facility with a total availability of approximately C$55 million, (iii) permitted Unitholder distributions and permitted investments (including the London Cogen Facility) under the existing terms of the Amended Credit Facility, (iv) approved the USEB Settlement provided that the US$30 million payment of the USEB Allowed Claim due on or before March 31, 2007 was applied to pay down the Amended Credit Facility provided further such amount could thereafter be redrawn subject to compliance with the terms of the Amended Credit Facility, (v) required Countryside Canada and Countryside US Holding to provide additional collateral relating to Ripon Power and Ripon Cogeneration and (vi) required the Manager to waive certain rights respecting the Manager's Ripon Subordinated Interest which was originally provided to the Manager in connection with the origination and acquisition of Ripon Cogeneration in 2005, in order to facilitate the Lenders' realization on the new collateral in the event of an event of default under the Amended Credit Facility. (See "Risks Related to the Structure of the Fund - Amended Credit Facility")

In order to accommodate the lending syndicate's requirement that the Manager waive certain rights respecting the Manager's Ripon Subordinated Interest, the board of trustees of the Fund entered into an agreement with the Manager to purchase, on June 29, 2007 (or before in certain circumstances), 85% of the Manager's Ripon Subordinated Interest for cash and Fund units equal to $16,026,111 based on a unit price of $8.23. Under the prior arrangement, the Manager's Ripon Subordinated Interest could be exchanged for units of the Fund on or after June 29, 2007 (or before in certain circumstances) at the option of either the Fund or the Manager (subject to regulatory approval). The consideration to be paid will comprise a minimum of 10% cash and will provide the Fund with an option to increase the cash component up to 25% of the total consideration if the board of trustees deems such payment to be economically beneficial to the Fund.

After completion of the purchase of the 85% of the Manager's Subordinated Interest, the Manager will hold 3.75% and the Fund will hold 96.25%, respectively, of the subordinated interest in Ripon Power.

Fund's Objectives and Strategy

Historically the Fund's objective has been to maintain the stability and sustainability of cash distributions to Unitholders and increase, when prudent, cash distributions per Unit. In order to achieve these objectives, the Fund has focused on enhancing current operational practices of the Business, pursuing internal growth and expansion opportunities and making additional investments in power generation and utility infrastructure, including, among others, cogeneration projects, green energy projects and district energy systems.

On February 9, 2006 the Fund announced that the Trustees engaged Lehman Brothers Inc. to assist in the ongoing process of identifying and considering strategic alternatives available to the Fund to maximize Unitholder value.

The strategic review process had been advanced and formalized in response to: (i) the expected impact to the Fund of the USEB Settlement and (ii) the Canadian government's proposed legislation to tax income trusts. The strategic review process has been considering a range of value enhancement alternatives that involve a comprehensive review of the Fund's existing capital structure, growth strategy, and access to capital markets as well as prospects as an income trust. The process has been considering such alternatives as a sale of the Fund (or its segments), a conversion to a corporate structure, and/or a recapitalization. To date, the board of trustees is encouraged by the results of the sale process and will continue to weigh those plans against a stand alone strategy with a view to maximizing unitholder value. A stand alone strategy may comprise several options, including a continuation of operations under the existing trust structure and the Fund's use of proceeds from the expected monetization of the USEB Allowed Claim to (i) fund (with the incurrence of additional leverage) the re-powering of the California Cogen Facilities and the new 17 megawatt London Cogen Facility and/or (ii) a recapitalization which may involve a re-leveraging of the Fund with a return of capital to unitholders through a special distribution or unit buy back. Under a potential stand alone plan, any new growth-related investment or recapitalization strategy would be designed to provide accretive distributable cash flow to unitholders. However, the Fund currently does not intend to reinvest the proceeds from any future monetization of the Allowed Secured Claim until the strategic review process has been completed. The board of trustees of the Fund expects the strategic review process to be completed by the end of June 2007.

Operating Strategy

The Fund's operating strategy is to continue to retain the services of qualified and experienced operators, and, when required, hire experienced operations personnel or contract with firms with the requisite operational expertise.

Since the closing of the Offering, the Renewable Energy Projects and the District Energy Systems have continued to be operated and managed by the employees of USEB and Countryside District Energy, respectively, which have operated the Renewable Energy Projects and District Energy Systems for a number of years. The employees of Countryside District Energy will operate the London Cogen Facility. Administration and operations oversight of the Renewable Energy Projects is currently performed by USEY. The power generation equipment for 10 of the Renewable Energy Projects is operated by outside operators under contract. GE/Jenbacher is the operator for eight of these 10 Renewable Energy Projects. The California Cogen Facilities are operated by North American Energy Services ("NAES") under contract. Most of the employees employed by NAES at the California Cogen Facilities have worked at the California Cogen Facilities for a number of years.

In addition, the Manager employs a management team which monitors the Fund's indirect investments in the District Energy Systems, the USEB Allowed Claim, the California Cogeneration Facilities and the London Cogen Facility and evaluates and presents investment opportunities to the Fund and its subsidiaries. These individuals have extensive experience with the Business and managing the growth of energy businesses and projects.

Acquisition and Investment Strategy

Subject to the conclusions reached in the strategic review process and rules promulgated under the Tax Fairness Plan, the Fund intends to acquire or invest in additional projects only if the Fund believes that the acquisition or investment will result in an increase in cash distributions per Unit and will meet the Fund's other acquisition and investment guidelines. Such acquisitions or investments may be financed by the issuance of Units or other securities, from the cash flows of the Fund or through borrowings. The Fund currently does not intend to reinvest the proceeds from any future monetization of the Allowed Secured Claim until the review process has been completed.

Future projects may be located in any region where opportunities meeting the Fund's objectives exist, although it is expected that these opportunities will exist primarily in Canada and the United States and may include: (i) district energy systems; (ii) natural gas-fired power plants; (iii) green energy projects (*i.e.*, biogas, biomass, waste-coal and wind); (iv) cogeneration projects; (v) energy outsourcing facilities that provide energy to wholesale, commercial, institutional and/or industrial customers; and (vi) energy infrastructure projects.

The Manager believes that investment opportunities for the Fund will arise: (i) as energy companies and financial sponsors seek to sell non-core assets; (ii) through consolidation in the energy industry; and (iii) through the right of first opportunity granted by the Manager to Countryside Canada and Countryside Holding to purchase any asset, entity or investment that would meet the investment criteria of Countryside Canada, Countryside Holding or the Fund (See "The Management and Administration Agreement - Management Agreement - Right of First Opportunity.)

Acquisition and Investment Guidelines

Subject to the conclusions reached in the strategic review process and rules promulgated under the Tax Fairness Plan, the following guidelines will be used in the review and evaluation of possible acquisitions and investments by the Fund:

- each asset will be acquired, or an investment made therein, only if the Fund believes that the acquisition or investment will result in accretive cash distributions per Unit;

- assets in respect of which long-term revenue and energy supply contracts with investment grade or financially stable counterparties exist will be preferred and, in other cases, free market electricity price and exchange rate assumptions used in the acquisition or investment evaluations will be obtained from a recognized independent source;

- the acquisition of, or investment in, each asset will be subject to prior due diligence and based on an independent engineer's report confirming the condition or development of the asset and the technical assumptions used in the acquisition or investment evaluation;

- the expected useful life of each asset and associated structures will, with regular maintenance and upkeep, conform with the Fund's objectives of providing long-term and stable cash distributions to Unitholders; and

- the acquisition of, or investment in, each asset will be reviewed and approved by the Trustees.

DESCRIPTION OF THE BUSINESS

General - Countryside Power Income Fund

The Fund was established to invest indirectly in energy and energy infrastructure projects. The Fund's indirect investments consist of the indirect ownership of the District

Energy Systems and indirect majority ownership of the California Cogen Facilities. The District Energy Systems have approximately 122MW of thermal and electric generation capacity, the California Cogen Facilities have approximately 94 MW (gross output) of electrical generation capacity and sold approximately 600,000 thousand pounds of steam in 2006 and, upon completion, the London Cogen Facility will have approximately 19 MW (gross output) of electrical generation capacity and is expected to sell 303,100 thousand pounds of steam annually. In addition, the Fund holds indirect investments in the Renewable Energy Projects located in the United States, which currently have approximately 52 MW of electrical generation capacity and sold approximately 660,000 MMBtus of boiler fuel in 2006. The Fund's investment in the Renewable Energy Projects consists of the USEB Allowed Claim with a current balance of approximately US$66 million in the USEB Chapter 11 proceeding.

The Independent Power Generation Industry

Overview

The traditional electricity market structure in North America has consisted of vertically-integrated utilities which had a near monopoly over the generation, transmission and distribution of electricity to retail customers. A variety of factors, including federal legislative changes, rapid growth in electricity demand, rising electricity rates, technological advances and environmental concerns, led certain governments to implement efforts to restructure the electricity industry within their respective jurisdictions. Such changes have, among other things, encouraged the development of generation from independent power producers. In the independent power generation sector, electricity is generated from a number of sources, including: (i) water; (ii) natural gas; (iii) coal; (iv) waste products, such as biomass and biogas; (v) geothermal sources, such as heat or steam; (vi) the sun; and (vii) wind.

While vertically integrated regulated utilities continue to dominate the North American electricity landscape, independent power producers are playing an increasingly important role in the supply of electricity. Policymakers have recognized the benefits of power generated by independent power producers, especially where such power is produced from renewable or waste resources, or at higher efficiencies than conventional utility-owned generation. A number of utilities and other non-independent power producers in the United States now offer customers the opportunity to purchase "green power" derived from renewable energy, which is priced at a premium to electricity generated from non-renewable sources.

Industry Regulation

United States

In the United States, the trend towards restructuring the electric power industry and the introduction of competition in electricity generation commenced with the passage and implementation of the *Public Utility Regulatory Policies Act* of 1978 ("PURPA"). Among other things, PURPA, as implemented by the United States Federal Energy Regulatory Commission ("FERC"), was enacted to encourage the development and operation of certain power generation facilities by requiring electric utilities to purchase power from qualifying facilities ("QFs") at the utility's avoided cost. A QF is a distinct type of energy producer that falls into one or both of two primary classes. One class of QFs are "small power production facilities" that generate power using specific energy sources such as wind, solar, geothermal, hydro, biomass or waste fuels, utilize a limited amount of fossil fuels and meet certain size criteria. Those of USEB's Renewable Energy Projects that produce power are in this first class because they are fueled by landfill gas and meet the relevant size criteria. A second class of QFs are "cogeneration facilities" which utilize fuel to produce both electric energy and useful thermal energy sequentially and meet certain operating and efficiency criteria. The Ripon and San Gabriel Facilities are in this second class since they produce electricity and steam and otherwise satisfy the applicable QF criteria. QFs are exempt from rate and other aspects of regulation by FERC under the *Federal Power Act*, exempt from all regulation by the Securities and Exchange Commission under the *Public Utility Holding Company Act of 1935* and exempt from regulation by State public service commissions with respect to rates and the financial and organizational activities of electric utilities. Prior to the enactment of the Energy Policy Act of 2005 ("EPA 2005"), a QF could not be primarily owned by one or more electric utilities or electric utility holding companies. Effective March 17, 2006, FERC amended its PURPA regulations and withdrew the exemption from FERC rate regulation for QFs with a power production capacity in excess of 20MW unless the QF sale is made pursuant to a power sales agreement on or before March 17, 2006 or the sale is made pursuant to a State regulatory authority's implementation of PURPA.

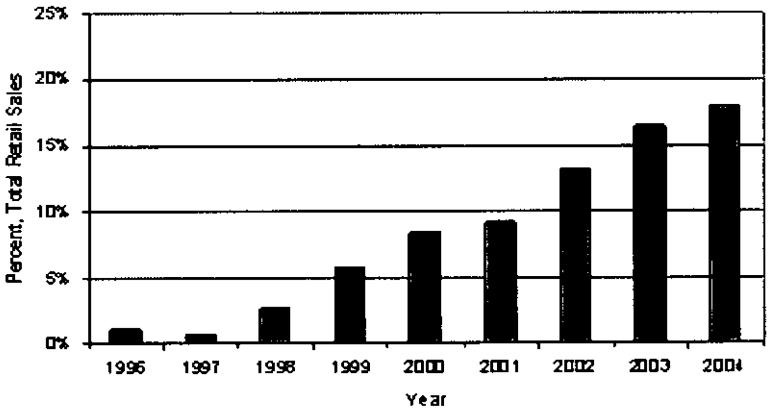
On August 8, 2005, comprehensive energy legislation was enacted when the President signed into law EPA 2005. That legislation makes several changes to PURPA, including: (1) eliminating the limitation on electric utility ownership of QFs, (2) terminating the mandatory purchase obligation imposed on electric utilities for new QFs that the FERC determines have access to competitive wholesale markets and (3) requiring the FERC to promulgate regulations no later than February 8, 2006 specifying additional criteria to be applied to new cogeneration facilities with respect to the useful thermal energy output of such facilities and to encourage the development of efficient generation technology. EPA 2005 makes clear that it does not apply to the rights and remedies of the parties to existing contracts or obligations in effect or pending before a State public service commission as of the date of enactment. Effective March 17, 2006, the FERC put into effect new regulations implementing the additional qualifying criteria to be applied to new cogeneration facilities and limiting the exemption from rate regulation by FERC available to QFs. Under the new regulations, the revised criteria for qualifying cogeneration facilities would not apply to the San Gabriel or Ripon Facilities since such projects were certified as ''qualifying facilities'' prior to the enactment of EPA 2005 and thus are not deemed to be "new cogeneration facilities." In addition, the limitation on the exemption from FERC rate regulation will not affect the Renewable Energy Projects or the San Gabriel or Ripon Facilities since all power produced by these Projects and Facilities is sold at rates established by a State regulatory agency's implementation of PURPA.

As noted above, the changes to PURPA made by EPA 2005 will not affect those Renewable Energy Projects that produce power or the Ripon and San Gabriel Facilities for so long as each such project continues to operate in compliance with the PURPA criteria applicable prior to the enactment of EPA 2005 and their PPAs remain in effect. In the event that any of such projects should lose QF status and if it should be determined that the purchasing utility has the right to terminate its PPA as a result thereof, it is possible that the changed criteria from the new legislation may be found to apply to any new PPA that such project would seek to enter into under PURPA. If such facility should temporarily lose QF status, the FERC could order the refund of amounts paid to the facility during the period of non-compliance. See ''Risk Factors — Qualifying Facility Status''.

With the exception of QFs, generation, transmission and distribution of electricity remained largely bundled until the enactment of the *Energy Policy Act of 1992* (the "1992 Act") and subsequent orders in 1996. Among other things, the 1992 Act enhanced FERC's power to open access to power transmission systems, contributing to significant growth in the independent power generation industry. On February 16, 2007, the FERC issued Order No. 890 and significantly modified its open access transmission policies and procedures to remedy opportunities for undue discrimination in the provision of wholesale transmission service.

While FERC regulates interstate power transmission and has a mandate to ensure that wholesale sellers have access to the transmission grid at fair and reasonable rates, retail competition is largely the responsibility of individual states. According to a November 2005 Energy Information Administration report, 19 states allow retail electricity competition. Electricity sales from these non-utility energy service providers ("ESPs") have been steadily increasing, accounting for 8% of national retail electricity sales in 2004, up from 0.6% in 1999. ESPs also provided 18% of all of the electricity sold in those 19 States (see graph below). Industrial and commercial end use customers of ESPs generally obtained lower average prices than customers choosing to remain with traditional bundled service in the deregulated states.

Market Share of Energy Only Providers in Deregulated States
1996 - 2004



Source: Energy Information Administration, Form EIA-861
"Annual Electric Power Industry Report."

California

When the California electricity market first permitted customer choice of generation supply, legislation fixed the retail rates of the three investor-owned utilities - Pacific Gas & Electric ("PG&E"), Southern California Edison ("SCE") and San Diego Gas and Electric (''SDG&E''). Originally, prices in the wholesale market were below the fixed level of retail rates; however, wholesale prices began to exceed the retail levels in the spring of 2000. The rise in wholesale prices was a result of a number of different factors including: (i) limited new generation capacity to accommodate demand growth; (ii) a wholesale market design that shifted significant amounts of wholesale electricity purchases to the spot market rather than to forward markets and which inhibited the utilities' ability to enter into long-term contracts;
(iii) historically low water levels in the Pacific Northwest combined with increased demand in regions that were traditionally significant exporters to the California electricity market; (iv) high natural gas prices; (v) lack of price signals to retail customers who were unaware of increased wholesale rates as a result of their fixed retail rates; and (vi) alleged market manipulation.

As a result of rising wholesale prices and limitations on increasing retail prices, PG&E and SCE reported financial difficulty in paying for power, including power from QFs, and reduced or stopped making various payments. In April 2001, PG&E filed for bankruptcy. Subsequently, PG&E and SCE resumed payments to QFs, entered into agreements with the California Public Utilities Commission (''CPUC'') intended to restore their financial positions and PG&E was discharged from bankruptcy in 2004.

In response to the developments described above, FERC, the California legislature and the CPUC enacted a number of measures significantly affecting the wholesale and retail electricity markets of California. While changes in the wholesale and retail electricity markets in California are expected to continue and may impact the degree of new generation supply entering the California market as well as future market price levels in unpredictable ways, the Fund expects that the impact on the Ripon or San Gabriel Facilities of such changes will be mitigated by their long-term capacity and energy sales agreements, under which capacity payments are largely fixed.

During periods when the full capacity of QFs are not committed to their respective counterparties, QFs may be subject to a ''must-offer'' obligation which FERC has required the California Independent System Operator (''CAISO'') to include in the ISO Tariff. In that event, CAISO can require QFs to sell power to the CAISO, if needed by the CAISO, provided that such sale would not violate a permit or cause loss of QF status and CAISO is required to compensate the QFs, pursuant to a rate formula set forth in CAISO's tariff on file with FERC. CAISO has proposed revisions to the ISO Tariff related to the must-offer obligation and the matter is pending before FERC.

Illinois

Regulatory restructuring of the electricity market in Illinois commenced in 1997 with the passage of *The Electric Service Customer Choice and Rate Relief Law of 1997*. As a result of this legislation and its subsequent amendments (the "Illinois Act"), the Illinois power market began a mandatory restructuring calling for "the first third" of commercial and industrial customers to have a choice for their generation supplier by October 1999, and with all customers – including residential – eligible to have their choice by January 2001. One of the associated amendments, titled Illinois Senate Bill 24, specifically promoted the use of cogeneration technology, and required Illinois' major utility, Commonwealth Edison ("ComEd"), to allocate $250 million towards special environmental initiatives and an energy-efficiency fund.

Customers were given the option of purchasing "bundled" power and energy from incumbent utilities at rates frozen until 2007, or to purchase power and energy on an "unbundled" basis by switching the generation component of their service to an "Alternative Retail Electric Supplier", or "ARES," or to an electric utility serving outside its traditional service area.

Although approximately 22% of ComEd's eligible customers had switched to alternative suppliers by the end of 2000, customers with other utilities initially showed little interest in the transition. By the end of 2004, however, ARES were serving a significant portion of Illinois' total electric consumption. This included about 23.5 million megawatt-hours (18.5% of total retail sales) to retail customers.

Some suppliers remain hesitant to serve the roughly 4.4 million eligible residential customers due to the high transaction costs associated with individual marketing relative to the associated profit. The Illinois government continues to encourage local participation, however, with passage of a law (83 Ill. Adm. Code 453) enabling electric suppliers to minimize these transaction costs by using their web sites to enroll customers.

With the end of the competitive retail transition period occurring January 1, 2007, there is reason to believe that customers will have further incentive to switch to alternative suppliers. On that date, the rate freeze on unbundled retail rates expires reverting to wholesale prices, allowing ARES to better compete against market rates.

<u>Canada</u>

Provincial governments have legislative authority over the generation, transmission and distribution of electricity in Canada. The movement toward restructuring the Canadian electricity industry has been similar to that of the U.S., as each province has determined its policy in this area based on its own assessment of its unique regional circumstances and issues.

Ontario

In 1987, Ontario Hydro, with the support of the Ontario Ministry of Energy, developed policies to encourage the addition of new generating capacity by independent power producers. In connection with this policy initiative, Ontario Hydro entered into a number of long-term PPAs with independent power producers. As of December 31, 2000, there were approximately 90 facilities owned and operated by independent power producers in Ontario that generated a total of 10,710 GWh of power in 2000 from a variety of energy sources, such as water, natural gas and biomass.

On April 1, 1999, Ontario's electricity industry was substantially restructured with the division of Ontario Hydro into five separate corporations, the three main companies being Ontario Power Generation Inc. ("OPG"), the successor to Ontario Hydro's generation business, Hydro One Inc., the successor to Ontario Hydro's transmission and distribution business and the Independent Market Operator (now the "Independent Electricity System Operator" or "IESO"), successor to Ontario Hydro's system control function.

On May 1, 2002, Ontario's electricity market opened to competition at both the wholesale and retail levels. With market opening, Ontario generators, wholesalers and suppliers began selling electricity to and buying from a real time energy or spot market administered by the IESO. Wholesale and retail consumers were also permitted to select the electricity supplier of choice.

In December 2002, in response to increased prices of electricity, the provincial government passed the *Electricity Pricing, Conservation and Supply Act, 2002* that fixed the price of electricity for low volume and designated consumers at 4.3 cents/kWh and capped electricity distribution fees and wholesale market charges.

On December 18, 2003, the newly-elected Liberal government enacted the *Ontario Energy Board Amendment Act, 2003* changing the electricity prices for residential and certain other designated consumers (municipalities, universities, colleges, schools, hospitals, farms and customers whose annual electricity usage is 250,000 kWh or less) effective April 1, 2004 to 4.7 cents/kWh for the first 750 kWh consumed in any month and 5.5 cents/kWh for any consumption above that level. Customers other than low volume and designated consumers would remain subject to market pricing. The legislation also required that the Ontario Energy Board ("OEB") establish any new electricity prices for these consumers.

On December 9, 2004, the provincial government enacted the *Electricity Restructuring Act, 2004*, which provided for following additional changes to the Ontario electricity sector:

- creating the Ontario Power Authority ("OPA") with responsibility for ensuring adequate, long-term supply of electricity and integrated system planning;
- revising the role of the IESO;
- establishing a framework for setting prices for OPG's base load nuclear and large hydro-electric assets ("OPG's regulated assets") and prices for its non-regulated assets;
- creating a Conservation Bureau, led by a Chief Energy Conservation Officer;
- enabling the Minister of Energy to set targets for conservation, renewable energy and the overall supply mix within Ontario.

In February of 2005, the Ontario government set an average price of 4.5 cents/kWh on the output of OPG's regulated assets for the period between April 1, 2005, to no later than March 31, 2008, at which point the OEB is to become responsible for setting the prices. The government also established a revenue limit of 4.7 cents/kWh on OPG's unregulated generation assets for between April 1, 2005 and no later than April 30, 2006 with any revenues obtained in excess of the 4.7 cents being rebated to consumers in April 2006. In February 2006, the government announced a further extension of the revenue limit to April 30, 2009, at 4.6 cents/kWh from May 1, 2006 to April 30, 2007, 4.7 cents/kWh from May 1, 2007 to April 30, 2008 and 4.8 cents/kWh from May 1, 2008 to April 30, 2009. The government also provided that any revenues above the limits would be rebated to consumers quarterly. The pricing described immediately above principally affects large industrial and commercial customers. In 2006 the OEB also commenced the process of establishing the prices for output from OPG's regulated assets.

In March of 2005, the OEB announced changes to the electricity prices for residential and other designated consumers starting April 1, 2005 to 5.0 cents/kWh on the first 750 kWh consumed in any month and 5.8 cents/kWh for any consumption about that level (the "Regulated Price Plan" or "RPP"). The OEB indicated that the RPP would be based upon forecast electricity prices in the spot market, OPG's regulated asset prices and existing contract prices for supply from independent power producers. The OEB would track in a variance account the difference between the amount consumers paid for electricity and the amount that was paid to generators. Consumers who leave the RPP would be required to settle their share of the balance of that variance account. The OEB also indicated that commencing in November of 2005 the price threshold would change twice a year (first 1,000 kWh/month during the winter months and 600 kWh/month during the summer months), but this pricing (subject to the revised threshold) would remain in place until the spring of 2006.

In April 2006 the OEB announced new electricity prices for the RPP consumers effective May 1, 2006 and a further change to those prices in November 1, 2006. As of November 1, 2006 prices were 5.5 cents/kWh up to a certain threshold per month and 6.4 cents/kWh for consumption above that threshold. For residential consumers the monthly threshold was set at 1,000 kWh per month from November to April and 600 kWh per month during May to October period. For other designated consumers the threshold was fixed at 750 kWh for the entire year.

Since the provincial election of September 2003, the Ontario government, and subsequently the OPA under Ministerial directive has conducted a number of Requests for Proposals for new generation supply – both conventional (typically natural gas) and renewable. In 2006 the OPA commenced its development of an Integrated Power System Plan ("IPSP"). The IPSP is a comprehensive pan which identifies conservation, generation and transmission investments needed in Ontario in the next three to five years while looking forward on a twenty year horizon. It is expected that the OPA will submit the IPSP to the OEB for review and approval during 2007. With IPSP approval, the OPA will be permitted to procure generation without the need for Ministerial directive.

It is anticipated that further RFPs will be commenced in 2007. The OPA with the assistance of the OEB also launched in 2006 a Standard Offer Program for small renewable generation projects of less than 10 MW.

The need for a large amount of new generation supply in Ontario is due in large part to the government's determination to close its coal-fired generation facilities by 2009. In 2006, the government recognized that it would be unable to close down all of the coal fired generation by 2009 but reaffirmed its commitment to their closure at the earliest possible time without compromising reliability. The closure of the last coal fired generating unit is now expected to occur sometime in 2014.

The District Energy Industry

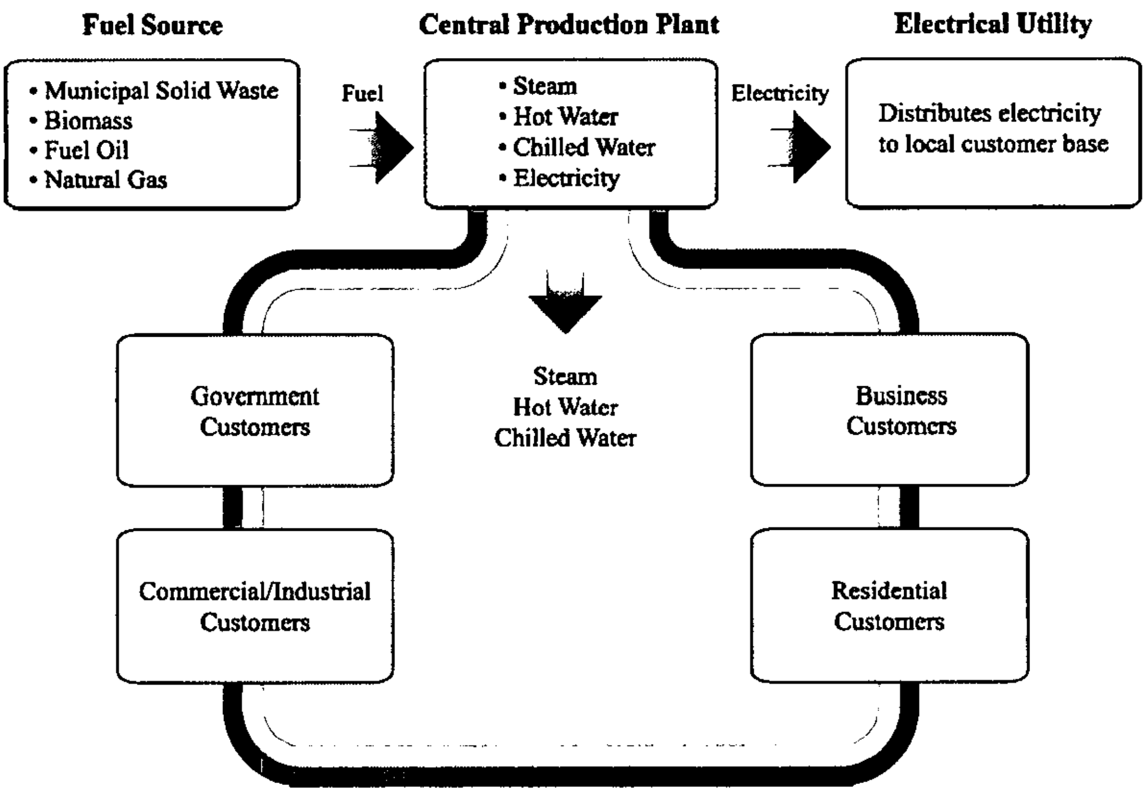
Overview

District energy systems are common in large urban centers worldwide and in North America, including Toronto, Montreal, New York, Philadelphia and Boston. Over 5,000 district energy systems are currently in operation in the U.S., supplying over 8% of commercial floor space. District energy systems typically consist of one or more central production plants that generate steam, hot water and/or chilled water and distribute it through underground pipes to customer buildings.

Structure of District Energy Systems

The central production plant of a typical district energy system converts fuel, such as natural gas, biomass, fuel oil or coal, into steam, hot water and/or chilled water which is distributed through underground pipes to its customers to provide heating, air conditioning and some industrial process uses. Customers typically include government offices, hospitals, educational institutions and apartment buildings, as well as commercial businesses that commonly outsource for such services.

TYPICAL DISTRICT ENERGY SYSTEM



Outlook for the District Energy Industry

Argonne National Laboratory and the International District Energy Association estimate that district energy could provide up to 30% of the thermal energy needs in the United States by 2010. New and expanded markets include urban areas, universities and colleges, military installations, and other campus or institutional settings. This growth is driven by the benefits it can provide to local economies, including the revitalization of urban centers by providing a reliable, low-cost energy infrastructure and improving air quality.

Rising energy costs for industrial and commercial consumers, coupled with new environmental initiatives, have encouraged the expansion of existing systems and the development of new systems in Canada. District energy systems have been introduced over the last five years in cities such as Windsor, Sudbury and Markham.

Advantages of District Energy Systems

High Customer Retention

District energy systems provide customers with an attractive alternative to conventional in-house heating and cooling systems. Contracting for energy services with a district energy system eliminates the requirement of a customer to provide building space to house boilers, human resources to manage its systems, and the associated capital investment. In addition, the pricing structure of district energy sales is such that the cost to a customer is competitive with alternative services, resulting in high customer retention.

High System Reliability

District energy systems have been designed to achieve higher reliability than conventional in-house systems as a result of the greater system management expertise and the incorporation of multiple back-up systems, which is not typically feasible to implement in smaller installations.

Low Operating Costs

The operation of large, efficient boilers and integrated distribution systems provides for low operating and maintenance costs on a per customer basis. In addition, district energy systems can be designed to utilize inexpensive, readily-available, low-grade fuels, such as biomass, to enhance operating margins. The use of cogeneration further reduces operating costs by simultaneously producing thermal energy and electricity.

Premium Pricing for Value Added Service

District energy competes in the marketplace with a customer's alternative sources of heating and cooling, and is typically valued at a premium based on its superior convenience, reliability and environmental advantages.

The Cogeneration Industry - United States

As a general rule, power generating facilities produce heat in the process of creating electricity. Historically, conventional power plants released this heat into the environment. The Public Utility Regulatory Policies Act (PURPA) discussed above encourages renewable and alternative energy sources as a substitute to petroleum and foreign-based energy requirements, and creates a special market for power generating facilities which capture this excess heat, and divert it to domestic or industrial heating purposes. This has resulted in an increased ratio of energy-produced to energy-consumed, thereby enhancing resource efficiency and reducing dependency on external energy requirements.

Power producing facilities that can show relative efficiency to conventional power generating assets through a secondary use of the energy created from a given fuel input can earn special entitlements. If the combination of electricity output plus thermal heat employed meet certain efficiency or other operating or environmental standards, these "cogenerators" can earn the designation of "Qualifying Facility", or "QF". QF status can prove lucrative as electricity produced by these facilities is, under certain circumstances, required to be purchased by utilities under long-term contract at prices and quantities set by the State. Congress thus has effectively ensured that these cogenerators have a guaranteed market for their power at a price equal to the utilities avoided cost of traditional (typically fossil fuel) power generation. While EPA 2005 has conditioned the benefits afforded to QF's under PURPA in certain respects, existing QF's including the Ripon and San Gabriel Facilities should not be subject to such conditions so long as they continue to sell power pursuant to their existing PPA's. See "Description of the Business - The Independent Power Generation Industry - Industry Regulation - United States".

Outlook for the California Power Market

The Manager believes California's combination of increasing demand for electricity, ageing assets (and future retirements) and slow construction of new facilities creates an environment conducive to the Ripon and San Gabriel Facilities' ongoing operational and economic viability beyond expiration of their PPAs.

Fueled primarily by a strong economy and population growth, demand for electricity in California has steadily increased, outpacing growth in supply. California's electricity rates remain among the highest in the United States and, according to the California Energy Commission (the "CEC"), wholesale electricity prices increased from an average of $20 per megawatt hour (MWh) in 2001 to approximately $50 per MWh today[1].

From 2001 to 2004, California's electricity consumption increased by almost 3% per anunum, exceeding CEC's own forecasts. Consumption is expected to continue to increase at a rate of 1.2% to 1.5% annually through 2016 as a result of population and commercial growth[2]. More critical to achieving quotidian supply is meeting peak demand – a major concern for utilities as they require sufficient supply to meet customer loads during short periods but also because this demand stresses ageing transmission infrastructure threatening system overloads. Peak demand is expected to increase at an even higher rate than average consumption (1.4% to 1.75% over the same period)[3]. The

(1) Source: California Energy Commission 2005 Integrated Energy Policy Report

(2) Ibid.

(3) Source: California Energy Commission. California Energy Demand 2006-2016. Staff Energy Forecast. revised September 2005.

result is a strong reliance on California's existing generating projects as well as development and refurbishment of assets for future supply.

If the past is any predictor of the future, however, California may continue to face critical shortages in electricity. Electricity supply has not kept up with demand primarily for two reasons. First, there is a lack of permitted power plants moving into construction since these projects lack the Power Purchase Agreements necessary to secure their financing. In fact, out of the 22,386 MW approved for construction since 1998, only 13,805 MW, or 62%, have come online[(4)]. Second, procurement has focused on the near-term rather than long-term. Even with strong political support and policy implementation to supplement existing generation with a diversified portfolio of alternative energy resources, the transition from electricity produced by natural gas to other renewable fuels has been slow.

Adding further concern is the ratio of "high risk" power plant retirements relative to planned capacity additions. Between 2005 and 2008, expected retirements total 7,955 MW versus planned additions of 4,106 MW[(5)]. To mitigate this shortfall, the CEC is encouraging utilities to reward modern, clean and efficient projects with longer term power contracts.

According to the CEC, "by 2016, California's utilities will need to procure approximately 24,000 MW of peak resources to replace expiring contracts and retiring power plants and meet peak demand growth"[(6)]. Expansion opportunities exist for plants with existing PPAs and readily available capital. In its 2005 Integrated Energy Policy Report, the CEC states, "It is critical that there are enough long-term commitments *to bring new generation on line and re-power existing aging power plants*. This is necessary both to meet future reliability needs and ensure moderate prices [emphasis added]"[(7)].

Thus the Manager believes that the Ripon and San Gabriel assets remain well situated to capitalize on California's current electricity market condition.

(4) California Energy Commission, 2005 Database of California Power Plants.

(5) Source: California Energy Commission, Revised California and Western Electricity Outlook Report, July 2005.

(6) Ibid.

(7) P. 62.

The Biogas Industry

Overview

Biogas, also known as landfill gas, is generated from the decomposition of organic or carbon-based materials, including municipal solid waste. Biogas consists mainly of methane and carbon dioxide, roughly in equal proportions. Methane gas may be used for electrical power generation and for industrial applications. Electricity and boiler fuel sales from renewable energy projects are dependent upon the rate, quantity and quality of gas flow and the effectiveness of the biogas collection systems on a landfill site.

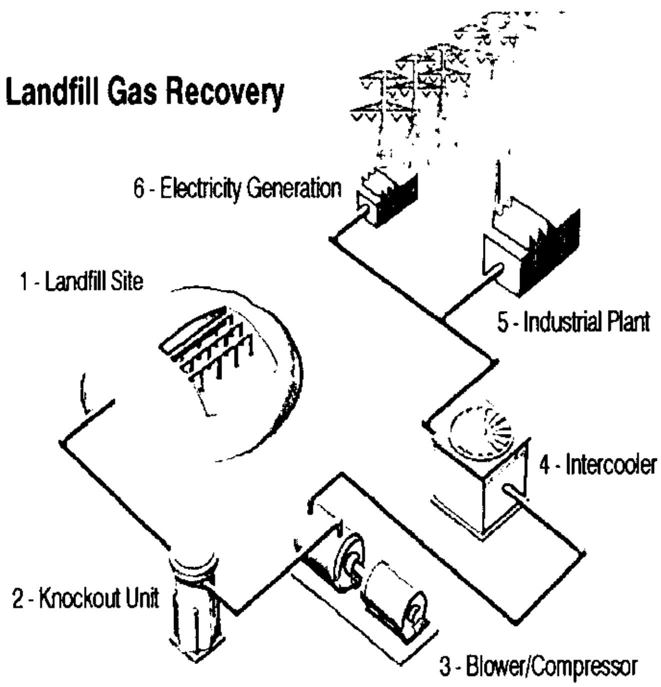
Biogas is collected by installing gas wells into a landfill at predetermined separations. The wells are connected by a series of pipes that deliver the biogas to the processing and conversion stations. The entire piping system is under a partial vacuum causing biogas in the landfill to migrate toward the wells. Once the biogas is collected, it is delivered to a central processing facility where it is filtered to remove any contaminants that may be suspended in the biogas stream. It is then utilized as fuel to generate electricity, transported to a third party, or flared.

Biogas production at a landfill is estimated using models developed in association with the EPA and other similar bodies. Production estimates are based on accepted, theoretical decay patterns of carbon-based materials, with inputs that include: the filling pattern of the landfill, the composition of the waste, compaction, moisture content, time and local weather conditions. As the amount of waste deposited into a landfill increases, the amount of potential biogas that can be generated by the decomposition of waste also increases. Biogas generation peaks shortly after the closure of the landfill and starts to decline as the ratio of decomposed waste to under-composed waste increases. According to the EPA, depending on the size of the landfill and the amount of waste deposited into the landfill, the amount of biogas generated should continue to be substantial enough to support commercial operations for 20 to 30 years after a landfill ceases to accept waste.

Both methane and carbon dioxide are considered greenhouse gases and contribute to global warming. However, methane is significantly more damaging to the environment than carbon dioxide. The EPA first began regulating municipal solid waste landfills and biogas in 1991 under the *Resource Conservation and Recovery Act*. In 1996, the EPA released the Clean Air Act New Performance Standards and the associated emissions guidelines. As part of these guidelines, newer landfill facilities with large design capacities are required to install gas collection and control systems. The EPA also requires older landfills that exceed prescribed fill amounts to install gas collection and management systems.

The following diagram illustrates a typical biogas collection and electricity generation process.

Biogas Collection and Power Generation Process



1. **Landfill Site:** Biogas recovery is suitable for existing as well as future landfill sites. In existing sites, the biogas is collected by installing vertical wells every 150 to 300 feet and connecting these vertical wells to a central processing station.
2. **Knockout Unit:** A knockout unit is used to screen out contaminants and free liquids suspended in the biogas.
3. **Blower/Compressor:** The blower/compressor is used to create a partial vacuum in the system that causes the biogas to migrate through the wells toward the processing station.
4. **Intercooler:** The intercooler is used to reduce the temperature of the biogas allowing residual moisture to condense.
5. **Industrial Plant:** At this point, the biogas may be sold as boiler fuel directly to an end-user such as an industrial plant.
6. **Electricity Generation:** Alternatively, it may be used to power generators that convert it into electricity for sale to the local electric utility.

Government Support for Renewable Energy Projects

The U.S. federal government and a number of state governments have put programs in place that provide biogas owners with tax credits, emission credits and/or premium rates for the sale of electricity.

<u>*Section 29 Tax Credits*</u>

A significant incentive introduced by the U.S. federal government relating to biogas has been the Section 29 tax credit. "Section 29" refers to a program that forms a specific part of federal tax law known as the *Crude Oil Windfall Profit Tax Act of 1980*. This program introduced federal tax credits which are generated upon the sale of certain types of alternative fuels, including the methane component of biogas. The tax credit is generated when the owner of a biogas collection facility sells a unit of methane to an unrelated party for use in energy production. The buyer of the methane is considered to be unrelated to the owner of the biogas facility under this legislation if there is no more than 50% overlapping ownership, either directly or indirectly, between the two. For credits claimed in 2004, each MMBtu of biogas sold for the generation of energy produced a tax credit of approximately US$1.13 Tax credits for projects developed after 1992 that were operational prior to July 1, 1998 will expire on December 31, 2007.

Through December 31, 2007, Section 29 has a phase out provision that is triggered when the ''Market Wellhead Price'' of domestic crude oil reaches certain ''Phase-out Prices'' as determined by the IRS. The phase-out is proportional. The Market Wellhead Price is the IRS' estimate of the calendar year average wellhead price per barrel for all domestic crude oil, the price of which is not subject to regulation. Phase out Prices are adjusted each year for inflation.

To qualify for Section 29 tax credits, a biogas facility must have been placed in service before July 1, 1998, pursuant to a binding written contract entered into before January 1, 1997. A contract was binding if it provided a completion date, a maximum price, was valid under state law, did not limit damages to a specified amount (or provided for liquidated damages of at least 5% of the total cost of the facility), and was not substantially modified on or after January 1, 1997. The facility was placed in service before July 1, 1998 if, by that date, the owner of the facility obtained all necessary licenses and permits, completed all critical testing of the facility, and controlled the facility, and if the facility was capable of producing biogas for sale and commenced daily operation, even if further testing to eliminate defects occurred later.

Illinois Incentives

The State of Illinois, in an effort to encourage the development of green energy fuels, among other things, initiated an incentive program to promote the development of renewable energy projects. The first step in this process was accomplished by classifying a renewable energy project that meets certain requirements as a "Qualified Solid Waste Energy Facility" or "QSWEF" under the *Local Solid Waste Disposal Act*. A QSWEF benefits from the provisions of the *Illinois Public Utilities Act* and the *Purchase and Sale of Electric Energy from Qualified Solid Waste Energy Facilities* of the *Illinois Administrative Code*. These state mandates, as implemented by the Illinois Commerce Commission ("ICC"), require an electric utility to enter into a PPA with a QSWEF that has a minimum term of 10 years so long as, among other things, no entity that directly or indirectly owns more than 50% of such QSWEF is primarily engaged in the business of producing or selling electricity, gas or useful thermal energy from a source other than one or more QSWEFs. The electric utility is obligated to purchase the electricity generated by a QSWEF located in such utility's service area at a rate that is equal to the average amount per kWh paid by the local government entities (with certain exceptions) for electricity in such QSWEF's jurisdiction (the "Gross Contract Rate"). The Gross Contract Rate typically exceeds the purchasing utility's Avoided Cost. In such case, the QSWEF receives a premium for the sale of its electricity to the utility, in the form of an incentive, which represents the excess of the utility's Gross Contract Rate over its Avoided Cost. To recover the cost of this incentive, the utility is entitled to Illinois State tax credits equal to the amount of the incentive paid to the QSWEF.

The QSWEF is obligated to reimburse the State of Illinois for the amount of the tax credits claimed by the utility to which it sells electricity and is required to begin repaying this amount no later than the earlier of the date it has paid or otherwise satisfied in full the capital costs or indebtedness incurred in developing the project and 10 years from the date the project began commercial operation. Pursuant to regulations under the *Illinois Public Utilities Act* (the "ICC Regulations"), all incentives must be fully repaid by the QSWEF upon the earlier of 20 years after it began commercial operation or the end of its actual useful life. The incentives are to be repaid over the required repayment period pursuant to a schedule to be determined by the ICC based on the manner in which the utility claimed the tax credits.

In addition, each month, a QSWEF is required to pay the Illinois Department of Revenue an amount equal to US 0.06 cents/kWh sold by it during the prior month. The State of Illinois terminated this incentive program in 2006 but USEB's Illinois-based projects were grandfathered.

On March 22, USEY announced that USEB reached an agreement in principle with the State of Illinois resolving outstanding issues between the parties in the bankruptcy proceedings. According to USEY, among other things, the State of Illinois has agreed not to pursue repayment of approximately US$63 million in incentives in return for a payment of US$5.3 million on the effective date of USEB's plan of reorganization (which has not yet been filed) and no later than May 31, 2007. In addition according to USEY's announcement, USEB's Illinois-based projects will withdraw from the Illinois retail rate incentive program effective May 31, 2007. Such agreement is subject to the approval of the Bankruptcy Court.

Other State and Local Incentives

A number of states provide incentives to encourage the development of biogas and other green energy fuels. These incentives have taken the form of direct incentives, renewable energy purchase requirements ("Renewable Portfolio Standards") and the establishment of renewable energy funds. The table below summarizes those U.S. states with Renewable Portfolio Standards.

SELECTED GREEN ENERGY INCENTIVES BY STATE

State	Renewable Portfolio Standards — Minimum % from Green Fuels[1]	Biogas Included
Arizona	15% by 2005	Yes
California	20% by 2017	Yes
Colorado	10% by 2015	Yes
Connecticut	10% by 2010	Yes
District of Columbia	11% by 2022	Yes

State	Renewable Portfolio Standards — Minimum % from Green Fuels[1]	Biogas Included
Hawaii	20% by 2020	Yes
Illinois	25% by 2017	Under Review
Iowa	105MW	Under Review
Maine	10% by 2017	Yes
Maryland	7.5% by 2019	Yes
Massachusetts	4% by 2009	Yes
Minnesota	25% by 2025	Under Review
Nevada	20% by 2015	Yes
New Jersey	6.5% by 2008	Yes
New Mexico	20% by 2020	Yes
New York	24% by 2013	Yes
Pennsylvania	18% by 2020	Yes
Rhode Island	15% by 2020	Yes
Texas	5,880MW by 2015	Yes
Wisconsin	2.2% by 2011	Yes

(1) Source: Database of State Incentives for Renewable Energy, Interstate Renewable Energy Council, and U.S. Department of Energy, 2005 and 2006.

(2) New York State entities are mandated to purchase electricity produced from renewable fuels.

Advantages of Renewable Energy Projects

Abundant and Low Cost Fuel Source

Containment and consolidation of solid waste into landfill sites is a common practice worldwide. The low cost to extract biogas from landfills makes it attractive for power generation relative to natural gas or other more conventional fossil fuel sources.

Environmental Benefits

Biogas produced by landfills has been described as one of the largest contributors to global warming. In order to comply with environmental regulations and reduce the hazard arising from a build-up of biogas (which is highly combustible), landfills are required to burn or flare it in a controlled manner. Converting biogas into electricity not only achieves these objectives, but also provides an alternative source of energy.

Government Support

The recent growth in the development of renewable energy projects is partly a result of the support that biogas and other green energy fuels are receiving from federal and state governments, regulators and customers in the form of (i) tax credits; (ii) emissions credits; and/or (iii) premium rates for the sale of electricity.

Premium Pricing for Green Energy

Excluding incentives received from federal and state governments, power generated using green energy fuels, such as biogas, has, in certain instances, been able to obtain a premium price over power generated from conventional sources due to the introduction of Renewable Portfolio Standards and increased environmental awareness.

Proven Technology

Several types of standardized equipment are used to generate electricity from biogas. The power generation equipment is manufactured by companies such as GE/Jenbacher, Caterpillar and Deutz all of whom have established track records in the power generation industry. The most common equipment types are reciprocating engines or internal combustion engines, which are customized to operate on biogas. According to the EPA, 82% of renewable energy projects that generate electricity utilize this technology. For sites with high gas flow, steam turbines or gas turbines may be used.

Low Operating Costs

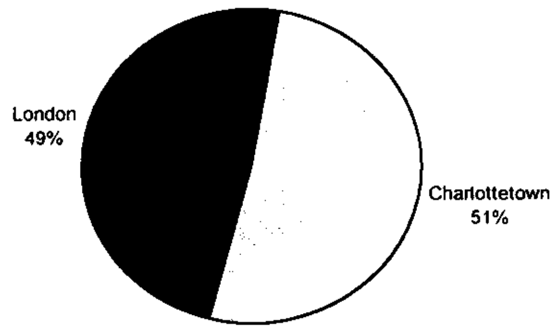
As a result of the low maintenance requirements and high reliability of biogas equipment, operating expenses for renewable energy projects are comparatively stable and predictable.

THE DISTRICT ENERGY SYSTEMS

Overview

The District Energy Systems are located in Canada, one in Charlottetown, PEI and one in London, Ontario, and have approximately 122MW of thermal and electric generation capacity. The following chart summarizes the District Energy Systems' thermal and electric capacity.

SUMMARY OF DISTRICT ENERGY SYSTEMS THERMAL AND ELECTRIC CAPACITY (MW)



The PEI District Energy System produces steam, hot water and electricity using biomass, waste fuel and fuel oil. The London District Energy System produces steam, chilled water and electricity using natural gas as its primary fuel and fuel oil as its alternative fuel. The steam, hot water and/or chilled water generated by the production facilities are distributed to government, commercial and residential customers through underground distribution systems. The high credit quality and long-term contracts with the systems' largest customers, in conjunction with the long-term relationships with its other customers afford stability and predictability to the cash flows of each system. In 2003, a review of the District Energy Systems was conducted by an independent consultant, which included reviews and analyses of equipment, performance and environmental matters.

DISTRICT ENERGY SYSTEMS SUMMARY

System	Province	MW	Top Five Customers[1]	Purchase Agreement Expiry	Customer S&P Credit Rating
Charlottetown	PEI	62.5	Department of Transportation and Public Works	2025	A[2]
			Queen Elizabeth Hospital	2025	Government Funded[2]
			University of Prince Edward Island	2025	Government Funded[2]
			RioCan Property Services	2011	BBB[3]
			Charlottetown Area Development Corp.	2009	Government Funded[2]
London	ON	59.6	London Health Sciences Centre	2011	Government Funded[2]
			London Hospital Linen Service	2021	Government Funded[2]
			City Centre (Osmington Inc.)	2013	Not Rated
			London Free Press (Sun Media Corporation)	2008	(BB-)
			Royal Host Hotels (Hilton)	2021	(BBB-)
Total		**122.1**			

(1) The top five customers of the PEI District Energy System represented approximately 71.03% of 2006 revenues of the PEI District Energy System. The top five customers of the London District Energy System represented approximately 48.0 % of 2006 revenues of the London System.

(2) Government funded customers receive substantial direct and/or indirect support of one of, or a combination of, the federal, provincial or municipal governments. The S&P credit ratings for Canada and the Provinces of PEI and Ontario are "AAA", "A" and "AA", respectively.

(3) DBRS senior unsecured debenture rating for RioCan Real Estate Investment Trust.

The PEI District Energy System

The PEI District Energy System is a district energy system located in Charlottetown, PEI with total distributing capacity of approximately 72MW and total electricity generating capacity of 1.2MW. The PEI District Energy System initially consisted of three separate systems, which were built from 1983 through 1987: the Queen Elizabeth Hospital, the Prince Edward Home and the University of Prince Edward Island systems. In 1995, the systems were upgraded and the distribution lines connected to improve efficiency and provide an integrated base for further expansion.

The PEI District Energy System produces energy in the form of steam, hot water and electricity from three production facilities. The system is fueled primarily by biomass and waste fuel while fuel oil is used for peaking and back-up. The distribution systems consist of 17 km of hot water distribution and 1.5 km of steam distribution.

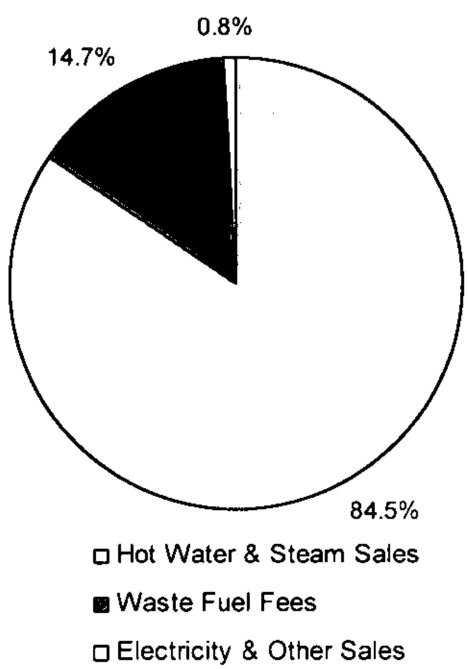
Steam, Hot Water and Electricity Sales

The PEI District Energy System sells steam and hot water to customers in over 100 governments, commercial and residential buildings, each of which is connected to its distribution system. The system's major customers include the Department of Transportation & Public Works, the Queen Elizabeth Hospital and the University of Prince Edward Island, each of which is under long-term contract. Contracts with the system's largest customers generally provide for the pass-through of fuel costs, thereby mitigating the impact of energy price and weather volatility. Approximately 76% of the system's revenues were generated from government-funded entities or investment grade customers in 2006. The system sells the electricity generated beyond that required for the system's operations to Maritime Electric Company, Limited.

Rates for small customers are adjusted monthly, and are based on the customer's cost of fuel oil (the alternative fuel source for heating in PEI), thus enabling prices to remain competitive to other customer alternatives.

In addition to steam, hot water and electricity sales, the system generates revenue from waste fuel fees associated with its acceptance of municipal solid waste from Island Waste Management Corp. ("IWMC"), a Canadian crown corporation run by the Department of Transportation and Public Works.

REVENUE BREAKDOWN BY SOURCE
YEAR ENDED DECEMBER 31, 2006



Customers

The PEI **District Energy** System's 10 largest customers as measured by 2006 revenue are listed in the following table.

Customers	Customer S&P Credit Rating	Purchase Agreement Expiry	% of 2006 Revenue
Department of Transportation & Public Works			
Steam Sales	A[2]	2025	19.6%
Fuel Fees[1]	A[2]	2025	13.8%
Queen Elizabeth Hospital	Government Funded[2]	2025	18.9%
University of Prince Edward Island	Government Funded[2]	2025	15.4%
RioCan Property Services	BBB[3]	2011[4][5]	3.1%
Sport PEI	Government Funded[2]	N/A[2]	1.9%
Charlottetown Area Development Corp.	Government Funded[2]	2009	1.7%
Dyne Holdings	N/A	N/A[2]	1.5%
Charlottetown Hotel	N/A	N/A[4]	1.4%
Confederation Center	Government Funded(2)	2009	1.3%
Holland College		2014	1.3%
Total			**80.1%**

(1) Fuel Fees are generated from IWMC.

(2) Government-funded customers receive substantial direct and/or indirect support of one of, or a combination of, the federal, provincial or municipal governments. The S&P credit ratings for Canada and PEI are "AAA" and "A" respectively.

(3) DBRS senior unsecured debenture rating for RioCan Real Estate Investment Trust.

(4) Customers without indicated contract expiries are customers-at-will. For most customers however, a long demonstrated payment history based on the terms of the original contract exists.

(5) The customer's building has been connected to the PEI District Energy System since 1989. The term of the agreement is indefinite, but can be terminated by either party with one month's notice.

Energy Generation

The PEI District Energy System generates steam and hot water from three plants: the Energy from Waste Plant (the "EFWP Facility"), the University of Prince Edward Island Facility (the "UPEI Facility") and the Prince Edward Home Facility (the "PEH Facility"). The EFWP Facility is the largest of the three plants and provides the base load for the system. Total capacity is 193,100 lbs/hour of steam, generated from waste fuel, biomass and fuel oil. The UPEI Facility is the main back-up to the EFWP Facility, providing peak firing using fuel oil. In addition, this facility provides cooling to several buildings on the university campus through two chillers supplied with hot water from the distribution system. The PEH Facility, the original district energy facility, is seldom utilized, but can be fired using fuel oil.

In 2003, Countryside District Energy upgraded the EFWP Facility with the installation of two new economizers, upgrades to the wood-fired systems and the installation of a new thermal storage tank. These upgrades were designed to enhance the use of more economic biomass fuels and reduce the use of more expensive fuel oil.

Plant	Capacity	Equipment	Fuel Supply
EFWP Facility (base load facility)	153,100 lb/hour (44MW)	• Three energy-from-waste units and one heat recovery steam generator • Two wood-fired boiler systems • Three fuel oil-fired boilers • 35 MWh (550,000 gal) storage tank	• Municipal solid waste (primary) • Wood waste (primary) • Fuel oil (backup)
UPEI Facility (back-up and peaking facility)	64,000 lb/hour (18MW)	• Three firetube boilers •	• Fuel oil
PEH Facility (back-up and peaking facility)	19,000 lb/hour (5.5MW)	• Three boilers	• Fuel oil

Fuel Supply

The PEI District Energy System's three production facilities are fuelled by wood waste (biomass), municipal solid waste and fuel oil for supplementary firing and for peak periods, representing approximately 41.0%, 40.0% and 19.0% of 2006 fuel volume, respectively. The system has contracted for the supply of wood waste through an agreement that expires in 2025 with Georgetown Timber Ltd., a sawmill in PEI. The system receives municipal solid waste from IWMC.

Employees, Operations and Maintenance

There are 30 full-time employees currently employed at the PEI District Energy System. The employees are non-unionized, and the system has never experienced a work stoppage. The PEH Facility and the UPEI Facility are operated under long-term leases with the provincial government and the university, respectively. All other land and equipment is owned directly by the PEI District Energy System.

Environmental

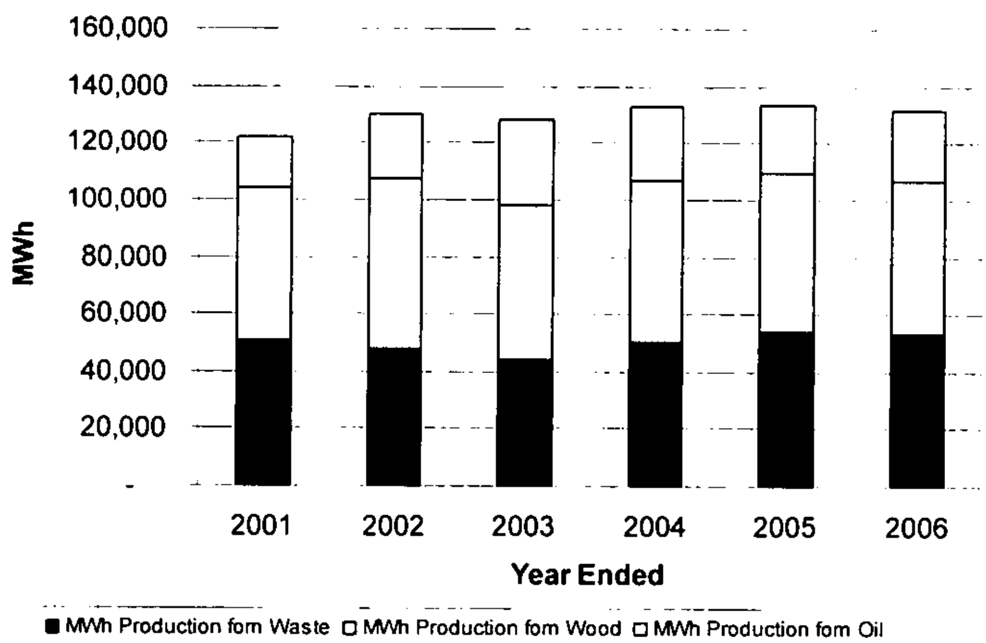
The PEI District Energy System is in material compliance with environmental laws, and has not received any notices or citations relating to environmental compliance. The PEI District Energy System is required to report its emissions and operating data to the provincial Department of Environment on an annual basis under its operating permit. In addition, there is a federal requirement to report emissions data annually under the

National Pollutant Release Inventory program. Any costs of environmentally driven upgrades required as a result of changes in environmental laws are the direct responsibility of the provincial government.

Operating History

Energy production has increased since 1998, with the largest increase between 2001 and 2002. Waste energy as a percentage of total production declined somewhat over the past few years prior to 2004 due to an increase in overall sales as well as a marginal drop in waste volumes due to the implementation of an integrated waste management system in PEI. Waste Energy as a percentage of total production increased somewhat in 2004 as a percentage of total production has remained constant.

PEI DISTRICT ENERGY SYSTEM ENERGY PRODUCTION



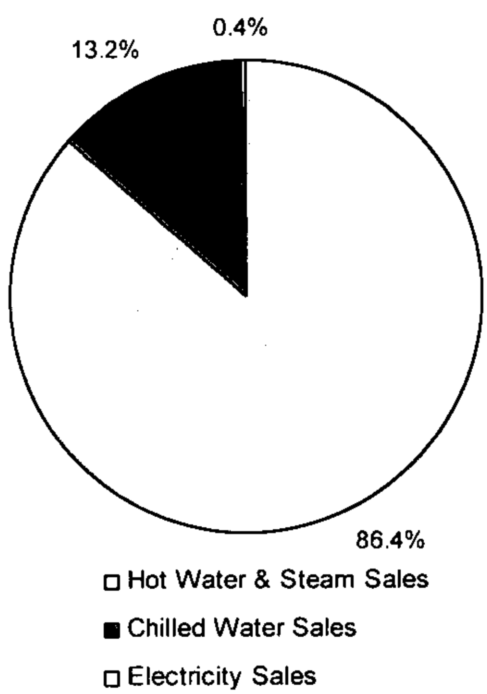
The London District Energy System

The London District Energy System is a district energy system located in London, Ontario with a total distributing capacity of approximately 156,000 lbs/hour of steam and 2,850 tons of chilled water, totaling approximately 56.1MW of thermal generation capacity. The London District Energy System produces steam and chilled water from one facility that uses natural gas as its primary fuel and fuel oil as its alternative fuel. The London District Energy System was significantly upgraded in 1994 to enhance its steam and distribution system and to add cooling capability. The distribution system consists of 8 km of steam distribution and 2 km of chilled water distribution.

Steam, Hot Water and Electricity Sales

The London District Energy System sells steam and chilled water to a diversified customer base, including the London Health Sciences Centre. Approximately 68% of the system's revenues were generated from investment grade or government-funded entities in 2006. Customer contracts include price escalators which generally provide for a pass-through of fuel costs, thereby mitigating the impact of energy price and weather volatility. The London District Energy System has been able to add additional steam and chilled water customers on a consistent basis. In addition, the London District Energy System has expansion opportunities in both the steam and the chilled water markets. Historically the London District Energy System has generated and sold a small amount of electricity. With the development of the London Cogen Facility, such generation sales shall cease.

REVENUE BREAKDOWN BY SOURCE
YEAR ENDED DECEMBER 31, 2006



Customers

The London District Energy System's 10 largest customers as measured by 2006 revenue are listed in the following table.

Energy Purchaser	S&P Credit Rating	Contract Expiry	% of 2006 Revenue
London Health Sciences Centre	Government Funded[1]	2011	16.6%
London Hospital Linen Service	Government Funded[1]	2021	10.01%
City Centre (Osmington Inc.)	Not Rated	2013	7.3%
London Free Press (Sun Media Corporation)	(B+)	2008	7.2%
City and Centennial Hall (City of London)	Government Funded[1]	2007[2]	5.2%
Royal Host Hotels (Hilton)	(BBB)	2021	7.1%
Galleria London	Not Rated	2010	7.0%
Court House (Ontario Crown Corporation)	Government Funded[1]	2013	3.8%
Federal Buildings (Government of Canada)	AAA	2009	4.0%
London Public Library	Not Rated	2021	1.8%
Total			**70.0%**

(1) Government-funded customers receive substantial direct and/or indirect support of one of, or a combination of, the federal, provincial, or municipal governments. The S&P credit ratings for Canada and Ontario are "AAA" and "AA" respectively.

(2) Automatic five-year renewals.

Energy Generation

The London District Energy System generates steam and chilled water utilizing two 1.5MW gas turbine generators and two backpressure steam turbines. Waste steam from the turbines is used internally to produce chilled water or is sent directly to the steam distribution system. In addition, chilled water is produced at four other sites, utilizing one 570-ton capacity steam absorption chiller, one 580-ton capacity hot water absorption chiller and three electric chillers (600, 700 and 800-ton capacity units). Steam is generated from one 60,000 lbs/hour boiler, two 35,000 lbs/hour boilers and one heat recovery unit capable of 30,000 lbs/hour.

Plant	Capacity	Equipment	Fuel Supply
London District Energy System	156,000 lbs/hour (steam) 2,850 tons (chilled water) 3.6MW (electricity)	• Three boilers and one heat recovery steam generator • Two backpressure steam turbines • One steam absorption chiller • Three electricity-powered chillers • Two gas turbines	• Natural gas (primary) • Fuel oil (backup)

Fuel and Water Supply

Natural gas is purchased through a natural gas marketer and is distributed by the local gas distribution company, Union Gas Limited, through a high-pressure gas line. Fuel oil is readily available in London. Boiler feed water is supplied by the local municipality.

Employees, Operations and Maintenance

There are a total of 11 full-time employees at the London District Energy System. Eight of the employees are members of the Communications, Energy and Paper workers Union of Canada. The London District Energy System has not experienced a work stoppage in more than 30 years. The administrative offices for the London District Energy System are located on separate premises in London, along with the Fund's administrative offices, and are leased under a short-term arrangement.

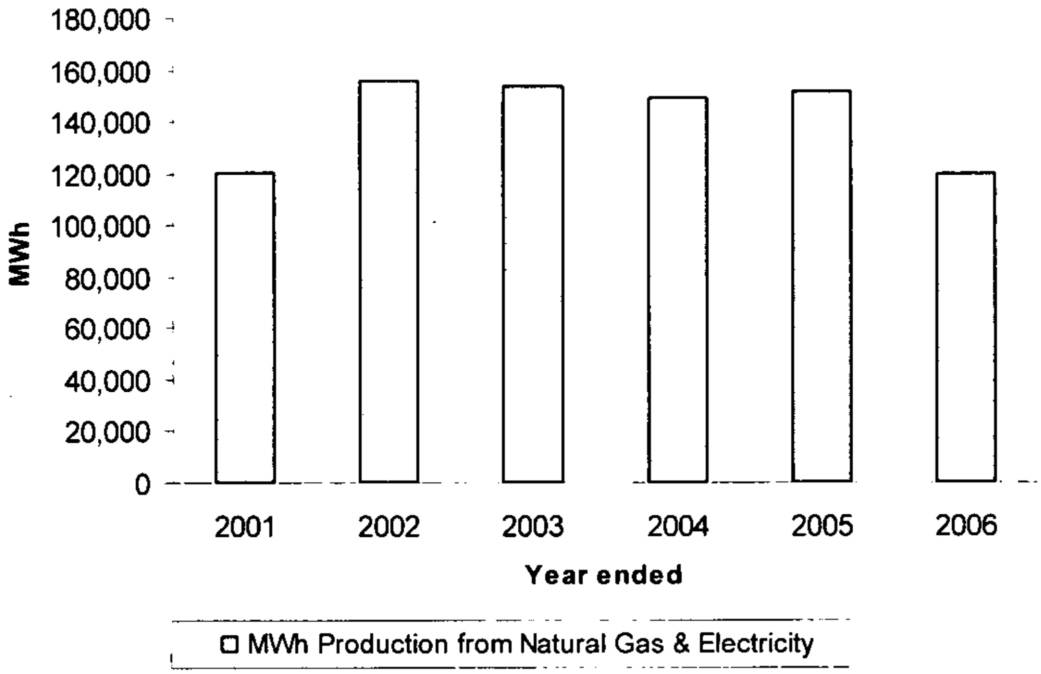
Environmental

The London District Energy System is in material compliance with environmental laws, and has not received any notices or citations relating to environmental compliance. The London District Energy System is required to report its air emissions data to the Ontario Ministry of the Environment every two years. In addition, there is a federal requirement to report emissions data annually under the National Pollutant Release Inventory program.

Operating History

Sales volumes for the London District Energy System have increased over the past number of years and most significantly in 2001 and 2002 with the addition of the London Health Sciences Centre as a customer. Also, chilled water sales have increased with the addition of new customers over the past number of years.

LONDON DISTRICT ENERGY SYSTEM ENERGY PRODUCTION



THE COGEN FACILITIES

California Cogen Facilities

Overview

The California Cogen Facilities are located in California, one in Ripon and one in Pomona and have approximately 93.5 MW of electrical generation capacity. The following chart summarizes the California Cogen Facilities electrical capacity. The California Cogen Facilities are each QF's and produce electricity and steam using natural gas fuel. Each California Cogen Facility sells electricity to a local utility pursuant to a long term PPA and steam to a third party steam host pursuant to a steam sales agreement.

SUMMARY OF COGENERATION FACILITIES ELECTRIC CAPACITY (MWh)

CALIFORNIA COGEN FACILITIES SUMMARY

Facility	City	MW	Power Purchaser Customers[1]	Purchase Agreement Expiry	Customer S&P Credit Rating
Ripon	Ripon	49	Pacific Gas & Electric	2016	BBB
San Gabriel	Pomona	44.5	Southern California Edison	2018	BBB+
Total		**93.5**			

The Ripon Facility

The Ripon Facility is a nominal 49.5 MW (gross output) gas-fired cogeneration plant located in Ripon, California, approximately 130 kilometers east of San Francisco. The Ripon Facility generally operates as a base load facility. The Ripon Facility is a QF under the regulations of the FERC implementing PURPA, and thus is currently exempt from rate regulation as an electric utility under federal and state law.

A General Electric LM-5000 combustion turbine generator and an IHI power turbine generate electricity at the Ripon Facility. The combustion turbine technology is based on an aircraft engine design that is known for rapid starting and stopping capability and more efficient performance as compared to industrial frame combustion turbines.

The Ripon Facility produces steam from a heat recovery steam generator ("HRSG") and, when needed, from an auxiliary boiler. The full steam production from the HRSG can be used internally, primarily for steam injection into the combustion turbine.

Power Purchase Agreement

Electrical capacity and energy is sold pursuant to a Long-Term Energy and Capacity Power Purchase Agreement executed by Simpson Paper Company, as Seller, on November 12, 1984 and by PG&E as Buyer, on April 5, 1985 (the "Ripon PPA"). The Ripon PPA has been amended on three occasions and was assigned by Simpson Paper Company to Ripon Cogeneration Inc. in 1996, the predecessor in interest to Ripon Cogeneration. Ripon Cogeneration Inc. was subsequently converted into Ripon Cogeneration in 2004. The term of the Ripon PPA extends for a period of 30 years from the firm capacity availability date of April 25, 1988. The Ripon Facility is required to operate throughout the term of the agreement as a QF in accordance with the cogeneration facility requirements established by FERC pursuant to PURPA as those requirements existed on the effective date of the agreement.

The Ripon PPA provides for capacity payments for firm capacity, first incremental capacity and second incremental capacity. The formula for firm capacity payments is the product of: (1) the firm contract capacity of 42,000 kW; (2) the contract capacity price of US$172 per kW per year; (3) a capacity loss adjustment factor; and (4) a performance bonus factor. Firm capacity payments are applicable only in periods during which the Ripon Facility's forced outage rate is less than twenty percent. In addition, the firm capacity payments are weighted by allocation factors for each period as defined by the CPUC which are weighted towards the peak hours, particularly during the summer period of May 1 through September 30. The firm capacity performance bonus is based upon the Ripon Facility's availability factor during the summer peak months of June, July and August. The performance bonus factor is calculated as the ratio of the previous five-year average peak capacity factor during the summer peak hours divided by eighty-five percent.

The formula for the first incremental capacity for capacity deliveries above 42,000 kW and up to 44,500 kW is the product of: (1) the first incremental capacity of up to 2,500 kW; (2) the first incremental contract capacity price of US$188 per kW per year; (3) a capacity adjustment loss factor; and (4) an allocation factor which accounts for the quantity of first incremental capacity delivered during specified periods. Finally, the formula for second incremental capacity for capacity deliveries above 44,500 kW and up to 54,000 kW is the product of: (1) the first incremental capacity of up to 9,500 kW; (2) the second incremental contract capacity price as authorized from time to time by the CPUC; (3) a capacity adjustment loss factor; and (4) an allocation factor which accounts for the quantity of second incremental capacity delivered during specified periods.

Under the Ripon PPA, PG&E is required to accept delivery of all energy and capacity generated by the Ripon Facility except during periods of forced outage, *force majeure*, emergencies or to comply with prudent industry practice, or if necessary to allow PG&E to shut down its system for inspection, repair or maintenance. In such instances, PG&E is not required to accept or pay for deliveries of energy and may require the Ripon Facility to reduce energy deliveries. However if the Ripon Facility is prevented from meeting performance requirements because of a forced outage of PG&E's system, PG&E must continue to make the full capacity payments. During periods of "hydro-spill" conditions, as defined by the CPUC, and generally meaning those periods when purchases from QFs and other conditions on the PG&E system would otherwise require that PG&E spill water at its hydroelectric facilities without being able to generate electricity, therefore, PG&E has the right to curtail deliveries of energy from the Ripon Facility and, if energy from the Ripon Facility is delivered to PG&E, the energy price will be the hydro-savings price quoted by PG&E. PG&E also has the right to curtail deliveries from the Ripon Facility in excess of 37,000 kW during all super off-peak hours (generally from 1:00 a.m. to 5:00 a.m. during each calendar day) and during any period when PG&E would otherwise incur "negative avoided costs" (generally, the utility would incur greater costs backing down its generation than the costs avoided through purchases from QFs).

Beginning on April 25, 1998, the energy payments under the Ripon PPA were made equal to PG&E's full short-run avoided operating costs. Subsequently, in 2001, the parties entered into an amendment to the Ripon PPA providing for the payment of energy prices reflecting an average energy price of US$53.76 per MWh over a five-year term, subject to adjustment through the application of time-of-use factors as defined by the CPUC. Following the expiration of the amendment on June 30, 2006, Ripon Cogeneration's energy payment reverted to PG&E's full short run avoided costs, commonly referred to as "Short-Run Avoided Cost" or "SRAC".

SRAC is established for each utility, from time to time by the CPUC. The CPUC has, since the 1980's, established various SRACs for PG&E and SCE. The methods to establish SRAC have also been modified from time to time by the CPUC and by the California legislature when it enacted section 390 of the Public Utilities Code ("PUC"). Factors that the CPUC have typically considered are fuel prices, the efficiency of utility generators, operations and maintenance costs and a time-of-use adjustment. PUC section 390 provides that until the CPUC determines that the Power Exchange, now defunct and not anticipated to function in the future, is functioning properly, SRAC shall be determined in accordance with PUC section 390(b). PUC section 390(b) directs that SRAC be based on a formula that reflects a 1996 starting energy price, adjusted monthly to reflect changes in a starting gas index price in relation to an average of current California natural gas border price indices. In December 2003, the CPUC issued decision D. 03-12-062, expressing the concern that "the SRAC pricing formula may need to be revised in light of the current energy market. Therefore the Commission should carefully consider how to modify the SRAC methodology and whether to seek legislative changes" to PUC section 390. In April 2004 the CPUC initiated a proceeding, CPUC docket R. 04-04-025 to address SRAC and other issues. Hearings in docket R. 04-04-025 were held in January and February 2006 and briefs were submitted in March. The outcome of such proceedings is unknown and hence, future energy prices of Ripon Cogeneration cannot be predicted.

Steam Sales

Process steam from the Ripon Facility is sold to Fox River Paper Company ("Fox River") under an Amended and Restated Steam Agreement ("Ripon Steam Agreement") by and between Fox River and Simpson Paper Company dated September 30, 1996 which terminates on April 19, 2018. The Ripon Steam Agreement was assigned to Ripon Cogeneration, Inc. in 1996 which subsequently converted into Ripon Cogeneration in 2004.

Fox River is the only producer of text and cover, a value-added grade of uncoated freesheet, on the West Coast of the United States. While Fox River is subject to certain market pressures relating to rising pulp prices and declining demand for text and cover, its leading competitive position in this industry is expected to minimize the impact of these pressures.

On or about March 1, 2007 a subsidiary of Neenah Paper, Inc. (NYSE: NP) merged with and into Fox Valley Corporation, the parent of Fox River. Accordingly, Fox River is now an indirect wholly-owned subsidiary of Neenah Paper, Inc.

Under the Ripon Steam Agreement, Fox River is obligated to accept a sufficient quantity of steam for the Ripon Facility to maintain QF status and supply all of the Ripon Facility's process water needed to satisfy the steam obligation. Fox River is required to return a minimum amount of the condensate meeting certain requirements. If Fox River returns less than the minimum amount of condensate, it is obligated to compensate the Ripon Facility for costs incurred by the Ripon Facility for obtaining additional quantities of process water. If Fox River returns condensate in excess of a certain amount, the Ripon Facility is obligated to pay Fox River a bonus to reflect the savings received by the Ripon Facility as a result of having to obtain less process water.

The Ripon Facility is obligated to supply up to 75,000 pounds of steam per hour and must utilize an auxiliary boiler to meet the steam demand when the gas turbine is not operating. The formula to determine the price payable by Fox River for steam is the product of: (1) the total quantity of steam delivered; (2) a thermal conversion factor which is 1.3 MMBtus per thousand pounds of steam for the first ten years of the Ripon Facility Steam Agreement and 1.0 MMBtus for the remainder of the term; and (3) the cost of natural gas purchased by the Ripon Facility. Fox River is also responsible for all sales, use or other transfer taxes imposed upon the sale of steam under the agreement. Under the Ripon Steam Agreement, Ripon must pay liquidated damages for periods of steam supply disruption. The disruption compensation payment is capped at US$25,000 for any 24 hour period and US$1.8 million for any 12-month period. Ripon Cogeneration paid liquidated damages to Fox River of US$50,000, and $US33,634 in 2005 and 2006 respectively. In addition, if a steam supply disruption occurs which is not permitted by the Ripon Steam Agreement Fox River may, but is not obligated to, assume operational control of the auxiliary boiler and related equipment until such steam supply disruption has been cured.

Other provisions address measurement of steam and water deliveries, billing and payment, operation of the facility and maintenance of the steam supply and condensate return lines, events of default and termination, *force majeure*, insurance, indemnity and dispute resolution which the Manager believes are customary in the industry. Fox River has the right to terminate the Agreement for convenience at various times during the term of the Agreement for specified reasons. In the event of a termination for convenience, Fox River is obligated to pay the lesser of $5 million (adjusted on April 1st of each year by an amount equal to the percentage change in the Producer Price Index during the preceding 12-month period) or the reasonable actual cost incurred in building an alternative steam host for the Ripon Facility. In addition, Fox Paper is obligated to enter into good faith negotiations for the sale of land at the site suitable for the location of an alternative steam host. Each party has the right to terminate the Agreement for an event of default by the other party, including the failure for reasons other than a *force majeure* event of the Ripon Facility to supply steam for more than thirty consecutive days or more than fifty-two days during any 12-month period.

If the Fox River Steam Agreement was terminated and a replacement steam host not timely obtained or built, the Ripon Facility could lose its QF status and PG&E could seek to terminate the Ripon PPA. However, while Fox River has the right to terminate the Fox River Steam Agreement at its convenience, management believes that it would be unlikely to exercise this right as it would not be economical for Fox River to produce its own steam and a significant payment would be required to be paid to Ripon. For a more detailed discussion of the risks associated with loss of QF status, see "Risk Factors — Qualifying Facility Status at Ripon Cogeneration and USEB".

Fuel

Full natural gas requirements were supplied to the Ripon Facility under a fixed price contract with BP Energy Company ("BP") that expired on June 30, 2006. In the period from July 1, 2006 to September 30, 2006, the Ripon Facility entered into an agreement with BP at pricing which was reset monthly and correlated with a location-based gas index price.

Commencing October 1, 2006, the Ripon Facility entered into a fuel purchase agreement with Sempra Energy Trading ('Sempra") that terminates on March 31, 2008 (the "Ripon Gas Contract"). Under such Ripon Gas Contract, Sempra supplies a contract quantity of 6,500 MMBtu's per day plus or minus five percent (5%) to the Ripon Facility on a firm basis with the balance of the Ripon Facility's gas requirements in excess of the firm contract quantity supplied on an interruptible basis. The price under the Ripon Gas

Contract resets monthly and is correlated with a location-based gas index price. Under certain circumstances, Ripon Cogeneration may replace the index price with a fixed price offered by Sempra. In addition to supplying natural gas to the Ripon Facility, Sempra is designated "balancing agent" for the Ripon Facility and, in that capacity, is responsible for all scheduling, nominations and balancing fuel consumption and deliveries. Imbalances are paid for by Sempra subject to certain conditions. The delivery point under the Gas Contract is at the interconnection between the PG&E backbone transmission system and its distribution system at the PG&E Citygate.

Under the Ripon Gas Contract, each party has a right to terminate the contract only in limited circumstances, including in the failure to give adequate assurances of performance when required to be given under the contract and a Default (as defined in the Agreement) by the other party. In the event of an early termination, a "Termination Payment" shall be paid equal to the difference between the "Contract Value" and the "Market Value" as such terms are defined in the Agreement over the remainder of the term of the Agreement, discounted to present value as of the early termination date with Sempra paying to Ripon Cogeneration the excess of the Market Value over the Contract Value and Ripon Cogeneration paying to Sempra the excess of the Contract Value over the Market Value. So long as the pricing under the Gas Contract is index based, such damages are unlikely to be material. In addition, if Sempra fails to deliver the Ripon Facility's full requirement of natural gas, Sempra shall pay Ripon Cogeneration the difference between the contract price and the cost of obtaining replacement fuel on a commercially reasonable basis as well as certain costs and penalties. The parties' obligations under the Ripon Gas Contract may be suspended during a force majeure. In the event that Sempra claims a force majeure for more than 30 days in any ninety day period, either party may terminate the Ripon Gas Contract in which case a Termination Payment shall be due.

The Manager expects that the effective natural gas indices used in the PG&E SRAC formula will continue to substantially correlate with the location based index price contained in the Ripon Gas Contract, although there is a possibility such correlation will not be complete in the event PG&E's SRAC is modified. Sempra and Ripon Cogeneration have agreed to negotiate in good faith the terms and conditions respecting the sales of gas above the firm daily volume in the event the Ripon Facility's gas requirements change due to a change in the PG&E SRAC formula or a modification or replacement of existing equipment at the Ripon Facility.

Natural gas transportation service for the Ripon Facility is provided pursuant to a Natural Gas Service Agreement with PG&E that provides for the firm transportation of a maximum daily quantity of 13,000 decatherms per day. Transportation service is priced at a rate that is set and may be changed from time to time by the CPUC. The Ripon Facility receives transportation service under two different PG&E rate schedules. Rate Schedule G-EG applies to the transportation of the natural gas used in the combustion turbine at the Ripon Facility while Rate Schedule G-NT applies to the natural gas burned in the auxiliary boiler. The PG&E Ripon transportation agreement was effective for an initial one-year term commencing on January 1, 2007 and continues on a month-to-month basis after the initial term unless terminated by either Ripon Cogeneration or PG&E. However, PG&E may only terminate the agreement with the approval of or pursuant to an order by the CPUC.

Environmental Health and Safety

The Ripon Facility and its operations are subject to an environmental health and safety regulatory regime including federal, state, regional, local and municipal laws, regulations and permits relating to, among other things: air emissions, water and wastewater treatment, worker health and safety and site contamination. The Manager believes that the Ripon Facility has obtained (or timely applied for renewal of) and is currently in material compliance with, the material environmental permits and approvals currently necessary to operate the Ripon Facility. A Phase I Environmental Site Assessment was completed in 2003 and no material issues of concern were identified relative to potential soil or groundwater contamination.

In May 2006, the Ripon Facility performed a diagnostic test which revealed that the auxiliary boiler could not be operated in compliance with its operating permits at all load conditions. Since that date, the Ripon Facility has received variances from the San Joaquin Valley Unified Air Pollution Control District (the San Joaquin District") which, among other things, permit the Ripon Facility to operate the auxiliary boiler with excess NOx and CO emissions subject to certain conditions. The current variance expires on the earlier of October 31, 2007 or until the subject boiler achieves compliance with the permitted emission limit, whichever comes first. Ripon Cogeneration is currently exploring different methods of achieving compliance including equipment modifications and permit modifications.

From time to time, Ripon Cogeneration has received notices of violation ("NOV's") from the San Joaquin District respecting alleged violations of applicable laws and permits. Such NOV's do not allege excess emissions (except in one case involving an immaterial amount of excess emissions of short duration) but mainly relate to data collection and reporting. Ripon Cogeneration has settled certain of the NOV's for immaterial sums and intends to contest or resolve the pending NOV's on terms which are not expected to be materially adverse to the Fund. Ripon Cogeneration is in the process of upgrading its data collection equipment. The Manager believes such upgrade will address the compliance issues raised by the NOV's on a long-term basis.

Site Rights and Expansion Opportunities

The site upon which the Ripon Facility is located is owned by Ripon Cogeneration. The site consists of approximately two acres of land located adjacent to the Fox River Paper Mill within an area occupied by industrial uses. Ripon Cogeneration maintains certain easement rights, which are necessary in connection with the operation of the Ripon Facility. The Ripon Facility is well-situated for expansion of its power generating capacity. Electrical and gas interconnections are already in place and capable of handling significantly more flow than is currently being utilized.

Operating & Maintenance

Operation and maintenance services are provided to the Ripon Facility pursuant to an operation and maintenance agreement (the "Ripon O&M Agreement") dated October 22, 2003. The contract is between Rockland California Partners LLC (which subsequently merged into Ripon Cogeneration), as the owner, and North American Energy Services Company as the Operator ("NAES" or the "Operator"). All employees at the Ripon Facility are employed by NAES and provide operational and maintenance services to the Ripon Facility under the Ripon O&M Agreement. NAES is one of the largest third-party providers of power plant operations and maintenance services with an experience base of more than 19,000 MW of generation capacity. NAES is owned by an affiliate of ITOCHU Corporation. The Ripon O&M Agreement has a term of seven years expiring on January 27, 2011. Services provided by the Operator include all operation and maintenance activities.

The Ripon O&M Agreement provides for payment of reimbursable costs, operating costs and an operator payment on a monthly basis. Reimbursable costs include such items as relocation and recruitment expenses for on-site personnel and the cost of operator's insurance. Operating costs include equipment, material supplies, consumables, spare parts, office expenses, utilities, training, contractors, permit fees, payroll and other similar costs. The operator payment includes a management fee, project management fee and an incentive payment.

GE Engine Lease Agreement

In order to mitigate the risk of engine failure, Ripon Cogeneration has entered into a service lease agreement for the Ripon Facility with General Electric Company ("GE") (the "Ripon GE Lease") under which GE is to repair or deliver a replacement engine to Ripon within certain specified time periods after notice from Ripon Cogeneration of an engine failure. Under the Ripon GE Lease, Ripon Cogeneration pays an annual fee plus a usage fee for each week that the replacement engine is used. The Ripon Cogeneration GE Lease runs through October 18, 2012 but may be terminated by either party under certain conditions including a material breach by the other party. The Ripon GE Lease provides for liquidated damages in the event GE fails to perform subject to caps and limitations. In the event Ripon Cogeneration replaces the LM-5000 turbine with an LM- 6000 turbine, the Ripon GE Lease will be converted to an LM-6000 lease with a market-based price adjustment.

IHI Turbine Sub-Assembly Lease Agreement

In order to mitigate the risk of turbine failure, Ripon Cogeneration has entered into a turbine sub-assembly lease agreement for the Ripon Facility with IHI, Inc. ("IHI") (the "Ripon IHI Lease") under which IHI provides replacement parts for the turbine sub-assembly on-site. Under the Ripon IHI Lease, Ripon Cogeneration pays a base fee plus a usage fee for each week that the replacement turbine sub-assembly is used based on a fee schedule. The Ripon IHI Lease runs through April 30, 2009 and automatically renews for one additional 5 year term unless either party provides the other party with written notice of its intention not to renew. The Ripon IHI Lease may be terminated by either party for convenience with six months written notice or in the case of a breach by the other party. The Ripon IHI Lease contains certain limitations on IHI's liability for failure to perform. The following table sets out the historical generation, steam sales, availability and heat rate information for the Ripon Facility, as confirmed by an independent engineering due diligence assessment conducted by Stone and Webster Management Consultants Inc. ("Stone and Webster Consultants").

	2006	2005	2004	2003	2002
Net generation (MWh)	226,233	275,303	324,751	381,607	340,955
Steam sales (thousands of lbs)	310,404	275,988	297,839	267,526	339,311
Annual operating factor	58.5%	97.0%	83.9%	95.1%	85.8%
Peak operating factor	96.6%	100%	98.4%	95.5%	94.6%
Heat rate (BTU/kWh)	10,314	9,496	9,663	9,516	9,573

The San Gabriel Facility

The San Gabriel Facility is a nominal 44.5 MW (gross output) gas-fired cogeneration plant located in Pomona, California, approximately 50 kilometers east of Los Angeles. The San Gabriel Facility generally operates as a base load facility. The San Gabriel Facility is a QF under the cogeneration regulations of the FERC implementing PURPA and thus is currently exempt from rate regulation as an electric utility under federal and state law.

Similar to the Ripon Facility, a General Electric LM-5000 combustion turbine generator and an IHI power turbine generate electricity at the San Gabriel Facility. The San Gabriel Facility produces steam from a HRSG. A portion of the steam production from the HRSG can be used internally, primarily for steam injection into the combustion turbine.

Power Purchase Agreement

Electrical capacity and energy are sold from the San Gabriel Facility pursuant to a Power Purchase Contract with an effective date of September 7, 1983 but executed in a revised form by Simpson Paper Company as Seller on November 8, 1984, and SCE, as Buyer, on the same date (the "San Gabriel PPA"). The San Gabriel PPA was assigned by Simpson Paper Company to Ripon Cogeneration, Inc., in 1997, which was subsequently converted into Ripon Cogeneration in 2004. The term of the San Gabriel PPA extends for a period of 30 years from the Firm Operation date in January 1986 and continues thereafter until either party gives 90 days prior written notice of termination. The San Gabriel Facility is required to operate throughout the term of the agreement as a QF in accordance with the cogeneration facility requirements established by FERC pursuant to PURPA as those requirements existed on the effective date of the agreement.

The San Gabriel PPA provides for payments for firm capacity, as-available capacity and energy. The formula for firm capacity payments is the product of: (a) the Contract Capacity Price of US$158 per kW per year and (b) conversion factors to convert annual capacity prices to monthly payments by time of delivery as specified in Standard Offer No. 2 Capacity Payment Schedule, subject to periodic adjustments by the CPUC and (c) Contract Capacity of 36,000 kW and (d) a performance factor. Firm capacity payments are applicable only in periods during which the San Gabriel Facility meets a performance requirement of a forced outage rate less than twenty percent for all on-peak hours during each peak month ("Performance Requirement"). In addition, there are provisions for capacity bonus payments during both peak and non-peak months. To qualify for a bonus payment during on-peak months, the San Gabriel Facility must (i) meet the Performance Requirement and (ii) achieve a capacity factor in excess of 85% during the peak month. To qualify for a bonus payment during non-peak months, the San Gabriel Facility must (i) meet the Performance Requirement and (ii) achieve a capacity factor in excess of 85% during each peak month of the previous twelve months and (iii) achieve a capacity factor in excess of 85% during the non-peak month. As-available capacity rates are established by, and subject to, periodic revision by the CPUC. The San Gabriel Facility has achieved bonus payments in 16 of 16 peak months in the last 44 months and 31 of 32 non-peak months in the last 44 months.

If the San Gabriel Facility fails to meet the Performance Requirement, SCE may place the San Gabriel Facility on probation. If the San Gabriel Facility fails to meet the Performance Requirement during the probationary period, SCE may reduce the Contract Capacity, which would reduce future firm capacity payments and subject the San Gabriel Facility to a refund obligation based on the difference between the original Contract Capacity and the reduced Contract Capacity, plus interest thereon.

SCE is not required to accept delivery of all energy generated by the San Gabriel Facility if necessary to allow SCE to maintain its equipment or to maintain SCE system integrity. If the San Gabriel Facility is prevented from meeting performance requirements because of forced outage on SCE's system, SCE must continue to make the full capacity payments. The San Gabriel PPA provides that SCE may curtail deliveries of energy for no more than 300 hours per calendar year during off-peak hours when purchases from the San Gabriel Facility would either result in costs greater than energy from other sources or require that SCE hydro-energy be spilled.

Beginning on January 2, 1996, the energy payments under the PPA are equal to SCE's full short-run avoided operating costs. In 2001 the parties entered into an amendment to the San Gabriel PPA providing for payment for energy pursuant to a formula specified in the amendment. Following the expiration of the amendment on June 30, 2006, the San Gabriel Facility's energy payments reverted to SCE's full SRAC. In April 2004, the CPUC initiated a proceeding, CPUC docket R. 04-04-025 to address SRAC and other issues. Hearings in docket R. 04-04-025 were held in January and February 2006 and briefs were submitted in March 2006. The outcome of this regulatory proceeding and hence future energy prices under the San Gabriel PPA cannot be predicted. For a more detailed discussion of SRAC see "The Ripon Facility — Power Purchase Agreement".

It is probable that in the event that the San Gabriel Facility fails to maintain QF status or commits a material breach of the San Gabriel PPA, SCE could assert that it may terminate the San Gabriel PPA.

Steam Sales

Process steam from the San Gabriel Facility is sold under a steam sales agreement dated May 20, 1997 between Simpson Paper Company and Smurfit Packaging Corporation (the "San Gabriel Steam Agreement"). Smurfit assigned its interest in the San Gabriel Steam Agreement to Blue Heron Paper Company of California LLC ("Blue Heron") and the Simpson Paper Company assigned its interest to Ripon Cogeneration Inc., Ripon's predecessor in interest which was converted into Ripon Cogeneration in 2004. The San Gabriel Steam Agreement expires on January 1, 2016.

Blue Heron supplies recycled newsprint primarily to commercial printers in the Los Angeles area with the remainder supplied to smaller daily newspapers. Blue Heron relies on the above-average speed capability of its 240" machine and its geographic proximity to recovered paper supplies and end use markets to maintain a delivered cost advantage over larger competitors. It is anticipated that Pomona, California, the urban market in which Blue Heron principally operates, will face increasing pressure from declining real product prices and rising real recovered paper prices due to offshore demand and fluctuations in natural gas markets. These risks, however, are partially mitigated by Blue Heron's geographic proximity to supply sources and its strong competitive position.

Pursuant to the San Gabriel Steam Agreement, Blue Heron is obligated to purchase the minimum quantity of steam necessary for the San Gabriel Facility to maintain QF status. The San Gabriel Facility is responsible for makeup water supply and no condensate is returned from Blue Heron. The San Gabriel Facility is obligated to supply up to 45,000 pounds of steam per hour during periods when the gas turbine is in operation. The price payable by Blue Heron for steam is determined by a formula in which: (1) the product of (a) the total quantity of steam (b) the thermal conversion factor and (c) the cost of fuel is (2) added to the cost of (x) water plus (y) the cost of chemicals to treat boiler feed water plus (z) the actual incremental cost of treating boiler feed water. Blue Heron is also responsible for all sales, use or other transfer taxes imposed upon the sale of steam under the agreement. Under the San Gabriel Steam Agreement, Ripon Cogeneration is obligated to pay liquidated damages for periods of steam supply disruption not permitted by the agreement. This disruption compensation payment is subject to an annual cap and is not considered material. Except for: (a) indemnities related to liabilities resulting from (i) bodily injury, sickness, disease or death of any person, or (ii) damage or destruction of real or personal property; or (b) environmental matters; no party's liability for breach of the San Gabriel Steam Agreement shall exceed US $3,000,000. Ripon Cogeneration paid Blue Heron liquidated damages of approximately US$35,000 in 2006.

Other provisions address measurement of steam deliveries, billing and payment, operation of the facility and maintenance of the steam line, events of default and termination, force majeure, insurance, indemnity and dispute resolution which management believes are customary in the industry. Both parties have the right to terminate the San Gabriel Steam Agreement for an event of default by the other party. In addition, Blue Heron has the right to terminate the San Gabriel Steam Agreement in connection with the permanent closure of its newsprint recycling facility. If this permanent closure occurs within the first twelve years of the San Gabriel Steam Agreement, Blue Heron is obligated to reimburse the San

Gabriel Facility for the cost of constructing the steam line interconnecting the Facility and the recycling facility, which reimbursement is reduced in equal amounts annually on the anniversary of the effective date of the San Gabriel Steam Agreement during the first twelve years of the agreement and do one of the following: (a) pay an amount equal to the lesser of (i) the reasonable actual costs incurred in building an alternative steam host at the San Gabriel Facility or (ii) US $3 million or (b) provide an alternative steam host for the San Gabriel Facility that will allow the San Gabriel Facility to continue to qualify as a QF and is otherwise acceptable to Ripon. If Blue Heron elects to provide the San Gabriel Facility with an alternative steam host and the steam line continues to be used to provide service to such new steam host, Blue Heron is not obligated to reimburse the San Gabriel Facility for the cost of constructing the steam line.

On March 7, 2007, Blue Heron announced that it had issued a plant closing warning to its employees at the paper mill which serves as the Steam Host for the San Gabriel Facility. In the announcement, Blue Heron claimed that the potential closing was due to shrinking margins caused by recently increasing waste paper costs and decreasing newsprint prices. At this juncture, it is uncertain whether the mill will close. A mill closing may have a material adverse effect on the San Gabriel Facility's QF Status unless alternative steam sales arrangements are made. The Manager is currently exploring various measures to mitigate against any such adverse effect including alternative arrangements with Blue Heron that would protect the San Gabriel Facility's QF even if the paper mill ceases or suspends its current operations and obtaining a temporary exemption (i.e. one to two years) from QF useful heat output requirements from the FERC while more long-term solutions are implemented. Under the steam sales agreement, Blue Heron is required to purchase a minimum volume of steam annually from the San Gabriel Facility and is liable for costs associated with replacing Blue Heron as a steam customer to preserve the San Gabriel Facility's QF status, up to a limit in excess of US $4,000,000. Subject to preservation of QF status, the adverse effect of a mill closing on the Fund would not be expected to be material. See "Risk and Uncertainties – Risks Related to the Business – Qualifying Facility Status at Ripon Cogeneration and USEB".

Fuel

Full natural gas requirements were supplied to the San Gabriel Facility under a fixed price contract with BP Energy Company ("BP") that expired on June 30, 2006. In the period from July 1, 2006 to September 30, 2006, the San Gabriel Facility entered into an agreement with BP at pricing which was reset monthly and correlated with a location-based gas index price.

Commencing October 1, 2006, the San Gabriel Facility entered into a fuel purchase Sempra that terminates on March 31, 2008 (the "San Gabriel Gas Contract"). Under such San Gabriel Gas Contract, Sempra supplies a contract quantity of 6,500 MMBtu's per day plus or minus ten percent (10%) to the San Gabriel Facility on a firm basis with the balance of the San Gabriel Facility's gas requirements in excess of the firm contract quantity supplied on an interruptible basis. The price under the San Gabriel Gas Contract resets monthly and is correlated with a location-based gas index price. Under certain circumstances, Ripon Cogeneration may replace the index price with a fixed price offered by Sempra. In addition to supplying natural gas to the San Gabriel Facility, Sempra is designated "balancing agent" for the San Gabriel Facility and, in that capacity, is responsible for all scheduling, nominations and balancing fuel consumption and deliveries. Imbalances are paid for Sempra subject to certain conditions. The delivery points under the San Gabriel Contract are at any receipt point into the distribution system of Southern California Gas Company ("SoCalGas").

Under the San Gabriel Gas Contract, each party has a right to terminate the contract only in limited circumstances, including in the failure to give adequate assurances of performance when required to be given under the contract and a Default (as defined in the Agreement) by the other party. In the event of an early termination, a "Termination Payment" shall be paid equal to the difference between the "Contract Value" and the "Market Value" as such terms are defined in the San Gabriel Gas Contract over the remainder of the term of the San Gabriel Gas Contract, discounted to present value as of the early termination date with Sempra paying to Ripon Cogeneration the excess of the Market Value over the Contract Value and Ripon Cogeneration paying to Sempra the excess of the Contract Value over the Market Value. So long as the pricing under the Gas Contract is index based, such damages are unlikely to be material. In addition, if Sempra fails to deliver the San Gabriel Facility's full requirement of natural gas, Sempra shall pay Ripon Cogeneration the difference between the contract price and the cost of obtaining replacement fuel on a commercially reasonable basis as well as certain costs and penalties.. The parties' obligations to perform may be suspended during a force majeure. In the event that Sempra claims a force majeure for more than 30 days in any ninety day period, either party may terminate the San Gabriel Gas Contract in which case a Termination Payment shall be due.

The Manager expects that the effective natural gas indices used in the SoCal SRAC formula will continue to substantially correlate with the location based index price contained in the San Gabriel Gas Contract, although there is a possibility such correlation will not be complete in the event SoCal's SRAC is modified. Sempra and Ripon Cogeneration have agreed to negotiate in good faith the terms and conditions respecting the sales of gas above the firm daily volume in the event the San Gabriel Facility's gas requirements change due to a change in the SoCal SRAC formula or a modification or replacement of existing equipment at the San Gabriel Facility.

Natural gas transportation service for the San Gabriel Facility is provided pursuant to a Master Services Contract with SoCalGas that was effective on November 6, 2005, continues for an initial term of two years and continues on a month-to-month basis thereafter unless terminated by either party on no less than twenty days prior written notice. Transportation service is provided under SoCalGas Rate Schedule GT-F which includes both a monthly customer charge and a volumetric charge. The rates may be changed from time to time by the CPUC. Although the transportation service is firm, SoCalGas has the right to curtail service under Rate Schedule GT-F in order to maintain service to certain designated core customers. A customer under Rate Schedule GT-F5 that experiences an interruption of service more than once in any ten-year period is entitled to a credit against its monthly transportation charge.

Environmental Health and Safety

The San Gabriel Facility and its operations are subject to a regulatory regime including federal, state, regional, local and municipal laws, safety regulations and permits relating to, among other things: air emissions, water, work health and safety, wastewater treatment and site contamination. The Manager believes that the San Gabriel Facility has obtained and is currently in material compliance with, the material environmental permits and approvals (or timely applied for renewal of) currently necessary to operate the San Gabriel Facility. A Phase I Environmental Site Assessment was completed in 2003 and nothing of significant concern was identified relative to potential soil or groundwater contamination.

Site Rights and Expansion Opportunities

The site upon which the San Gabriel Facility is located is owned by Ripon Cogeneration. The site consists of approximately two acres located within the former Pomona paper mill site. The paper mill site has been converted to other industrial uses. Ripon Cogeneration maintains certain easement rights, which are necessary in connection with the operation of the San Gabriel Facility. Being in the Los Angeles metropolitan area, the San Gabriel Facility is well-situated for expansion of its power generating capacity. Electrical and gas interconnections are already in place and capable of handling significantly more flow than is currently being utilized.

Operating & Maintenance

Operation and maintenance services are provided to the San Gabriel Facility by NAES pursuant to an operation and maintenance agreement (the "San Gabriel O&M Agreement") substantially similar to the Ripon O&M Agreement. All employees at the San Gabriel Facility are employed by NAES.

GE Engine Lease Agreement

In order to mitigate the risk of engine failure, Ripon Cogeneration has entered into a service lease agreement for the San Gabriel Facility with GE (the "San Gabriel GE Lease") substantially similar to the Ripon GE Lease except that it expires in August 2007.

IHI Turbine Sub-Assembly Lease Agreement

In order to mitigate the risk of turbine failure, Ripon Cogeneration has entered into a turbine sub-assembly lease agreement for the San Gabriel Facility with IHI (the "San Gabriel IHI Lease") substantially similar to the GE IHI Lease.

Operating History

The following table sets out the historical generation, steam sales, availability and heat rate information for the San Gabriel Facility, as confirmed by the independent engineering due diligence assessment conducted by Stone and Webster Consultants.

	2006	2005	2004	2003	2002
Net generation (MWh)	258,265	293,558	273,341	311,672	319,269
Steam sales (thousands of lbs)	289,635	224,406	227,615	254,185	221,207
Annual operating factor	75.3%	81.3%	80.2%	92.9%	93.8%
Peak operating factor	99.9%	96.2%	98.4%	97.6%	100.0%
Heat rate (BTU/kWh)	10,171	9,889	10,117	9,958	9,852

The London Cogen Facility

Overview

Countryside London Cogeneration is currently developing the London Cogen Facility. The London Cogen Facility will be a nominal 19 MW (gross output) gas-fired cogeneration facility located adjacent to the London District Energy System in London Ontario. The London Cogen Facility is scheduled to go into commercial operation in Q2 2008.

The major equipment to be used in the London Cogen Facility is the Solar Titan 130-20501 Axial Turbine Generator Set (the "Generator Set") manufactured by Solar Turbines Incorporated. The turbine rating is a nominal 15 MW. The Generator Set consists of one gas turbine and one generator. The London Cogen Facility will also include a gas-fired Heat Recovery Steam Generator with up to 86 MMbtus per hour lower heating value of duct firing capability, and which shall be connected to the Generator Set and three non-condensing, back pressure steam turbines having a nominal capacity of 4 MW. The combined generating equipment of the London Cogen Facility will have a nominal capacity of 19 MW of electricity (17.24MW nameplate capacity) and will produce up to 130,000 lbs of steam per hour at 650 psig of steam.

The gas turbine will generate at 27.6 KV. A 27.6 KV electric power connection will be made to the existing London Hydro power line near the South-East corner of the London District Energy System's property line. The distance of this interconnect is approximately 25 feet from the transformer. Based on a preliminary inter-connection study, Countryside London Cogeneration believes the existing power line is capable of receiving the new electrical load without any additional modifications.

Countryside District Energy has entered into an Energy Services Agreement with Countryside London Cogeneration for a term of 20 years to purchase all of the London Cogen Facility's steam output. Countryside District Energy will use the steam to provide space heating and cooling to commercial, governmental and residential buildings connected to the London Direct Energy System.

The London Cogen Facility is expected to deliver approximately 83,000 MWh of steam per year to the London District Energy System. The condensate return will be in the form of feed water in an amount equal to the London Cogen Facility's requirements at an expected temperature of approximately 250 degrees Fahrenheit.

The London Cogen Facility will add additional absorption cooling capacity. The London District Energy System will utilize steam from the London Cogen Facility to generate chilled water from its existing and expanded absorption cooling capabilities to supply chilled water to its customers. Chilled water will also be sold under contract to the London Cogen Facility for air inlet cooling.

The Combined Heat and Power Contract

On October 16, 2006, the Ontario Power Authority (the "OPA") and Countryside London Cogen entered into a Combined Heat and Power Contract ("CHP Contract") respecting the development, operation and sale of electricity from the London Cogen Facility. The following summary of certain of the terms of the CHP Contract is qualified in its entirety by all of the terms and conditions of the CHP Contract (including exhibits). For the purpose of this summary of the CHP Contract, capitalized terms have the meaning ascribed in the CHP Contract unless indicated otherwise. The CHP Contract has a term of 20 years commencing on the London Cogen Facility's commercial operation date. Countryside London Cogeneration is obligated to design and build the London Cogen Facility in accordance with the CHP Contract and applicable laws, codes, rules and industry practices.

Countryside London Cogeneration is required to commence Commercial Operation (as defined in the CHP Contract) by June 1, 2008, failing which Countryside London Cogeneration is subject to liquidated damages in accordance with a formula set forth in the CHP Contract. The commercial operation milestone may be adjusted for force majeure. The maximum exposure to Countryside London Cogeneration under this provision would be approximately $1 million dollars.

In addition, if Commercial Operation does not occur within one (1) year after such date, then such failure would permit the OPA to terminate the CHP Contract unless Countryside London Cogeneration has paid all liquidated damages accruing to the one year date and provided the full amount of the required completion and performance security. The failure to reach Commercial Operation within eighteen (18) months after the commercial operation milestone would be considered an event of default giving rise to the right of the OPA to terminate the CHP Contract and sue for damages.

Countryside London Cogeneration has provided completion and performance security to the OPA of $601,500. After Commercial Operation, the amount of the security drops to $312,500 and then drops by $62,500 in each succeeding five (5) year period until year fifteen (15) when it is reduced to $125,000.

Under the terms of the CHP Contract, obligations are imposed upon Countryside London Cogeneration to operate and maintain the availability and capacity of the London Cogen Facility during the Term, meeting all of the applicable laws, regulations rules and codes.

Other than very specific obligations and the obligation to receive Directed Dispatch Orders, no obligations are placed upon Countryside London Cogeneration or the OPA to sell or purchase any electricity or related Products and in fact such obligations are expressly disclaimed.

When the London Cogen Facility operates (actual operation not contractual), Countryside London Cogeneration receives total receipts for electricity production directly from the IESO-administered markets (equal to its actual production in mw-hours multiplied by the Hourly Ontario Electricity Price "HOEP" for each hour). For those same hours of operation, the London Cogen Facility incurs its own actual operating expenses (its actual variable O&M and fuel expenses based on its actual heat rate and variable O&M rate) and pays out these receipts to its respective suppliers.

At the end of the month, the OPA will determine, based on the actual HOEP prices in relation to the Dawn Index the "Market Heat Rate" for every given hour of the month. For those hours where the Market Heat Rate exceeded the London Cogen Facility's "Contract Heat Rate" (seasonal), the London Cogen Facility will be in Deemed Dispatch.

The OPA will then pay to Countryside London Cogeneration a Contingent Support Payment which equals the Fixed Capacity Payment ("FCP") less the Imputed Net Revenue ("INR"). FCP will be based on Countryside London Cogeneration's bid capacity payment subject to downward adjustments for capacity shortfalls from the contract capacity and downward or upward adjustments in the consumer price index. INR is calculated as Gross Energy Market Revenue ("IGEMR") less Imputed Variable Energy Cost (IVEC"). IGEMR equals the product of the London Cogen Facility's deemed dispatched hours and HOEP. IVEC equals the sum of; i) the Contract Heat Rate multiplied by the Dawn Index natural gas rate for each respective hour the project is deemed to be dispatched and ii) the Contract Variable O&M rate multiplied by the total mw-hours for the hours the London Cogen Facility was deemed to be dispatched. IGEMR and IVEC are based on bid Contract Capacity not actual production. There are also potential adjustments for other items which are not expected to be material. If INR is greater than FCP, Countryside London Cogeneration will make a Revenue Sharing Payment to the OPA.

Through the calculation above, the OPA seeks to adjust the Fixed Capacity Payment by the imputed profit margin/loss associated with operating up to the bid Contract Capacity based on the bid Contract Capacity, Contract Heat Rate and Variable O&M bid. Thus Countryside London Cogeneration retains margins from efficiencies relative to the contract rates and will incur additional costs (through reduced Fixed Capacity Payments) if it is less efficient than the Contract bid rates.

Countryside London Cogeneration retains 100% of any energy sales (HOEP x mw-hour production) above the contract production (Contract Capacity x hours deemed to be dispatched).

While Countryside London Cogeneration expects that the London Cogen *Facility* will normally be in Deemed Dispatch, as described above, it is possible that the OPA will issue Directed Dispatch Orders. There are two variations of Directed Dispatch Orders in the CHP Contract: (a) Directed Dispatch Order (DA) — which is a daily directed dispatch order and (b) Directed Dispatch Order (LT) — which is a long term dispatch order for periods of one (1) or more calendar months. In order to assist Countryside London Cogeneration in responding to a Directed Dispatch Order (LT), the OPA is prepared to establish a standing credit support guarantee in favour of the supplier of gas to Countryside London Cogeneration. In addition, the OPA has established a provisional process for a Directed Dispatch Order (LT) which allows Countryside London Cogeneration to obtain price quotes for gas which are then provided to the OPA for their consideration and which if acceptable, and provided that Countryside London Cogeneration is then able to secure the required physical or financial gas supply, becomes the Gas Price (LT) applicable for such Directed Dispatch Order (LT). In short, the gas exposure for Countryside London Cogeneration is covered by the OPA in respect of a Directed Dispatch Order (LT). Where Countryside London Cogeneration is not under a *Directed Dispatch* Order or such order is cancelled, Countryside London Cogeneration is considered to be in Deemed Dispatch. In the event of such cancellation, the OPA will cover Countryside London Cogeneration for any losses incurred on the resale of gas previously bought to fill a Directed Dispatch order.

The CHP Contract contains an extensive force majeure provision which permits Countryside London Cogeneration to declare force majeure in a wide variety of traditional circumstances (Act of God) and for a Host Facility Force Majeure. In addition, the force majeure provision provides:

> Declaring Force Majeure does not excuse or relieve a party from performing or complying with its payment obligations;
>
> If the event of Force Majeure caused by Countryside London Cogeneration not to achieve a Milestone Event or meet the relevant Milestone Date, or to not achieve Commercial Operation (within one (1) year after the Commercial Operation Milestone Date) then the Milestone Date shall be extended.
>
> If the event of Force Majeure delays the Commercial Operation Date by more than three hundred and sixty-five (365) days after the original Milestone Date, Countryside London Cogeneration may at its sole option terminate the CHP Contract upon notice to the OPA without any cost or payments of any kind to either Party and all security will be returned.
>
> If the event of Force Majeure delays Commercial Operation Date by more than twenty-four (24) months after the original Milestone Date either Party may terminate the CHP Contract upon notice to

the other Party without any cost or payments of any kind to either Party and all security will be returned.

If by reason of Force Majeure, Countryside London Cogeneration is unable to perform or comply with its obligations for more than thirty-six (36) months in any sixty (60) month period then either Party may terminate the CHP Contract without any costs or payments to either Party (except up to date of termination) and security will be returned.

The OPA has established a threshold of 80% of the Contract Capacity as the minimum threshold that the London Cogen Facility needs to meet failing which (after a Further Capacity Check Test) it is an Event of Default with no cure period. Each Capacity Test Check is conducted over a four hour period designated by Countryside London Cogeneration and approved by the OPA using protocols proposed by Countryside London Cogeneration and approved by the OPA. If it is between 80% - 100% the Capacity Reduction Factor is affected (used in the calculation of Total Monthly Fixed Capacity Payment) but there is no Event of Default although a Final Capacity Check Test is then required no earlier than one (1) month or no later than one (1) year after the previous Further Capacity Check Test. Failure to test is an Event of Default and failure to pass is also considered an Event of Default.

The OPA has the right to assign the CHP Contract without the consent of the Supplier but the OPA does remain liable to the Supplier for remedying any payment defaults under the CHP Contract and does remain liable for any obligations and liabilities of the assignee from any Buyer Event of Default

The CHP Contract maintains the requirement that no assignment or change of control will be permitted until the 3rd anniversary of the Commercial Operation Date.
There are events of default for both Countryside London Cogeneration and the OPA. These additional events of default include: a cross-default provision (default by Supplier of financial obligations to a third party); failure to meet the Commercial Operation Date; failure to meet the Availability requirements; Capacity Check Requirement failures; and Performance Security failures subject to cure provisions.

For certain Countryside London Cogeneration events of default, the OPA is entitled to levy a performance assessment set-off, as liquidated damages equal to three (3) times the average Contingent Support Payment payable to Countryside London Cogeneration for the most recent twelve (12) months where there has been three (3) or more Countryside London Cogeneration events of default within a contract year regardless of whether such events had been subsequently cured.

Fuel

The primary fuel for the London Cogen Facility shall be natural gas which is the London District Energy System's current fuel. The gas is expected to be delivered directly from the local distribution network operated by Union Gas, the London District Energy System's current gas transportation company. Countryside District Energy has commenced discussions on Countryside London Cogeneration's behalf with Union Gas, the London District Energy System's existing gas transportation company for a non-interruptible fuel transportation arrangement with an element of "T1" storage in order to allow both physical and financial management of the gas supply needs. Union Gas has verified its ability to deliver the quantity required for operation of the London Cogen Facility through the existing pipeline. Countryside District Energy and Union Gas have identified and priced certain infrastructure improvements which will be made to accommodate the increased supply.

Countryside District Energy and Countryside London Cogeneration have signed a non-binding letter of intent respecting a firm non-interruptible fuel supply arrangement with Integrys Energy Services of Canada Corp. (formerly WPS Energy Services of Canada Corp.), its existing supplier, to acquire the fuel required for the London Cogen Facility correlated to Dawn Index pricing. There is no assurance that the parties will enter into a binding fuel supply arrangement. Countryside District Energy will supply fuel to Countryside London Cogeneration at Countryside District Energy's cost as set out in the Operations and Maintenance Agreement described below.

EPC Contract

Meccon London, Inc. ("Meccon") and Countryside London Cogeneration have executed a "Design Procure and Construct (EPC) Agreement" ("EPC Contract") to design, procure and construct and deliver a fully operational 19 MW Cogeneration Plant in conformance with approved plans, manufacturers' specifications and the CHP Contract. Meccon's obligations under the CHP Contract are guaranteed by its parent Meccon Industries, Inc. The EPC Contract provides for a Guaranteed Maximum Price of $25,280,000 ("GMP") inclusive of the estimated cost of the work, Meccon's fee and payment and performance bond premiums. GMP is subject to adjustment for change orders agreed to by the parties. In the event the actual cost of the work exceeds the GMP, Meccon will be responsible for such excess and it will not receive a contractor's fee. In the event the total of the actual cost of the work, Meccon's fee and the payment and performance bond premiums is below the GMP, Countryside London Cogeneration and Meccon will share in such savings on a 60/40 basis. The EPC Contract requires that Meccon achieve substantial completion by April 1, 2008 and commercial operation by June 1, 2008. These dates are subject to adjustments for force majeure in a manner consistent with the force majeure provision in the CHP Contract. Under certain circumstances, if Meccon fails to meet the commercial operation date, it will be liable for liquidated damages of $1,800 per day (which is substantially equivalent to the liquidated damages that Countryside London Cogeneration would be liable for under the CHP Contract). Meccon's obligations under the EPC Contract are backed by a performance bond and a payment bond, each in the amount of the GMP. Meccon and Countryside District Energy will enter into a separate contract respecting the design and construction of certain capital improvements to increase the capacity of the district energy system. The cost of such items is included in the total project budget but is outside the scope of the EPC Contract which relates only to the London Cogen Facility.

Energy Services Agreement

Countryside London Cogeneration and Countryside District Energy have entered into an Energy Services Agreement ("ESA") under which Countryside London Cogeneration will sell steam generated by the London Cogen Facility to Countryside District Energy for use in the London District Energy System. While the parties are affiliated, the ESA contains arms-length terms. The term of the ESA is 20 years commencing on the commercial operation date under the CHP Contract and may be terminated by either party if the CHP Contract, the O&M Agreement (described below), or the Lease (described below) are terminated. The steam charge shall reflect Countryside District Energy's avoided cost of producing the steam. During the term of the ESA, Countryside London Cogeneration will supply Countryside District Energy's steam requirements up to a defined capacity and will not sell steam to any other party so long as Countryside District Energy can accept the steam. Countryside London Cogeneration will not provide steam when the London Cogen Facility is not in operation. The ESA contains other terms and conditions, including metering, billing, events of default and force majeure (consistent with CHP Contract) which are standard for this type of agreement.

Site Lease

Countryside District Energy will enter into a Site Lease with Countryside London Cogeneration for a portion of Countryside District Energy's existing site (approximately 0.5 acres) on which the London Cogen Facility will be located. Except as noted below, the Site Lease contains arm's length terms. The term of the Site Lease shall continue until the CHP Contract is terminated or expires unless the Lease is earlier terminated due to an event of default. While the ESA is in effect the rent would be nominal, because the economics between Countryside District Energy and Countryside London Cogeneration will be dealt with in the ESA and the O&M Agreement described below. If the ESA is terminated before the Site Lease terminates, the rent will be re-set at fair market value. Countryside London Cogeneration will also be responsible for any incremental property and business taxes attributable to its property and operations. The Site Lease contains other standard provisions such as permitted use, insurance, condemnation, damage and destruction, construction, waste, liens, installation and removal of equipment, events of default, remedies, assignment and force majeure.

O&M Agreement

Countryside District Energy will enter into an Operations and Maintenance Agreement ("O&M Agreement") with Countryside London Cogeneration to provide operations and maintenance services for the new cogeneration project. The O&M Agreement will cover project, operations, maintenance and repair (exclusive of major repairs). The term shall commence on the date the CHP Contract becomes binding and shall remain in effect so long as the CHP Contract remains in effect provided that either party may terminate the

O&M Agreement if the ESA is terminated. Further Countryside London Cogeneration may terminate for convenience. Countryside London Cogeneration will reimburse Countryside District Energy for the cost of Countryside District Energy employees who perform operations for the benefit of Countryside London Cogeneration based on the time spent providing such services (or an agreed upfront allocation of such time). Countryside District Energy shall operate the project in accordance with an annual operations budget and annual operating plan agreed to by Countryside District Energy and Countryside London Cogeneration each year. The O&M Agreement also provides that Countryside District Energy shall provide gas fuel to Countryside London Cogeneration and Countryside London Cogeneration will reimburse Countryside District Energy for its costs. The O&M Agreement contains other standard provisions relating to defaults, indemnities, covenants and except as noted above, contains arms-length terms.

Third Party Approvals and Permits

Countryside District Energy has received approval from the City of London for a minor zoning variance that will permit the construction of the London Cogen Facility subject to site plan approval and issuance of a building permit. Countryside London Cogeneration has received a Certificate of Acceptance from the Ministry of the Environment relating to air emissions and noise abatement which will regulate the London Cogen Facility's operations along with other applicable environmental laws and rules. Countryside London Cogeneration is pursuing a generator's license from the Ontario Energy Board. Countryside London Cogeneration has applied for a Connection Application with London Hydro, the local distribution company and will apply for a connection with the IESO. Countryside London Cogeneration's engineers have conducted a preliminary interconnection study, during which they met with London Hydro, and concluded that such interconnection is feasible.

THE RENEWABLE ENERGY PROJECTS

Background

On May 1, 2001, the predecessor of USEB, Zahren Alternative Power Corporation, was acquired by USEY (54.26%) and an indirect subsidiary of Cinergy (45.74%). On November 28, 2006, USEY acquired the minority interest in USEB from an indirect subsidiary of Duke Energy. USEB owns 100% of the Renewable Energy Projects located outside of Illinois and 50% of those located in Illinois, of which Illinois Landfill, successor to AJG, owns the remainder.

USEY is a vertically integrated energy company. Its principal businesses are natural gas exploration, production and transportation, natural gas-fired power generation and sales and green and renewable energy development, particularly landfill gas-to-energy. USEY owns, operates and/or has financed 23 green energy, district energy and cogeneration projects in North America and the United Kingdom with a total of approximately 94 MW of electric generation capacity as well as licenses to natural gas fields in the United Kingdom .

USEB Loans

On closing of the Initial Offering, Countryside Canada purchased certain Existing Loans from the then current lenders to USEB and various affiliates of USEB, including John Hancock Financial Services, Inc. and certain of its affiliates, GESF Energy Capital LLC and AJG, for a cash purchase price equal to 100% of the principal amount outstanding under the Existing Loans on the closing date of the Offering. USEB paid all accrued unpaid interest on the Existing Loans and made an additional payment to John Hancock Financial Services, Inc. and its affiliates and GESF Energy Capital LLC in connection with the purchase.

Upon acquisition of the Existing Loans, Countryside Canada made Additional Advances to USEB and Countryside Canada and USEB and amended the Existing Loans to include the Additional Advances and otherwise give effect to the terms set forth in the amendment to the note purchase agreement governing the USEB Loans (the "USEB Loan Agreement"). Including the Additional Advances, the USEB Loans were for an initial principal amount of CDN $107 million.

The USEB Loans consisted of two loans, a loan in the approximate principal amount as of the closing of the Initial Offering, of $89.8 million (the "USEB A Loan") and a loan in the approximate principal amount, as of the closing of the Initial Offering, of $17.2 million (the "USEB B Loan"). USEB was the borrower on both USEB Loans. The USEB Entities that own the USEB Operating Assets guaranteed both USEB Loans.

As security for the USEB Loans, Countryside Canada had a first ranking lien on all of USEB's assets except the Excluded Assets, and substantially all of the USEB Operating Assets not directly held by USEB secure the guarantees.

Yankee Energy Services Company ("YESCO") retained its second lien on the equity interests in and assets of the USEB Entities that own the assets of and equity interests in the Countryside, Morris and Brookhaven projects securing its US$4.7 million vendor's note (the "YESCO Note") which is subordinated to such projects' guarantees of the USEB B Loan but is senior to such guarantors' unsecured guarantees of the USEB A Loan. USEB provided an unsecured guarantee of the YESCO Note.

The interest rate on the USEB Loans was 11.0% per annum and principal and interest is paid monthly. The USEB Loans had a maturity date of 15 years from April 8, 2004, subject to mandatory prepayment provisions and prepayment at the election of the lender after 10 years. For a more detailed description of the USEB Loan see the Fund's Annual Information Form for the year ended December 31, 2005 (the "2005 AIF")-" The Renewable Energy Projects- USEB Loans (pp 32 -34)".

USEB Royalty Interest

On closing of the Initial Offering, the Fund, through Countryside Canada, acquired the USEB Royalty Interest for US$6,000,000 ($7,884,000). The USEB Royalty Interest entitled Countryside Canada to receive an annual amount (the "Royalty") from USEB that was determined by reference to, and limited by, USEB Distributable Cash Flow (as defined in the USEB Royalty Agreement). The USEB Royalty Interest was to be convertible, subject to certain regulatory conditions, at any time on or after the 20th anniversary of the closing of the Initial Offering on April 8, 2004, or in the event of the prepayment in full of the USEB Loans, on or after the date of such prepayment, into non-voting common shares of USEB (the "Equity Interest"), representing 49% of the common shares of USEB outstanding at the time of conversion. Upon conversion of the USEB Royalty Interest, Countryside Canada's right to receive the Royalty was to terminate. The amount of the Royalty payable to Countryside Canada depended upon whether the USEB Royalty Interest became convertible. For each fiscal quarter prior to that in which the USEB Royalty Interest became convertible, the amount of the Royalty payable to Countryside Canada was to equal to 7% of the USEB Distributable Cash Flow plus an additional percentage of USEB Distributable Cash Flow equal to 1.8% of the USEB Revenues (defined in the USEB Royalty Agreement), but in any event, the Royalty payment was to be subject to a Distribution Cap (defined in the USEB Royalty Agreement). After the USEB Royalty Interest became convertible, but remained unconverted, the Royalty was to be equal to 49% of USEB Distributable Cash Flow, subject to the Distribution Cap.

The USEB Royalty Interest was to terminate upon the liquidation of the USEB Operating Assets or a sale of substantially all of the assets of the USEB Operating Assets (such events, together with the refinancing of the USEB Loans, a "Capital Event"). Upon the occurrence of a Capital Event, Countryside Canada was to become entitled to receive, subject to the Distribution Cap, US$6 million (the "Return Amount") and 49% of the Net Residual Proceeds as defined in the USEB Royalty Agreement. For a more detailed description of the USEB Royalty Interest, see the 2005 AIF-"The Renewable Energy Projects-USEB Royalty Interest (pp 35 -37)".

USEB Bankruptcy

On November 29, 2006 USEB and various subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York.

Prior to the filing by USEB, USEB had failed to provide various financial statements required under the USEB Loans. Further, the Fund had been in discussions with USEB concerning the restructuring of the USEB Loans in light of the fact that USEB might face cash flow problems in the first quarter of 2007. Such discussions were unsuccessful. Instead, USEB filed for reorganization in order "to unlock shareholder value" according to its press release. It alleged in the bankruptcy case, among other things, that its business was operationally sound and solvent but that its current capital structure was impaired by a "flawed and unjustifiably onerous" loan agreement with the Fund that, absent a restructuring, would cause USEB to become insolvent.

The Fund strongly disagreed with USEB's allegations with respect to the Fund, and the USEB Loans.

At the urging of the Bankruptcy Court, the Fund, USEY and USEB participated in a mediation on January 12 and 13, 2007 respecting the outstanding disputes between them.

Through the mediation, the Fund, USEY, USEB and the Fund's executives, in their individual capacity, reached agreement in principle on the USEB Settlement. The USEB Settlement is formalized in (i) a Settlement Agreement by and among USEY, USEB and certain of its affiliates (collectively the "US Energy Parties"), the Fund, Countryside Canada, Countryside US Power and Countryside Ventures LLC (collectively "Countryside"), Goran Mornhed, Edward Campana and Allen Rothman (the "Individuals" and together with Countryside the "Countryside Parties") (the "USEB Settlement Agreement") and (ii) a Stipulation and Final Order (I) Authorizing Debtors To Use Certain Cash Collateral And (II) Granting Adequate Protection To Countryside Canada Power Inc. executed by USEB and its debtor affiliates, Countryside Canada and the Official Committee of Unsecured Creditors (the "Final Cash Collateral Order") . The USEB Settlement Agreement and Final Cash Collateral Order were approved in principle by the Bankruptcy Court on February 1, 2007 and formally approved by order of the Bankruptcy Court on February 16, 2007 over the objection of the State of Illinois (the "Approval Order"). The Approval Order and the Final Cash Collateral Order became final and non-appealable on February 26, 2007 and the Settlement Agreement became effective on March 7, 2007. The Final Cash Collateral Order became effective immediately.

The following summary of certain terms of the USEB Settlement is subject to and qualified in its entirety by reference, to all the terms of the Settlement Agreement and the Final Cash Collateral Order.

The USEB Settlement settles Countryside Canada's claims for all amounts claimed under the USEB Loan (including, without limitation, principal, pre and post-petition interest, loan breakage fees, expenses and indemnity) by allowance of a secured claim against USEB and its debtor affiliates of US$99,000,000 (or approximately $116,000,000 at the then current exchange rate) in the USEB Bankruptcy (the "Allowed Secured Claim"). The Allowed Secured Claim continues to be secured by a first lien on substantially all of the assets of USEB and its subsidiaries, which may be enforced through the enforcement remedies provided in the USEB Loans.

The USEB Settlement provides for installment cash payments on the Allowed Secured Claim of US$3,000,000 on or before January 31, 2007 (which was paid in cash on January 31, 2007), US$30,000,000 on or before March 31, 2007 (which was substantially paid in cash over a period from March 9-13, 2007), and the remaining principal balance and accrued unpaid interest on or before maturity at May 31, 2007. USEB may pay up to US$2 million in USEY common stock which is registered or otherwise freely tradable with the number of shares to be calculated based on the weighted average closing price on the five trading days preceding the payment.

Outstanding principal amounts under the Allowed Secured Claim bear cash interest at a rate of 10% per annum from February 1, 2007, payable monthly in U.S. dollars. Upon any default in timely payment of principal or interest, the unpaid balance of the Allowed Secured Claim shall bear 12% default interest from the date of the last payment until such default has been cured or waived.

The USEB Allowed Claim may be prepaid at any time prior to May 31, 2007 without penalty. The USEB Allowed Claim must be paid from the proceeds of any Debtor in Possession "DIP" financing provided that no DIP financing shall prime or be parri-passu with the liens securing the Allowed Secured Claim.

The USEY Parties on the one hand and the Countryside Parties on the other hand exchanged general releases covering all claims (as defined in the Settlement Agreement) arising before the Effective Date of the Settlement Agreement with certain exceptions including claims arising from the Allowed Senior Claim, the Settlement Agreement, and the Final Cash Collateral. Among other things, in such releases the USEY Parties released all claims against the Countryside Parties alleging any improprieties respecting the USEB Loans, the Countryside Parties released USEB from all claims relating to the USEB Royalty and all the Parties released each other from all claims relating to the Development Agreement.

On March 22, USEY announced that USEB reached an agreement in principle with the State of Illinois resolving outstanding issues between the parties in the bankruptcy proceedings. According to USEY, among other things, the State of Illinois has agreed not to pursue repayment of approximately US$63 million in incentives in return for a payment of US$5 million on the effective date of USEB's plan of reorganization (which has not yet been filed) and no later than May 31, 2007. In addition according to USEY's announcement, USEB's Illinois-based projects will withdraw from the Illinois retail rate incentive program effective May 31, 2007. Such agreement is subject to the approval of the Bankruptcy Court. The Manager believes that USEB's agreement with the State of Illinois, if approved, will improve USEB's chances of consummating an exit financing which would satisfy the Allowed Secured Claim.

USEB Operating Profile

If USEB pays the Allowed Severed Claim in full, the Fund should no longer be affected by the operations of USEB. Until such time, however, USEB's operations will affect USEB's ability to consummate an exit financing to pay the Fund's Allowed Secured

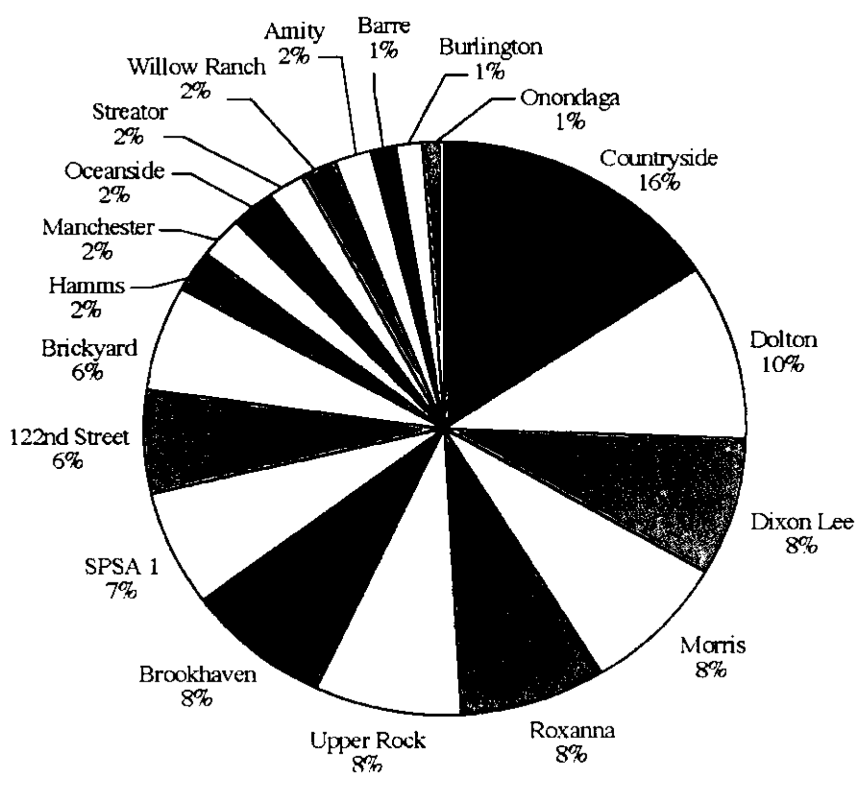
Claim or the Fund's ability to realize full value on the Allowed Secured Claim if it is not paid in accordance with its terms.

The Renewable Energy Projects currently have approximately 52MW of electric generation capacity. Eighteen of the 23 Renewable Energy Projects have contracts with local electric utilities for the sale of electrical output. The Brookhaven project leases electric generation equipment to a third party, which in turn has a contract to sell the output to an electric utility.

In addition, USEB receives payments under notes issued to subsidiaries of Cinergy and AJG ("Gasco Notes") in connection with the sale of its ownership interests in 16 Gascos that qualify for Section 29 tax credits. These payments are scheduled to end in 2007. The loss of this revenue stream in 2007 is expected to be primarily offset by increased electricity and boiler fuel production volumes from planned expansions of the Renewable Energy Projects.

The Renewable Energy Projects are located across nine states in the U.S. with a majority of power sales to electric utilities in the State of Illinois. The Renewable Energy Projects are able to capitalize on regional opportunities as they relate to the sale of electricity and government incentive programs.

SUMMARY OF RENEWABLE ENERGY PROJECTS(1)
ELECTRIC GENERATION CAPACITY (MW) 2005



(1) Excludes those Renewable Energy Projects whose production output is boiler fuel.

All of the Renewable Energy Projects located in Illinois receive an incentive under the Rate Incentive Program for the first 10 years of their commercial operation. The PPA/Retail Rate Expiry listed in the table below reflects the date of expiry of the entitlement to receive this incentive for each Renewable Energy Project located in Illinois and the date of expiry of the PPAs for those Renewable Energy Projects located outside of Illinois. Under the proposed settlement between USEB and the state of Illinois, the Illinois-based Renewal Energy Project's entitlements to receive the incentive will terminate May 31, 2007. Subsequent to the expiry of a project's entitlement to receive incentives or its PPA, as the case may be, the relevant electric utility will remain obligated to purchase the project's electrical output at the utility's Avoided Cost for so long as the project produces electricity and maintains its status as a QF under the FPA and meets certain other state law requirements. Alternatively, USEB may choose to sell the electrical output of the Renewable Energy Projects into the Green Power Market or the electricity wholesale market. USEB may also sell renewable energy credits and GHG emission credits separately from the sale of electricity.

Summary of the Renewable Energy Projects

Set out below is a listing of the Renewable Energy Projects and their key characteristics As of December 31, 2005, the Manager believes that such key characteristics have not changed materially since that date except that pursuant to the proposed settlement between USEB and the State of Illinois, the retail rate expiry for the Illinois based renewable energy projects will be May 31, 2007 if such settlement is consummated.

RENEWABLE ENERGY PROJECTS SUMMARY 2005

Project	State	Project Output	MW	PPA/Retail Rate Expiry	Off-Taker(s)	Gas Rights Agreement Expiry	Site Lease Expiry	Landfill Status
Countryside	IL	Electricity	8.0	2011	Commonwealth Edison	(1)	(1)	Open
Dolton	IL	Electricity	5.0	2008	Commonwealth Edison	2016(2)	2016(2)(3)	Open
Dixon Lee	IL	Electricity	4.0	2009	Commonwealth Edison	2017(2)	2017(2)	Open
Morris	IL	Electricity	4.0	2011	Commonwealth Edison	2018(4)	2018(4)(5)	Open
Roxanna	IL	Electricity	4.0	2009	Illinois Power	N/A	2018(2)	Open
Upper Rock	IL	Electricity	4.0	2010	MidAmerican Energy	2017(2)	2029	Open
SPSA I	VA	Electricity	3.3	2014	Virginia Power	2011(6)	2011(6)	Open
122nd Street	IL	Electricity	3.0	2008	Commonwealth Edison	2016(2)	2016(2)	Closed
Brickyard	IL	Electricity	3.0	2009	Illinois Power	2017(2)	2017(2)	Open

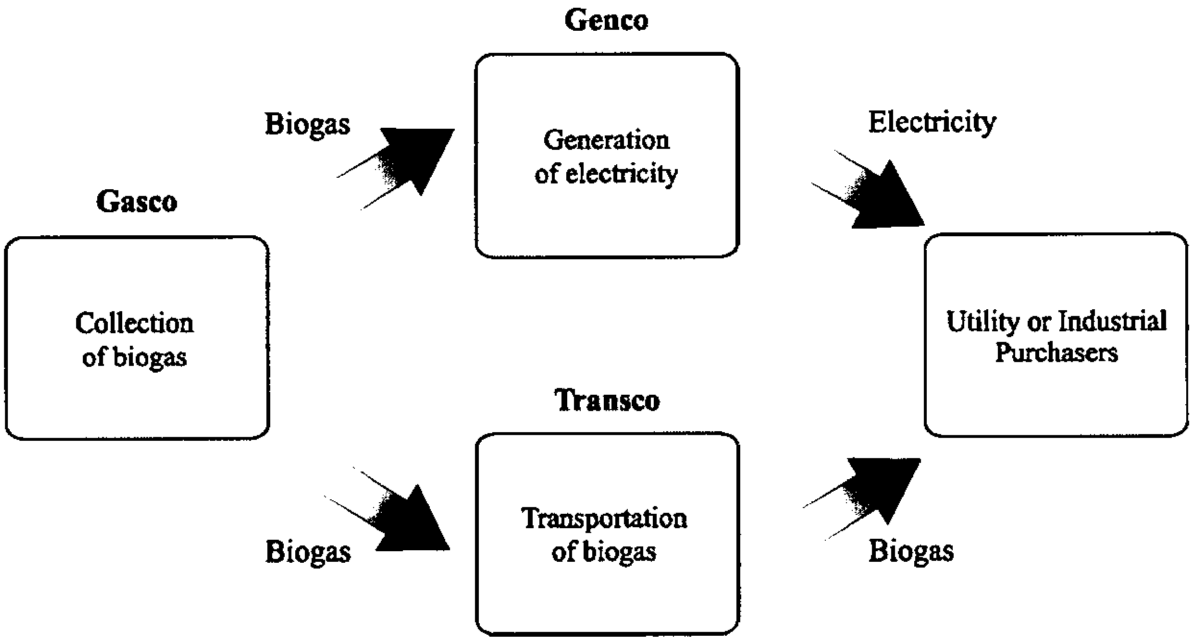
Project	State	Project Output	MW	PPA/Retail Rate Expiry	Off-Taker(s)	Gas Rights Agreement Expiry	Site Lease Expiry	Landfill Status
Hamms	NJ	Electricity	1.2	2010	GPU/First Energy	2006(7) 2016(2)	2006(7)	Closed Open
Manchester	NH	Electricity	1.2	Ongoing(8)	New Hampshire Public Service	2004(9)	2004(9)	Closed
Oceanside	NY	Electricity	1.2	2006	Long Island Power Authority	2004(7)	2004(7)	Closed
Streator	IL	Electricity	1.0	2009	Commonwealth Edison	2017(2)	2017(2)	Open
Willow Ranch	IL	Electricity	1.0	2007	Commonwealth Edison	2016(2)	2016(2)	Closed
Amity	PA	Electricity	1.0	2007(12)	Penn Power & Light	2006(7)	2006(7)	Closed
Barre	MA	Electricity	1.0	2006(10)	Dominion Power	2015	2015	Closed
Burlington	VT	Electricity	0.7	2006(2)	Burlington Electric Dept.	2006(2)	2006(2)	Closed
Onondaga	NY	Electricity	0.6	2007(13)	Niagara Mohawk	1999(7)	1999(7)	Closed
Cape May	NJ	Boiler Fuel	N/A	2009(11)	State of New Jersey	2011	2011	Open
SPSA II	VA	Boiler Fuel	N/A	2011(12)	CIBA Specialty Chemical	2011	N/A(13)	Open
Tucson	AZ	Boiler Fuel	N/A	2011(12)	Tucson Electric Power	2017	N/A(13)	Open
Brookhaven	NY	Electricity	4.0	2007	Wehran Energy Corp.	N/A(14)	N/A(14)	Closed

(1) The term of such agreements substantially exceeds the term of the USEB Loan.
(2) Subject to two five-year extension terms at USEB's option.
(3) A portion of the site is owned and a portion is leased.
(4) Subject to three five-year extension terms at USEB's option.
(5) The gas rights agreement at the Morris project provides the project's Genco with a site lease. A stand alone site lease is in final stages of being formalized with the landfill owner.
(6) May be extended for one or more five year terms by mutual agreement.
(7) The agreement automatically renews so long as biogas is produced in commercially reasonable quantities.
(8) Continues until terminated by USEB.
(9) Agreement may be extended for up to 10 years upon mutual consent.
(10) May be terminated by off-taker on one year's notice.
(11) Facilities operations agreement under which USEB operates the gas collection system and transmission pipeline to the off-taker and in consideration receives a fee.
(12) Gas purchase agreement.
(13) These Transcos have no facilities located at the site. A transmission pipeline runs from the Gasco directly to the end users.
(14) The Brookhaven project is structured as an equipment lease under which a subsidiary of USEB owns the power generating equipment and receives a fee to operate such equipment.

Commercial Structure of the Renewable Energy Projects

The Renewable Energy Projects may incorporate up to three separate legal entities as illustrated in the following diagram and described below:

TYPICAL RENEWABLE ENERGY PROJECT COMMERCIAL STRUCTURE



Gasco

Gascos are the legal entities that typically own the biogas extraction rights and collection systems and collect and sell the biogas to a Genco and/or a Transco, as the case may be, under long-term, fixed-rate contracts. Gascos are typically structured as limited partnerships whereby the beneficiaries of the Section 29 tax credits own a 99% limited partnership interest in the Gasco and USEB owns a 1% general partnership interest or less in the Gasco. The limited partnership interests are held by AJG and USEY. Countryside Canada does not own any interest in such limited partnership interests through the Allowed Secured Claim except an indirect interest in debt service payments received from such third parties by USEB under the Gasco Notes. In the cases of the Roxanna and Brookhaven projects, USEB does not own an interest in the relevant Gascos.

The Gencos typically provide the Gascos with a portion of the electricity they generate to power their gas collection systems and, in addition, provide operating and maintenance services to the Gascos. The total revenues received by the Gascos for the sale of biogas generally equates to the total cost of the Gencos providing the electricity and operating and maintenance services to the Gascos.

Genco

Gencos are the legal entities that typically own the power generating equipment, purchase the biogas from a Gasco and sell the electricity it generates to an electric utility or industrial user under long-term contracts. The Renewable Energy Projects incorporate 19

Gencos that are wholly-owned subsidiaries of USEB, except for the Illinois-based projects which are owned 50% by USEB and 50% by Illinois Landfill. Gencos typically lease a portion of a landfill site from an independent third party landfill owner.

Transco

Transcos are the legal entities that typically own the gas transportation equipment and purchase biogas from a Gasco to transport and sell to a third party as boiler fuel under long-term contracts. The Renewable Energy Projects include three Transcos which are all wholly-owned subsidiaries of USEB.

Pricing Structure

Illinois QSWEF Pricing Structure

The State of Illinois established the Rate Incentive Program to encourage, among other things, the proper disposal of waste and, where economically and technically feasible, the efficient use of the products or by-products generated as a result of its disposal. Since their inception, the Illinois-based Renewable Energy Projects have participated in the Rate Incentive Program as QSWEF's. Under the Rate Incentive Program, QSWEFs sell electricity at the Gross Contract Rate for the first 10 years of their commercial operation. The Gross Contract Rate is calculated annually by the electric utility and equals the average amount per kWh paid by local government entities for electricity in the jurisdiction in which the QSWEF is located (with certain exceptions). The difference between the Gross Contract Rate and the electric utility's Avoided Cost equals the QSWEF's incentive. A QSWEF must begin to repay the incentive no later than the earlier of the date the QSWEF has paid or otherwise satisfied in full the capital costs or indebtedness incurred in developing its facility and 10 years after the date the QSWEF began commercial operation. The incentive, without interest, must be entirely repaid by the QSWEF upon the earlier of 20 years after the QSWEF began commercial operation and the end of the QSWEF's actual useful life and is required to be made under a schedule to be determined by the ICC based on the manner in which the local utility claimed the relevant tax credits.. See "— ICC Rate Incentive Program and ICC Reimbursement Account".

In the USEB Bankruptcy, the State of Illinois moved to lift the automatic stay in order to commence administrative proceedings to revoke the QSWEF status of USEB's Illinois-based Renewable Energy Projects. While such motion was pending, USEB, the QSWEF's and the State of Illinois announced they had reached a settlement respecting their outstanding issues under which, among other things, USEB's Illinois-based Renewable Energy Projects' participation in the Rate Incentive Program will terminate effective May 31, 2007 and the State of Illinois will have an allowed unsecured claim of US$5.3 million in respect of the USEB's Illinois-based Renewable Energy Projects' liability to repay the incentive. Such Settlement is subject to Bankruptcy Court approval.

ICC Rate Incentive Program and ICC Reimbursement Account

To assist in providing sufficient funds for reimbursement of the incentive, each Illinois-based Renewable Energy Project stated, under the orders that the ICC issued to establish and/or confirm its status as a QSWEF (the "ICC Orders"), it would establish an ICC Reimbursement Account which it has funded a portion of the amount of the incentive it receives. The ICC Orders have no specific requirements for the amount of funds that need to be deposited in the ICC Reimbursement Account for repayment of the incentive or for the type of investments that are appropriate for the ICC Reimbursement Account. Each Illinois-based Renewable Energy Project invested the funds held in a ICC Reimbursement Account in a balanced portfolio of fixed income, equity and other investments managed by a professional advisor. See "Risk Factors — Risks Related to the Business — QSWEF Status of USEB's Illinois-based Biogas Project" and "Risk Factors — Risks Related to the Business — ICC Repayment Liability of USEB's Illinois-based Renewable Energy Project".

Pursuant to the settlement agreement between the Fund and USEB, during the period March 9-13, 2007 USEB funded a US$30 million payment under the USEB Settlement with substantially all of the funds in the Illinois Reimbursement Account.

Although the Rate Incentive Program for each of the Illinois-based Renewable Energy Projects terminates 10 years after the commencement of commercial operation (or may terminate on May 31, 2007 under the proposed settlement between USEB and the State of Illinois). The local electric utility is obligated to purchase the electrical output from such Renewable Energy Project at the utility's Avoided Cost for so long as the Renewable Energy Project qualifies as a QF and satisfies Illinois laws. This obligation arises under requirements of PURPA, and Part 430, *Purchase and Sale of Electrical Energy from Cogeneration and Small Power Production Facilities* of the *Illinois Administrative Code*.

Green Power Market and Pricing

After expiration of the 10-year period over which the Illinois-based Renewable Energy Projects participate in the Rate Incentive Program (or upon earlier termination of such participation under the settlement between USEB and the State of Illinois), and after expiration of the PPAs for the non-Illinois-based Renewable Energy Projects, USEB anticipates that it will sell the power generated by the Renewable Energy Projects into the Green Power Market, if economically attractive.

The use of power derived from alternative sources has been mandated in several states in the United States, in addition to being discussed at a federal level. Such states, including Illinois, have incorporated, or are in the process of incorporating or considering the incorporation of, Renewable Portfolio Standards. These standards require that a certain percentage of power generated be derived from a renewable fuel source. In Ontario, the

Electricity Conservation and Supply Task Force, which was established in June 2003 and released its report on January 14, 2004, has recommended that Ontario implement Renewable Portfolio Standards and concluded that renewable energy generation will be a vital part of Ontario's future electricity supply mix. The mandate for such standards stems from the objective of reducing the use of fossil fuels, reducing the reliance on foreign energy sources and increasing the production of clean energy.

In those jurisdictions where the Renewable Portfolio Standards exist, Green Power Markets may develop and rates for green power may increase to a level that may result in green power generation reaching the level set by the Renewable Portfolio Standards. Such levels typically involve a price premium on electricity generated reflecting the total cost (including capital) of producing such power. In addition, without state-mandated Renewable Portfolio Standards, it has been demonstrated that there is a segment of the general public that has a preference for electricity generated from green power, and is willing to pay a premium for such power.

Section 29 Tax Credits

Since the development of the Renewable Energy Projects, USEB has sold predominantly all of its ownership interests in the Gascos to either Cinergy or AJG.

An indirect subsidiary of Cinergy (now Duke Energy) purchased USEB's ownership interests in the Countryside, Morris and Brown County Gascos. Consideration for the purchase was in the form of: (i) an up-front down payment; (ii) a fixed note with specified principal and interest payments; and (iii) a contingent note whose payments are based upon the amount of MMBtus sold by the Gascos to the Gencos. On November 28, 2006, a USEY subsidiary assumed the obligations under such notes from an indirect subsidiary of Duke Energy in exchange for such subsidiary's shares in USEB. USEB has agreed to indemnify the payor under the notes for certain losses suffered in the event that certain tax-related representations and warranties made by USEB are inaccurate.

AJG purchased the ownership interests in other Renewable Energy Projects' Gascos, which generate Section 29 tax credits. Consideration from AJG to USEB was in the form of: (i) an up-front down payment; and (ii) a contingent note whose payment is based upon the amount of MMBtus sold by the Gascos to the Gencos. AJG subsequently sold certain of such ownership interests to a subsidiary of American International Group. USEB has agreed to indemnify AJG for certain losses suffered in the event that certain tax-related representations and warranties made by USEB are inaccurate.

The ability of a project to receive Section 29 tax credits depends on the placed-in-service date of the facility. Section 29 tax credits for the Gascos at 14 Renewable Energy Projects are currently available annually until December 31, 2007, based on an in-service date of on or before June 30, 1998. These projects include Brickyard, Cape May, Countryside, Dixon Lee, Dolton, Hamms, Manchester, Morris, 122nd Street, SPSA (I and II), Streator, Upper Rock, Tucson and Willow Ranch. Renewable Energy Projects with in-service dates prior to 1993 qualified for tax credits only through 2002. These projects include Amity, Burlington, Oceanside and Onondaga. USEB also owns two developmental sites where the Gascos generate tax credits, and receives revenues from four other Gascos where the sites themselves are owned and operated by third parties. In 2005, these four sites generated revenues of approximately US$93,000. USEB has two generating facilities, Brookhaven and Roxanna, whose Gascos were not owned by USEB and therefore generate no revenue for USEB from Section 29 tax credits.

USEB thus receives a cash flow stream in connection with the sale of its Gasco interests. Since Section 29 requires that a sales transaction take place between unrelated parties, the Genco/Gasco structure was created. Each Renewable Energy Project (except Brookhaven and Roxanna), regardless of whether it is a Genco or Transco, is affiliated with a Gasco entity that has generated and/or continues to generate Section 29 tax credits for the benefit of the Gasco entity's owners. Neither USEB nor any of the Gascos has obtained a ruling from the IRS confirming that Gascos generate Section 29 credits. All of the Renewable Energy Projects currently in operation (except for the Roxanna and Brookhaven projects) have provided or continue to provide economic benefits to USEB through the sale of Section 29 tax credits to Cinergy, AJG and American International Group.

Through December 31, 2007, Code Section 29 has a phase out provision that is triggered when the "Market Wellhead Price" of domestic crude oil reaches certain "Phase-out Prices" as determined by the IRS. The IRS will not publish the Phase-out Prices for calendar year 2006 until April or May 2007. On average, estimated Market Wellhead Prices in 2006 exceeded the price at which it is estimated the Phase out will be triggered. Therefore, it is estimated that the Phase out will be triggered to some extent in 2006 although whether the Phase-out will in fact been triggered and, if so, the extent of such Phase-out will not be known with certainty until April or May 2007 when the IRS publishes Phase-out Prices for 2006. There can be no assurance that future oil prices will remain under future phase out levels in 2007.

Operations

Effective January 1, 2003, USEB entered into operating and maintenance agreements with RUN Energy for the operation and maintenance of the Countryside and Morris projects. Under the terms of these agreements, RUN Energy is responsible for all expenses related to the operation of the equipment including scheduled major and minor overhauls and the supply of fluids and other spare parts, but excluding repair of failed engine blocks. The existing contracts have one year terms with renewal options.

RUN Energy provides management, operations and maintenance services to the energy industry. RUN Energy is a specialist in distributed power generation, including renewable energy and waste fuels, with a cumulative total of over 6 million hours of operation at over 30 distributed power plants, predominantly in the biogas industry.

On May 1, 2003, the term of the existing operating agreements with GE/Jenbacher for the operation and maintenance of the Brickyard, Dixon Lee, Dolton, 122nd Street, Roxanna, Streator, Upper Rock and Willow Ranch projects were extended to 10 years. Under the terms of these agreements, GE/Jenbacher is responsible for all expenses related to the operation of the equipment including scheduled major and minor overhauls, the supply of fluids and other spare parts and the replacement of failed components. Compensation for the services is at a flat-fixed rate per kWh produced, adjusted based upon the Consumer Price Index and the Producers Price Index. Contract terms include the imposition of penalties or the payment of bonuses should actual production fall below or exceed prescribed levels. The production levels are adjusted periodically to reflect gas quality and quantity.

With the execution of these operation and maintenance contracts, approximately 69% of the engine generating capacity of the Renewable Energy Projects is operated and maintained by third-party operators under fixed price contracts. As the third-party operators are responsible for the relevant projects' day-to-day operations, USEB has been able to reduce its staffing levels and insurance premiums. The variable cost of operation is approximately 74% of total project operating expenses.

The operation and maintenance functions for the remaining Renewable Energy Projects, including Amity, Barre, Brookhaven, Burlington, Cape May, Hamms, Manchester, Oceanside, Onondaga, SPSA I and II, and Tucson are performed by USEB staff, which is comprised of 21 professionals.

THE MANAGEMENT AND ADMINSTRATION AGREEMENTS

Certain provisions of the Management and Administration Agreements are summarized below. Such summaries are qualified in their entirety by the complete text of the Management Agreement and the Administration Agreement which can be found at www.sedar.com

Management Agreement

Under the Management Agreement, the Manager has been engaged to provide or cause to be provided management and administrative services to Countryside Holding and its direct and indirect subsidiaries, and to the extent such services are requested and not provided by Countryside Canada Ventures Inc. (the "Administrator") under the Administration Agreement, Countryside Canada. These management and administrative services include: (i) monitoring and managing the investments of Countryside Holding and, if requested, Countryside Canada and reporting to the directors of Countryside Holding or Countryside Canada (as applicable) with respect thereto; (ii) overseeing the operations management of the assets or entities operated and maintained by Countryside Holding and, if requested, Countryside Canada; (iii) developing, implementing and monitoring strategic plans with a view to maintaining and increasing distributions of the Fund over time; (iv) developing, and monitoring compliance with, the annual budget and the annual Distributable Cash forecast of the Fund and reporting to the applicable board of directors thereon; (v) undertaking or supervising the undertaking of treasury, legal and compliance, financing, risk assessment and human resource activities; (vi) preparing management reports, including financial reports, consistent with past practices, in respect of the assets owned by Countryside Holding and, if requested, Countryside Canada, and any future Projects; (vii) negotiating or overseeing the negotiation of material agreements subject to the approval of the governing bodies of the applicable Countryside entities party to such material agreement; (viii) undertaking or supervising the undertaking of the analysis of potential acquisitions, investments and dispositions, reporting to the applicable board of directors thereon and carrying out or supervising the making of such acquisitions, investments and dispositions, subject to any required approvals; (ix) retaining professional advisers on behalf of Countryside Holding or the applicable subsidiary of Countryside Holding and, if requested, Countryside Canada; (x) advising on and negotiating any financings by Countryside Holding and, if requested, Countryside Canada or its applicable subsidiary subject to the approval of the applicable board of directors; (xi) planning and coordinating board meetings of Countryside Holding and, if applicable, Countryside Canada and its other subsidiaries; and (xii) providing such other management and administrative services as Countryside Holding, its subsidiaries and, if requested, Countryside Canada and its subsidiaries may reasonably request in the conduct of the business and as may be reasonably agreed to from time to time between the parties.

Executives

The Manager is required to provide the services of three qualified individuals with significant experience in the energy and utility infrastructure industry who, in their capacity as officers of the Manager, will provide services that would customarily be provided by senior officers of Countryside Holding, Countryside Canada and its affiliates (together, the "Executives"). The current Executives are Göran Mörnhed, Edward M. Campana and Allen J. Rothman, all of whom are senior executive officers of Countryside U.S. and the current owners of the Manager. For certain additional information about these individuals, see "Trustees, Directors and Management" in this AIF. Appointments by the Manager to provide such services are subject to the approval of the directors of Countryside Holding and Countryside Canada, which approval shall not unreasonably be withheld. If any Executive ceases to be an Executive, the directors of Countryside Holding and Countryside Canada will be provided with prompt notice of this change and will be permitted to participate in the recruitment and identification of a replacement individual. In carrying out their duties on behalf of the Manager under the Management Agreement, the Executives will act honestly and in good faith with a view to the best interests of Countryside Holding and Countryside Canada and will exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

Restrictions on Manager's Powers and Authorities

Pursuant to the Management Agreement, a number of material actions may not be authorized by the Manager without first obtaining the approval of a majority of the directors of Countryside Holding and, if services are being provided to Countryside Canada at the request of Countryside Canada, without first obtaining the approval of a majority of the directors of Countryside Canada. These include: (i) adopting or amending the annual budget of the Fund or taking any action that would be reasonably likely to cause a material deviation from the annual budget; (ii) taking, initiating or consenting to any action that would be reasonably likely to result in a material deviation from the Distributable Cash forecast; (iii) in one or in a series of related transactions, disposing of or consenting to the disposition of any of Countryside Holding's or, if applicable, Countryside Canada's assets with a value in excess of 1% of the gross assets of Countryside Holding, Countryside Canada and their subsidiaries at the time of such disposition; (iv) raising capital or debt by way of an issuance of securities of Countryside Holding or, if applicable, Countryside Canada; or (v) in one or in a series of related transactions, acquiring any material assets or making any material investments by or on behalf of Countryside Holding or, if applicable, Countryside Canada, in each case, with a value in excess of 1% of the gross assets of Countryside Holding or, if applicable, Countryside Canada and its subsidiaries at the time of such acquisition or investment. Without first obtaining the approval of a majority of the directors of Countryside Holding (and, if applicable, Countryside Canada) who are independent of the Manager and its affiliates, the Manager shall not (i) enter into any material transaction with the Manager or an affiliate of the Manager; or (ii) amend any terms of the Management Agreement.

Fees and Payment of Expenses

(i) Base Fee

In consideration for providing the management and administrative services under the Management Agreement, the Manager is entitled to reimbursement from Countryside Holding and, to the extent the Manager provides services to Countryside Canada at its request, Countryside Canada, of all costs and expenses reasonably incurred by the Manager and its affiliates in carrying out the services described above so long as such costs and expenses are incurred in accordance with the annual budget of the Fund and are otherwise permitted or required under the Management Agreement. The Manager shall not be reimbursed under the Management Agreement for the costs and expenses incurred in connection with the origination, structuring or development of energy and utility infrastructure projects except as expressly set out below. Unless otherwise agreed between the parties, the Manager shall be entitled to a minimum aggregate expense reimbursement of US $775,000, representing the annual compensation paid to the Executives (the "Base Salary"), as well as all associated costs, including wage burden and the cost of providing benefits to the executives (collectively the "Base Compensation"). Countryside Holding made an initial reimbursement payment to the Manager upon the execution and delivery of the Management Agreement equal to (i) the amount Countryside Holding would have been obligated to reimburse the Manager for annual base wage compensation and all associated costs if the Management Agreement had been effective for the period from July 1, 2005 to November 1, 2005; less (ii) the amount of payments actually made and to be made by Countryside U.S. Power, Inc. for salaries and all associated costs for the current executive officers for such period. The

Base Compensation will be subject to annual review and periodic adjustment as negotiated and agreed to in good faith by the directors of Countryside Holding, Countryside Canada and the Manager from time to time and subject to independent reviews by third party compensation experts. The Manager shall also be entitled to reimbursement of expenses incurred in good faith in the origination, development and structuring of Development Assets (as defined below), on a cost recovery basis, for investment opportunities in which Countryside Holding, Countryside Canada or their affiliates commit to invest in accordance with the Management Agreement (including the acquisition of Ripon Power). The Manager will not be reimbursed for costs and expenses incurred in connection with the origination, structuring and development of assets or projects that Countryside does not commit to invest in or acquire under the Management Agreement; provided that, if Countryside does commit to invest in or acquire an asset or project and, for whatever reason, such investment or acquisition is not completed, the Manager and Countryside shall share equally in the expenses incurred until the date of commitment.

(ii) Short-Term Incentive Plan

In addition to the Base Compensation and other expense reimbursement, Countryside Holding and, if applicable, Countryside Canada, will also reimburse the Manager for payments made by the Manager to the Executives under a short-term incentive plan ("STIP") to be adopted by the Manager that is consistent with the terms and conditions of the Management Agreement. Countryside Holding, and if applicable, Countryside Canada will reimburse the Manager an amount in respect of the STIP equal to 50% of the Base Compensation ("STIP Pool"), provided that payments will be made based on: (i) meeting certain objectives relating to managing Countryside that are recommended annually by the Manager and subject to the approval of the directors of Countryside Holding and, if applicable, the compensation committee of Countryside Canada in their discretion (the "Operating Objectives"); and (ii) successfully sourcing and consummating an acquisition or investment on behalf of Countryside (the "Acquisition Objective"). In each year, 25% and 75% of the STIP Pool will be available to reimburse the Manager for payments made for achieving the Operating Objectives and the Acquisition Objective, respectively. However, the payment to reimburse the Manager for meeting the Acquisition Objective shall not be less than US$291,000 in each year. The STIP Pool is non-cumulative from year to year. The Manager will be reimbursed by Countryside Holding and/or Countryside Canada: (i) for meeting the Operating Objectives, by payment of both freely tradable Units and cash; and (ii) for meeting the Acquisition Objective (including the acquisition of Ripon) by cash payment only, in accordance with the conditions described in the Management Agreement. Any Units delivered to the Executives under the STIP will be required to be held until the earlier of the termination of the Management Agreement or the termination of the Executive's involvement with the Manager. Respecting 2006, the Manager received US$61,746 cash for meeting the Operating Objectives and US$291,000 cash for meeting the Acquisition Objective in connection with the investment in Countryside London Cogeneration. The Fund waived the requirement that the Executives use the cash payment paid for meeting the Operating Objective to purchase Units because insider trading rules effectively precluded the Executives from the purchasing Units during the strategic review process.

(iii) Long-Term Incentive Plan

The Manager or a designated affiliate will be entitled to receive a long-term incentive plan payment (the "LTIP Interest") in the form of a subordinated interest in each new asset, company or investment (including Ripon Power and Countryside London Cogeneration) acquired or made, directly or indirectly, by Countryside Holding, Countryside Canada or their affiliates and originated, structured or developed through the efforts of the Manager or an Affiliate of the Manager (a "Development Asset"). At the time of approval of any acquisition of, or investment in, a Development Asset by the directors of Countryside Holding or Countryside Canada, as applicable, the Manager will submit to the applicable directors a calculation of the base level distribution (the "Base Level Distribution") that is required to be paid to Countryside Holding or Countryside Canada (as applicable) by the Development Asset to reflect the cost of interest payments on third party debt incurred, and Unitholder distributions on equity raised, to fund the purchase of the Development Asset. The directors of Countryside Holding or Countryside Canada (as applicable) will approve the Base Level Distribution at the time of the approval of the acquisition of a Development Asset or the associated financing, subject to adjustment based on the actual pricing achieved at closing of the acquisition of the Development Asset or the associated financing transaction. The Manager or its applicable affiliate will be entitled to a distribution from the Development Asset of operating cash flow equal to 25% of the cash distributions made by the Development Asset in excess of the Base Level Distribution. Payments to the Manager will be made at the same time as the distribution is made to Countryside Holding or Countryside Canada or their affiliates (as applicable). In the event that a Development Asset owned by Countryside Holding, Countryside Canada or their affiliates (as applicable) makes a distribution of proceeds from capital transactions such as asset sales or recapitalizations, the Manager will be entitled to a 25% share of the capital distribution in excess of an amount required to be paid to Countryside Holding or Countryside Canada or their subsidiary to repay its equity and debt investment in the Development Asset. In the event that, at any time, the Fund reduces its monthly distribution on Units due to a shortfall in Distributable Cash to an amount of less than $0.0854 per unit, up to 25% of the distributions under the aggregate LTIP Interest to be paid during any month in which a shortfall exists shall be subject to reduction to fund the shortfall. For any month that distributions to Unitholders of the Fund are equal to or in excess of $0.0854 per unit, no reductions of the LTIP Interest shall be made. In 2005, the Manager received an LTIP Interest in Ripon Power. In 2006, the Manager received an interest in Countryside London Cogeneration.

(iv) Exchange Options

Countryside Holding or Countryside Canada (if applicable) will have an option ("Exchange Option") to acquire all or part of the Manager's LTIP Interest (also referred to in this AIF as the "Manager's Subordinated Interest") in any Development Asset by paying to the Manager unrestricted and freely tradable Units at any time after 24 months of the date of closing of the acquisition of the Development Asset, at a price equal to the average annualized distributions (including distributed cash and undistributed cash held in the entity owning the Development Asset) which the Manager is entitled to receive under the applicable project agreements described in the Management Agreement from the associated LTIP Interest divided by the yield on Units on the date of exercise of the Exchange Option at the Current Market Price (as defined in the Management Agreement). The Manager will have an Exchange Option to convert all or part of an LTIP Interest in any Development Asset on the basis set out above unless there is a Change of Control (as defined in the Management Agreement) in which case the Manager may exercise the Exchange Option at the Current Market Price within 12 months of such Change of Control. In the event that Countryside decides to engage in a transaction respecting any Development Asset that would constitute a Change of Control as to such Development Asset or the entity owning such Development Asset and in which the Manager retains an LTIP Interest, Countryside Holding or Countryside Canada (as applicable) will have the option of acquiring such interest (notwithstanding that such sale may occur within the first two years of the date of acquisition of the Development Asset) and the Manager will have the option of exchanging such LTIP interest (notwithstanding that such sale may occur within the first two years of the date of acquisition of the Development Asset).

In order to accommodate the Fund's lending syndicate's request that the Manager waive certain rights respecting the Manager's LTIP interest in Ripon Power, on or about January 31, 2007 the parties to the Management Agreement entered into an agreement respecting the Exchange Option respecting the LTIP interest in Ripon Power.

The parties agree that on the earlier of (i) June 29, 2007 and (ii) upon the fifth business day prior to the occurrence of a Change of Control (as defined in the Management Agreement), Countryside Holding will acquire from the Manager, and the Manager will sell to Countryside Holding, 85% of the Manager's LTIP interest in Ripon Power (the "85% Interest") in consideration for 1,444,934 Units, subject to adjustment for certain changes in the Fund's capital structure and a cash payment of \$4,006,528. At Countryside Holding's sole discretion, Countryside may elect in lieu of paying up to 60% of the cash payment to issue up to an additional 288,787 Units to the Manager (such Units to be valued at a price of \$8.32 for the purpose of reducing the amount of the cash payment).

The Manager agreed that from the date of the Amendment, it will have no further right to any distributions in respect of the 85% Interest, provided that there is full performance of the obligations respecting the exchange of the 85% Interest.

The Manager also agreed that from the date of the Amendment, except with respect to distributions on the remaining 15% of the Manager's LTIP Interest in Ripon Power and subject to the full performance of the obligations of Countryside respecting the Purchase of the 85% Interest it will have no rights with respect to any improvement of Ripon. With respect to the remaining 15% of the Manager's LTIP Interest in Ripon Power, the

Manager agrees that, notwithstanding Section 3.03(a) (but subject to Section 3.03(b) and (c)) of the Management Agreement, the neither the Manager nor Countryside will exercise the Exchange Option prior to the earlier of February 9, 2009 or a Change of Control.

The obligations of the Fund respecting the purchase of the 85% Interest may be conditional upon the Fund receiving the prior consent of its lending syndicate pursuant to the Amended Credit Facility. To the extent that such consent is required, the Fund agrees to use its commercially reasonable efforts to obtain such consent if and when requested by the Manager. To the extent that such consent is required and has not been obtained, nothing under the Amendment shall in any way affect the rights and obligations of the parties pursuant to the existing Exchange Option under the Management Agreement, provided that, for clarity, the parties confirmed and agreed that, in the event that distributions of the Fund are suspended, the number of Units shall be calculated as of the date immediately prior to such event.

In the event that the Fund replaces or restructures the existing Amended Credit Facility, Countryside will cause the parties to the new or restructured credit facility (or other loan arrangement) consent and agree to the provisions of the Amendment. Furthermore, upon the occurrence of a Change of Control, the purchase respecting of the 85% Interest shall be completed immediately prior thereto or contemporaneously therewith and to the extent that such Change of Control results in all or substantially all of the outstanding Units being purchased or exchanged for cash and/or other consideration, the Manager shall be entitled to such per unit cash and/or other consideration in lieu of the Units contemplated in the 85% Interest.

Right of First Opportunity

The Manager and its affiliates will provide Countryside Holding or Countryside Canada (as applicable) with the first opportunity to purchase any asset, entity or investment that would meet the investment criteria for Countryside and the Fund (an "Acquisition Opportunity") that it: (i) develops (whether on behalf of Countryside or not); or (ii) owns or controls, provided that no right of first opportunity will be required to be provided for an Acquisition Opportunity if the terms of any agreement governing the Acquisition Opportunity prevent the Manager or its affiliate from providing such right. Countryside Holding or Countryside Canada (as applicable) will have a period of 30 calendar days, from and including the date it receives notice of the Acquisition Opportunity, to advise the Manager or its affiliate that it wishes to pursue the Acquisition Opportunity. If Countryside Holding or Countryside Canada, as applicable, does not provide notice of its intention to pursue the Acquisition Opportunity within 30 calendar days of the date of notice by the Manager, the Manager will be free to offer the Acquisition Opportunity to third parties or pursue it for its own account. Countryside Holding or Countryside Canada, as applicable, has a period of 60 days of such notice to enter into a binding agreement to purchase or invest in the Acquisition Opportunity once it commits to such Acquisition Opportunity provided that Countryside Holding or Countryside Canada will notify the Manager promptly if it decides to cease pursuit of the opportunity prior to the expiration of such 60 day period. If Countryside has not entered into a binding agreement to purchase or invest in the Acquisition Opportunity during such period or provides notice that it no longer wishes to pursue the opportunity, the Manager or its affiliates will be free to offer the Acquisition Opportunity to third parties or pursue it for its own account, subject to certain reimbursement obligations with respect to Countryside Holding or Countryside Canada (as applicable). If the Manager or its affiliate has provided Countryside Holding or Countryside Canada (as applicable) with an opportunity to purchase an Acquisition Opportunity and Countryside Holding or Countryside Canada, as applicable, decided not to invest in such opportunity or did not enter into a binding agreement of purchase and sale within the prescribed time, the Manager shall not be obligated to provide Countryside Holding or Countryside Canada with a further right of first opportunity to invest in such Acquisition Opportunity in the event that the Manager invested in, or otherwise acquired an interest in or proceeded to develop, such Acquisition Opportunity. The Manager is required to keep the directors of Countryside Holding informed of all potential Acquisition Opportunities it is pursuing and is required to provide quarterly updates to the directors of Countryside Holding on such activities.

Term and Termination

The Management Agreement has an initial 20-year term and will be automatically renewed for additional five-year terms unless, at least six months prior to the expiration of the then current term, a majority of the directors of each of Countryside Holding and Countryside Canada who are independent of the Manager determine that the Management Agreement will not be renewed and notify the Manager accordingly. The Manager has the right to immediately terminate the Management Agreement in circumstances of:(i) bankruptcy, insolvency or receivership of Countryside Holding or Countryside Canada; or (ii) a default by Countryside Holding or Countryside Canada in the performance of a material obligation under this Agreement (other than as a result of the occurrence of a *force majeure* event) which is not cured within 60 days of written notice being given by the Manager to Countryside Holding or Countryside Canada of the default (subject to certain exceptions) or if such default is not reasonably capable of being cured within 60 days, Countryside Holding or Countryside Canada, as applicable, has not taken all reasonable steps to cure such default as soon as possible thereafter but in any event within 128 days. Countryside Holding or Countryside Canada have the right to immediately terminate the Management Agreement in circumstances of: (i) bankruptcy, insolvency or receivership of the Manager; (ii) fraud, willful default or gross negligence committed by the Manager; or (iii) default by the Manager in the performance of a material obligation under this Agreement (other than as a result of the occurrence of a *force majeure* event) which is not cured within 60 days of written notice being given by Countryside to the Manager of the default, or if such default is not reasonably capable of being cured within 60 days, the Manager has not taken all reasonable steps to cure such default as soon as possible thereafter but in any event within 128 days.

In addition, the Manager may terminate the Management Agreement (i) at any time after the first five years of the term of the Agreement or (ii) at any time within one year of a

Change of Control, upon 180 days' written notice to Countryside Holding and Countryside Canada. In the event of such a termination, the Manager will be entitled to reimbursement from Countryside Holding and Countryside Canada for actual reasonable costs associated with termination. Countryside Holding and Countryside Canada have the right to jointly terminate the Management Agreement at any time after the first five years of the term of the Management Agreement with the payment to the Manager of a fee equal to (i) its actual costs associated with the termination plus an amount equal to two times the previous year's compensation paid to the Executives by the Manager and reimbursed by Countryside Holding and, if applicable, Countryside Canada, for the Base Compensation and under the STIP for achieving the Operating Objectives or, (ii) if such termination occurs within 12 months of a Change of Control, 2.9 times the previous year's compensation paid to the Executives by the Manager and reimbursed by Countryside Holding and, if applicable, Countryside Canada, for the Base Compensation and under the STIP for achieving certain stated operating objectives. In the event of a Change of Control, Countryside Holding and Countryside Canada will have the right to jointly terminate the Agreement at any time with the payment to the Manager of a fee calculated in accordance with the provisions of the Management Agreement. Termination of the Management Agreement will not affect, among other things, the Exchange Options (subject to certain specified exceptions) or payment obligations of Countryside Holding or, if applicable, Countryside Canada, under the LTIP. On termination of the Management Agreement, any LTIP Interest outstanding at that time shall continue for a period expiring on the date that is 20 years from the date of acquisition of the Development Asset for which the LTIP Interest was issued.

Administration Agreement

Under the Administration Agreement, the Administrator has been engaged to provide or cause to be provided management and administrative services to the Fund and Countryside Canada. The Administrator is responsible for providing the following services to the Fund and Countryside Canada: (i) monitoring and managing the investments and operations of the Fund and Countryside Canada and reporting to the Trustees and the directors of Countryside Canada with respect thereto (provided that it is acknowledged that the Administrator is not responsible for operating the Business); (ii) submitting all annual audited and interim unaudited financial statements of the Fund, income tax returns and filings to the Trustees in sufficient time prior to the dates upon which they must be delivered to Unitholders and/or filed so that the Trustees have a reasonable opportunity to review them, approve them and return them to the Administrator, and arrange for their delivery to Unitholders and/or filing within the time required by applicable law; (iii) ensuring compliance by the Fund with all applicable securities laws; providing investor relations services to the Fund; preparing and providing or causing to be provided to Unitholders on a timely basis all information to which Unitholders are entitled under the declaration of trust of the Fund and under applicable law, including quarterly and annual reports, notices, financial statements and tax information relating to the Fund; (iv) ensuring compliance with the Fund's limitations on foreign ownership; (v) assisting the Trustees in connection with any offerings of Units, including preparing any prospectus or comparable documents of the Fund to qualify the distribution of securities of the Fund from time to time; (vi) assisting Countryside Canada with the analysis of potential acquisitions, investments and dispositions and reporting to the directors of Countryside Canada with respect thereto; (vii) at the direction of the directors of Countryside Canada, assisting with the making of acquisitions, investments and dispositions; (viii) planning and coordinating meetings of the Trustees and the board of directors of Countryside Canada; and (ix) providing such other management and administrative services as the Fund and Countryside Canada may reasonably require as may be agreed to from time to time between the parties.

In carrying out the services described above, the Administrator and its affiliates will be entitled to reimbursement from the Fund and Countryside Canada of all costs and expenses incurred in connection therewith. The Administrator shall discharge the duties conferred upon it hereunder with the same degree of diligence and care that a reasonably prudent manager and administrator of a business substantially similar to the Business, and having responsibilities of a similar nature to those hereunder, would exercise in comparable circumstances.

The Administration Agreement shall remain in effect for so long as the Management Agreement remains in effect. The Administration Agreement may be terminated by either the Administrator or the Fund and Countryside Canada if the other party commits an event of default described under "— Management Agreement" above. In addition, the Administrator may terminate the Administration Agreement upon 180 days' written notice to the Fund and Countryside Canada. The Fund and Countryside Canada have the right to jointly terminate the Administration Agreement at any time after the first five years.

Development Agreement with Cinergy and USEY

The Fund, through its wholly-owned indirect subsidiary, Countryside U.S. Power, entered into a Development Agreement with an indirect subsidiary of Cinergy (now and indirect subsidiary of Duke Energy) and USEY under which, subject to its terms and conditions, the Cinergy subsidiary and USEY contribute their experience and financial resources to the acquisition, development, improvement and operation of energy projects that they choose to pursue and that will meet the Fund's investment and growth objectives.

In consideration for development services to be performed under the Development Agreement, Countryside U.S. Power was to receive an annual fee of US$430,000 from an indirect subsidiary of Duke Energy and USEY. USEY ceased making monthly payments under the Development Agreement in May 2005. After unsuccessful efforts to negotiate a resolution, in July 2006, Countryside U.S. Power commenced an action against USEY in New York State Supreme Court, New York County styled Countryside U.S. Power Inc. v. U.S. Energy Systems, Inc. for breach of contract seeking all amounts due from USEY over the remaining of the Development Agreement. USEY filed an answer denying the allegations in the complaint and alleging counterclaims seeking, among other things, to void the Development Agreement. In December 2006, Countryside U.S. removed the state court litigation to the United States District Court for the Southern District of New York which thereafter transferred the case to the United States Bankruptcy Court for the Southern District of New York where it became a related adversary proceeding in the USEB Bankruptcy styled Countryside U.S. Power, Inc. v. U.S. Energy Systems, Inc. Adv. No. 06-15350 (RDD). As part of the USEB Settlement which became effective on March 7, 2006 Countryside U.S. Power and USEY released all claims they had against each other relating to the Development Agreement and obtained an order dismissing the Development Agreement litigation with prejudice. Accordingly neither party has any rights or obligations respecting each other under the Development Agreement.

DISTRIBUTIONS

Distribution Policy

Monthly distributions are made to Unitholders of record on the last business day of each month and are expected to be paid to Unitholders on or about the 30th day of the following month.

History of Distributions

The following table sets forth the per Trust Unit amount of monthly cash distributions paid or declared but not yet paid by the Fund from January 1, 2005 through and including December 31, 2006.

Distributions Per Trust Unit	2005	2006
January	$0.0855[1]	$0.0863
February	$0.0854	$0.0863
March	$0.0854	$0.0863
April	$0.0854	$0.0863
May	$0.0854	$0.0863
June	$0.0854	$0.0860[1]
July	$0.0855[1]	$0.0863
August	$0.0854	$0.0863
September	$0.0854	$0.0863
October	$0.0863[2]	$0.0863
November	$0.0863	$0.0863
December	$0.0863	$0.0860[1]

(1) These amounts make up for rounding differences in prior months.
(2) Distributions per unit were increased by $0.01 per annum or $0.0009 per month commencing with the October 2005 distribution.

Distribution Restrictions

Under the terms of the Fund's Amended Credit Facility, distributions, intercompany debt payments and other distributions cannot be made by the borrower or the guarantors thereunder in the event of a default under the Fund's Amended Credit Facility. In such case Countryside Canada would not be able to provide the Fund with cash necessary to pay distributions or make interest payments under the Debentures. See "Risk Factors – Risks Related to the Structure of the Fund - Financial Leverage and Restrictive Covenants". Under the terms of the Debentures, in the event of a default, the principal payments under the Debentures may be accelerated. In such event, it is unlikely that Countryside Canada would be able to pay dividends, intercompany debt payments and other distributions to the Fund until the Debentureholders were repaid.

MARKET FOR SECURITIES

The outstanding Units of the Fund are listed for trading on the Toronto Stock Exchange under the symbol COU.UN.

Trading Price and Volume

The following table sets forth the reported high and low closing prices and average daily trading volumes of the outstanding Trust Units as reported by the Toronto Stock Exchange for each month commencing and including January 2006 through and including December 2006.

Period 2006	Monthly Average of Daily High Price	Monthly Average of Daily Low Price	Monthly Average of Daily Trading Volumes
January	$ 9.29	$ 9.10	85,140
February	$ 9.75	$ 9.56	51,314
March	$ 9.96	$ 9.83	99,523
April	$ 10.0	$ 9.86	36,244
May	$ 9.87	$ 9.70	36,376
June	$ 9.66	$ 9.46	24,787
July	$ 9.69	$ 9.50	32,004
August	$ 9.84	$ 9.75	47,790
September	$ 9.96	$ 9.88	55,285
October	$ 10.15	$ 10.04	76,530
November	$ 8.48	$ 8.00	175,241
December	$ 6.66	$ 6.36	271,681

Source: Information derived from TSX market data via third party stock quote link: Stockhouse.

RISK FACTORS

The following are certain risk factors relating to the Fund. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this annual information form and in the Fund's filings with the Canadian Securities Regulators from time to time including the Fund's final long form prospectus dated March 29, 2004, its short form prospectus dated November 8, 2005 and its Annual Information Form For The Year Ended December 31, 2005, Dated March 31, 2006 (the "2005 AIF"), which can be found at www.sedar.com. Risks relating to the Renewable Energy Projects are applicable to the Fund to the extent they affect: (i) USEB's ability to meet it's obligations under the Allowed Secured Claim; and (ii) Countryside Canada's ability to realize value in the event it sells or enforces its rights under the Allowed Secured Claim. In the event USEB satisfies the Allowed Secured Claim in accordance with its terms, risks relating to the Renewable Energy Projects are unlikely to have a material adverse effect on the Fund.

Risks Related to the Business

Dependence Upon Key Customers

Electricity generated from the Ripon and San Gabriel Facilities has historically been purchased by PG&E and SCE, two local electric utilities, under long-term PPAs. Steam generated from the Ripon and San Gabriel Facilities has historically been sold to two nearby paper mills. If for any reason such customers are unable or unwilling to fulfill their contractual obligations under the relevant PPAs and Steam Agreements or such agreements are otherwise terminated, the financial condition of Ripon Cogeneration could decline and reduce Ripon Cogeneration's ability to generate distributable cash. Additionally, if the paper mills fail to meet their contractual obligations, the Ripon and San Gabriel Facilities' status as QF's could be endangered with the consequences described below (the "Qualifying Facility Status").

San Gabriel Facility's QF status, up to a limit in excess of US$4,000,000. See "Risk Factors – Risks Related to the Business - Qualifying Facility Status at Ripon Cogeneration and USEB".

Electricity generated from the Renewable Energy Projects has historically been purchased by local electric utilities under long-term PPAs. Although USEB attempts to ensure that such customers have acceptable credit ratings upon entering into these contractual agreements, if for any reason such customers are unable or unwilling to fulfill their contractual obligations under the relevant PPAs, the financial condition of USEB could decline and reduce USEB's ability to service the USEB Loans.

The District Energy Systems are reliant on a limited number of customers. Furthermore, a significant number of these customers purchase energy at will and can stop purchasing energy at any time. While the majority of these customers have financial support from either the provincial and/or the federal government in Canada, or are entities with a high quality credit rating, the loss of one or more of these customers could adversely impact the financial condition of Countryside District Energy.

Steam Host Termination for Convenience at Ripon

Both Fox River and Blue Heron are permitted to terminate their respective steam sales agreements for convenience under certain circumstances. Each steam sales agreement provides that, in such event, the steam customer must make a specified monetary payment to Ripon to cover Ripon's cost of obtaining a replacement steam host. Blue Heron's obligation to make such payment terminates after the expiration of the initial 12 years of the agreement. Blue Heron may also discharge its obligation by obtaining a replacement steam host. If, Blue Heron ceases operations at its San Gabriel Paper Mill it may exercise its termination right. It is possible that either steam host may exercise such termination right but fail to comply with its obligations to obtain or fund the cost to obtain a replacement steam host due to lack of resources or for other reasons. In such event Ripon may not have an adequate remedy against the steam host and be required to obtain a replacement steam host at its own expense or risk losing its QF status. Loss of QF Status would have a material adverse effect on Ripon. See ''Risk Factors — Qualifying Facility Status''.

On March 7, 2007, Blue Heron Paper Company ("Blue Heron") announced that it had issued a plant closing warning to its employees at the paper mill which serves as the Steam Host for the San Gabriel Facility. In the announcement, Blue Heron claimed that the potential closing was due to shrinking margins caused by recently increasing waste paper costs and decreasing newsprint prices. At this juncture, it is uncertain whether the mill will close. A mill closing may have a material adverse effect on the San Gabriel Facility's QF Status unless alternative steam sales arrangements are made. The Manager is currently exploring various measures to mitigate against any such adverse effect including alternative arrangements with Blue Heron that would protect the San Gabriel Facility's QF even if the paper mill ceases or suspends its current operations and/or applying for a temporary exemption (i.e. one or two years) from QF thermal output requirements from the FERC while more long term mitigation measures are implemented. Under the steam sales agreement, Blue Heron is required to purchase a minimum volume of steam annually from the San Gabriel Facility and is liable for costs associated with replacing Blue Heron as a steam customer to preserve the San Gabriel Facility's QF status, up to a limit in excess of $4,000,000. Subject to preservation of QF status, the adverse effect of a mill closing on the Fund would not be expected to be material. See "Risk Factors – Risks Related to the Business - Qualifying Facility Status at Ripon Cogeneration and USEB".

Competition

In markets in which Ripon and USEB operate and in which Countryside London Cogeneration will operate, there is competition from companies who are involved in power generation. Some of these companies have access to greater financial resources and have a greater ability to attract and retain personnel than Ripon, Countryside London Cogeneration or USEB. Although the Manager believes that there are segments of the marketplace where USEB will not face extensive competition, no assurances can be made that USEB will be able to enter these markets or that there will not be competition in such markets. Additionally, in recent years, such competition has contributed to a reduction in electricity prices in certain markets.

The principal competition for the District Energy Systems is from a wide variety of firms that sell products or services to end-users who choose to build and operate heating and cooling equipment on their own premises. These firms include suppliers of boilers and chillers and fuel suppliers such as gas and electric utilities, which encourage use of equipment, that use their products. Some of these suppliers have greater financial resources than the District Energy Systems. In addition, increased competition could result in lower prices for the District Energy Systems' products and services.

Seasonality at California Cogen Facilities and the District Energy Systems

The Ripon and San Gabriel Facilities are expected to generate the majority of their gross revenues in the period from May to August because the PPAs provide higher levels of payments during this period. The District Energy Systems are expected to generate the majority of their gross revenues in the period from November to March because they derive the majority of their revenues from the sale of heat and demand for heat is highest during this period. To the extent that equipment at either the Ripon Facility, the San Gabriel Facility or the District Energy Systems require maintenance and repair, or suffer disruptions of operation for other reasons during their respective peak revenue periods, their ability to generate distributable cash may be negatively impacted.

Electricity Pricing at Ripon, Countryside London Cogeneration and USEB

On or about July 14, 2001, Ripon Cogeneration and PG&E entered into a 5 year amendment of the Ripon PPA which substituted PG&E's SRAC with a primarily fixed energy rate (subject to adjustment for time of use factors). When this amendment expired in July 2006, Ripon Cogeneration again received energy payments under the Ripon PPA based on PG&E's SRAC prices. The San Gabriel Facility currently receives a monthly energy payment for energy delivered to SCE in an amount calculated by reference to SCE's SRAC pursuant to an agreement which terminated on July 1, 2006, at which time Ripon Cogeneration commenced receiving energy payments under the San Gabriel PPA based on SCE's SRAC prices. Currently, the SRAC energy prices are based on the Transition Formula, which is determined separately with respect to each utility on a monthly basis. The authority to modify the elements of the SRAC energy price formula rests with the CPUC, subject to certain statutory requirements imposed by the *Electric Utility Industry Restructuring Act* (Assembly Bill 1890). There is an open proceeding in which the CPUC has indicated it will review the Transition Formula for SRAC pricing for possible prospective changes. There can be no assurance that any change in the SRAC price methodology will not adversely affect the operating margins derived from the Ripon PPA and San Gabriel PPA. Any adverse change in energy margins may negatively impact Ripon Cogeneration's cash flow which in turn could reduce distributable cash.

Ripon Cogeneration's PPAs at the Ripon Facility and the San Gabriel Facility terminate in 2018 and 2016 respectively. There can be no assurance that, upon the expiry of such PPAs, Ripon Cogeneration will be able to enter into new PPAs or otherwise sell its power into the market at prices at or above projected levels. Future prices and rates cannot be predicted with certainty and will inevitably deviate from such forecasts and such deviation may be material. Significant declines in prices and rates would be expected to have a material adverse impact on Ripon Cogeneration upon expiry of the PPAs.

Once the London Cogen Facility has commenced commercial operation, Countryside London Cogeneration expects to sell power into the IESO administered wholesale market at HOEP prices which cannot be predicted with certainty and which will inevitably deviate from forecasts, perhaps materially. Significant declines in HOEP prices may have some impact on Countryside London Cogeneration although such affect should be mitigated by the Contingent Support Payments received under the CHP Contract with the OPA.

While a majority of the off-takers of the Renewable Energy Projects are contractually obligated to purchase electricity under long-term PPAs, the projects based on market pricing will be exposed to fluctuations in the wholesale price of electricity. In addition, should any of the long-term contracts terminate or expire, USEB will be required to either negotiate new PPAs or sell into the electricity wholesale market for electricity, in which case the prices for electricity will depend on market conditions at the time. Similarly, if the Renewable Energy Projects located in Illinois cease their participation in the Rate Incentive Program on May 31, 2007 under the proposed settlement with the State of Illinois or are otherwise no longer eligible to receive incentives under the Rate Incentive Program, it is expected that the projects will seek to negotiate new contracts in the Green Power Market based on rates prevailing in the Green Power Market at the time.

For a description of the electricity pricing risks to USEB's Illinois-based Renewable Energy Projects if the proposed settlement between USEB and the state of Illinois is not consummated and such projects remain participants in the Rate Incentive Program see the 2005 AIF, "Risk Factors-Electricity Pricing at Ripon and USEB

Capacity Payments at Ripon and Countryside London Cogeneration

The Ripon and San Gabriel Facilities are dependent on capacity payments due from PG&E and SCE, respectively, as the case may be. Under the PPAs, each Facility's ongoing ability to receive the full firm capacity payment is conditioned upon the delivery of the contract capacity during on-peak hours during the summer peak months (June through August for PG&E and June through September for SCE), although both facilities receive the benefit of a twenty percent monthly forced outage allowance during the summer peak months. If either Facility fails to meet the performance criteria, the purchasing utility has the right to declare a probationary period of up to fifteen months after which, if the performance criteria is not met, the Facility may be de-rated, the capacity payment reduced and the Facility subjected to a refund obligation based on the difference between original capacity and reduced capacity plus interest thereon. Finally, the capacity payment may be reduced by PG&E and suspended by SCE if the Ripon Facility or the San Gabriel Facility, respectively, is unable to meet its performance obligations as a result of a force majeure-type event that continues for longer than ninety days.

Under the CHP Contract, if the London Cogen Facility fails to deliver the Contract Capacity, the Fixed Capacity Payment (which is a component of the Contingent Support Payment calculation) will be reduced proportionately. Further if the London Cogen Facility fails to deliver 80% of Contract Capacity after a Further Capacity Check Test (as defined in the CHP Contract), Countryside London Cogeneration will be in default under the CHP Contract. If the London Cogen Facility operates between 80 and 100% of Contract Capacity, the OPA may require that a series of Capacity Check Tests (as defined in the CHP Contract) be conducted. If the London Cogen Facility fails to operate at 100%

of Contract Capacity in at least one of such Capacity Check Tests it shall be in default under the CHP Contract. Upon a default, the OPA may terminate the CHP Contract and seek monetary damages.

Any adverse change in capacity and/or capacity bonus payments or Fixed Capacity Payments may negatively impact Ripon's or Countryside London Cogeneration's cash flow (as applicable) which in turn may negatively impact Countryside Canada's cash available to pay interest on the Debentures and the Fund's distributable cash. Termination of the CHP Contract could have a material adverse impact on the Fund

Natural Gas Fuel Availability and Price at Ripon and Countryside London Cogeneration

The Ripon and San Gabriel Facilities use natural gas for fuel. The Ripon Facility currently purchases natural gas under index-based contracts that expire in 2008. There can be no assurance that Ripon will enter into new long-term gas contracts or otherwise purchase natural gas in the market on the same basis as the current contracts. Ripon has also entered into gas transportation contracts under which the natural gas is transported from the gas supplier's delivery point to the Ripon and San Gabriel Facilities. The pricing under such contracts is governed by tariffs filed with the CPUC. The contracts currently expire in 2007. Upon expiry there can be no assurance that Ripon will be able to renew the gas transportation contracts at the same rates as it receives today, and therefore Ripon's fuel transportation costs may decrease or increase the distributable cash generated by Ripon.

Once in commercial operation, the London Cogen Facility will use natural gas fuel purchased at cost from Countryside District Energy. Countryside District Energy is currently seeking to finalize an index based gas purchase agreement with its current gas supplier for the incremental gas to be used by the London Cogen Facility and a gas transportation agreement with its existing gas transmission company. There is no assurance Countryside District Energy will successfully complete such negotiations on terms consistent with the terms anticipated when Countryside London Cogeneration entered into the CHP Contract. Failure to enter into such agreements on such terms may have a material adverse effect on the successful development of and/or distributable cash generated by the London Cogen Facility.

Lack of Correlation Between Energy Prices and Fuel Costs at Ripon and Countryside London Cogeneration

The energy prices charged by each of the Ripon and San Gabriel Facilities are currently based on the SRAC of the applicable utility. The CPUC is currently considering the future methodology for computing SRAC for each utility in an open proceeding. Although the outcome of such proceeding is uncertain, the Manager believes that the CPUC will likely implement an SRAC methodology that indexes energy prices, in part, to an index of natural gas prices. However it is unknown what specific gas index the CPUC will choose for each utility and how energy prices will correlate to such index.

Ripon has entered into new gas contracts that will correlate gas prices with location based indices. It is uncertain whether such local-based indices will correlate with gas indices to be employed in the future applicable SRAC formulas and in that way ensure that energy prices received by Ripon adjust with movements in gas prices. In the event that gas indices in future SRAC formulas do not correlate with the location based indices in existing or future gas contents and gas prices increase without compensating adjustments in energy prices received by Ripon, operating margins at the Ripon and San Gabriel Facilities may be reduced, in turn reducing Ripon's distributable cash.

Under the CHP Contract, London Cogeneration System's Contingent Support Payments are in part dependent on Dawn Index gas pricing. In the event Countryside District Energy does not enter into a gas purchase contract for the gas to be used by the London Cogen Facility based on Dawn Index pricing and the pricing under such gas purchase contract is higher than the applicable Dawn Index, Countryside London Cogeneration's operating margins may be reduced, in turn reducing Countryside London Cogeneration's distributable cash.

Resource Availability and Constancy at USEB and the District Energy Systems

The Renewable Energy Projects rely on the extraction of biogas from public and privately-owned landfill sites. The quantity of available biogas is determined by numerous factors beyond the control of USEB including, without limitation, filling pattern of the landfill, the composition of the waste, compaction, moisture content, time and climatic conditions. In the event that the amount of biogas produced by a landfill and/or its methane component is less than expected, or the duration of biogas emission is shorter than expected, the sale of biogas by USEB, the production of electricity by USEB and/or the amount of revenue received by USEB from the sale of Gascos producing Section 29 tax credits may be adversely affected in a material manner.

Generally with respect to each Renewable Energy Project: (i) the Gasco's right to extract biogas from the landfill is subject to a long-term gas rights agreement with the landfill owner; (ii) the Genco or Transco's right to purchase biogas from the Gasco is subject to a long-term gas purchase agreement with the Gasco; and (iii) the Genco or Transco's right to occupy the landfill is subject to a long-term lease with the landfill owner. If one of the foregoing agreements or leases was terminated prematurely, for any reason the relevant Renewable Energy Project would be affected in a material adverse manner.

Project Development and Expansion Risks

The ability to develop new projects and expand existing projects including any repowering or expansion of the California Cogen Facilities requires success in obtaining various agreements, permits and approvals that are, in certain cases, not within the control of the Manager including power purchase agreements, steam sale agreements and easements. No assurances can be given that the Manager will be successful in obtaining these agreements, permits, equipment and approvals on satisfactory commercial terms.

Project development and expansion also involves significant environmental, engineering and construction risks.

London Cogeneration Project

Under the CHP Contract Countryside London Cogeneration is required to commence commercial operation (as defined in the CHP Contract) by June 1, 2008 (the "Commercial Operation Date"), failing which the Countryside London Cogeneration is subject to liquidated damages in accordance with a formula set forth in the OPA Contract. The Commercial Operation Date may be adjusted for force majeure. The maximum exposure to Countryside London Cogeneration under this provision would be approximately $1 million dollars.

In addition, if the commercial operation date does not occur within one (1) year after such date, then such failure would permit the OPA to terminate the CHP Contract unless Countryside London Cogeneration has paid all liquidated damages accruing to the one year date and provided the full amount of the required completion and performance security. The failure to reach the commercial operation date within eighteen (18) months after the commercial operation milestone would be considered an event of default giving rise to the right of Countryside London Cogeneration to terminate the CHP Contract and sue for damages.

Countryside London Cogeneration has provided completion and performance security to the OPA of $602 upon which the OPA may draw to satisfy any damage claims. Countryside London Cogeneration is obligated to replenish any amounts drawn upon.

The profitability of the CHP Contract for Countryside London Cogeneration will be reduced to the extent Countryside London Cogeneration operates at less than the capacity or efficiency contained in its bid or with higher O&M costs contained in its bid.

There are events of default for Countryside London Cogeneration. These additional events of default include: a cross-default provision (default by Supplier of financial obligations to a third party); failure to meet the commercial operation date; failure to meet the availability requirements; capacity check requirement failures; and performance security failures subject to cure provisions.

For certain Countryside London Cogeneration events of default, the OPA is entitled to levy a performance assessment set-off, as liquidated damages equal to three (3) times the average Contingent Support Payment (as defined in the OPA Contract) payable to Countryside London Cogeneration for the most recent twelve (12) months where there has been three (3) or more Countryside London Cogeneration events of default within a contract year regardless of whether such events had been subsequently cured.

The development of the London Cogen Facility is subject to risks normally associated with development projects of this type including construction and equipment procurement delays, cost-overruns, permitting, labour disruptions, fuel procurement, interconnection issues etc. However Countryside London Cogeneration has sought to mitigate the risks by entering into a fixed price engineering, procurement and construction contract with Meccon London Inc. backed by performance and payment bonds. In addition, material land use and air and noise emissions permits have been obtained. Nonetheless there are no assurances that the London Cogen Facility will be completed on time or on budget and without any additional exposure to Countryside London Cogeneration.

Insurance

There can be no assurance that insurance obtained in respect of the Fund's operations and USEB's operations, including business interruption insurance among others, will be sufficient, continue to be offered on commercially reasonable terms or that events that could give rise to a loss or liability are insured. A significant event which is not fully insured could have a material adverse effect.

Operating Risks

The operation of energy generation facilities involves many risks, including the breakdown or failure of equipment or processes, and performance below expected levels of output or efficiency. If operations are interrupted at these facilities due to mechanical failures or for other reasons, it could have a negative effect on distributable cash.

Reliance on Third Party Operator at Ripon and USEB

Ripon has entered into operation and maintenance agreements with NAES for the Ripon and San Gabriel Facilities. USEB has entered into operation and maintenance agreements with GE/Jenbacher and RUN Energy for eight and two of its projects respectively. As a result, Ripon and USEB are and will be dependent on these third party operators for the successful operation of these projects. To the extent these third party operators do not fulfill their obligations under their respective agreements, the operations at these projects could be adversely affected.

Force Majeure Events

It is possible that force majeure events may disrupt operations or development at or cause substantial damage to the Ripon Facilities, the District Energy Systems, the Renewable Energy Projects and the London Cogen Facility. As the Ripon Facilities are located in California, such force majeure events may include earthquakes. While the Fund and USEB have obtained insurance, including earthquake insurance in the case of Ripon, to mitigate any financial costs arising from such force majeure events, there is no assurance such insurance will fully cover such risks and costs or will continue to be available to the Fund and USEB on terms which are commercially reasonable.

Regulatory Approvals

The construction and operation of energy projects requires numerous permits from governmental agencies, as well as compliance with environmental laws and other regulations. While the Manager believes that the projects are in substantial compliance with all applicable regulations and that each of the projects has the requisite permits, regulators and reviewing courts may conclude otherwise. There can be no assurance that new laws, regulations or orders or amendments to or new, more stringent interpretations or enforcement policies with respect to existing laws, regulations or orders which would have a material adverse effect on the Fund's projects or the Renewable Energy Projects will not be adopted or that completed projects will comply with all applicable permit conditions, statutes and regulations. If any of the Fund's projects or the Renewable Energy Projects fails to obtain or maintain any required permit or fails to comply with any applicable law, regulators may take enforcement actions which could have a material adverse effect on the applicable project.

Environmental Health and Safety Risks

The Ripon Facilities, the Renewable Energy Projects, the District Energy Systems and the London Cogen Facility are regulated by numerous and significant laws, regulations, by-laws, guidelines, policies, directives and other requirements relating to environmental and safety matters. The Ripon Facilities, Renewable Energy Projects, District Energy Systems and the London Cogen Facility have obtained environmental permits that are required for their operation. Although the Manager believes that the operations of the facilities are currently in material compliance with applicable environmental laws and permit requirements (subject to the Ripon Facility variance described below) , there is no guarantee that more stringent laws will not be imposed, that there will not be more stringent enforcement of applicable laws, that regulators and courts may disagree with the Fund's interpretation of such laws in which case such regulators and courts' interpretation may prevail or that such systems may not fail, which may result in material expenditures. Failure by the projects and systems to comply with any environmental, health or safety requirements, or increases in the cost of such compliance, including as a result of unanticipated liabilities (whether as a result of newly discovered issues or known issues that have not been quantified) or expenditures for investigation, assessment, remediation or monitoring, could result in additional expense, capital expenditures, restrictions and delays in the projects' and systems' activities, the extent of which cannot be predicted and which may be material.

In May 2006, the Ripon Facility performed a diagnostic test which revealed that its auxiliary boiler could not be operated in compliance with its operating permits at all load conditions. Since that date the Ripon Facility has received variances from the San Joaquin Valley Unified Air Pollution Control District (the "San Joaquin District") which, among other things, permit the Ripon Facility to operate the auxiliary boiler with excess NOx and CO emissions subject to certain conditions. The current variance expires on the earlier of October 31, 2007 or when the subject boiler achieves compliance with the permitted emissions limit whichever comes first. Ripon Cogeneration is currently exploring different methods of achieving compliance including equipment modifications and permit modifications. The auxiliary boiler is used to provide steam to Fox River, in conformance with the requirements of the steam agreement, when the Ripon Facility gas turbine is not operating. If the auxiliary boiler cannot run, Ripon Cogeneration plans to operate the gas turbine.

From time to time, Ripon Cogeneration has received notices of violation ("NOV's") from the San Joaquin District respecting alleged violations of applicable laws and permits. Such NOV's do not allege excess emissions (except one NOV involving an immaterial amount of excess emissions for a short duration) but mainly relate to data collection and reporting. Ripon Cogeneration has settled certain of the NOV's for immaterial sums and intends to contest or resolve the pending NOV's on terms which are not expected to be materially adverse to the Fund. Ripon Cogeneration is in the process of upgrading its data collection equipment. The Manager believes such upgrade will address the compliance issues raised by the NOV's on a long-term basis.

Qualifying Facility Status at Ripon Cogeneration and USEB

The Ripon Facility, the San Gabriel Facility and a majority of USEB's Renewable Energy Projects have been certified by the FERC as QFs and operate in compliance with the applicable criteria under PURPA. Loss of QF status could trigger defaults under covenants to maintain QF status under the PPAs and, in the case of USEB, the USEB Loan and could result in the potential termination of the PPA and penalties and/or, in the case of USEB, acceleration of indebtedness thereunder plus interest. Further, the purchasing utility may have the right under the PPA to refuse to purchase electricity from the QF at such utility's Avoided Cost if QF status were lost and might be entitled to certain remedies for breach of an existing PPA including the right to terminate the PPA. In addition, the FERC has asserted jurisdiction over the rates charged by QFs during periods when a facility does not operate in compliance with the applicable QF criteria and has indicated its willingness to order the refund of payments previously made under PPAs in some cases. Further, loss of QF status could result in the loss of the exemption under PURPA from utility-type regulation and expose either Facility to regulation by FERC under the Federal Power Act and by the CPUC under the California Public Utilities Code. In the event Blue Heron ceased or suspended operation of its San Gabriel paper mill, the San Gabriel Facility's QF status may be put at risk. (See "Risk Factors-Risks Related To The Business-Steam Host Termination For Convenience at Ripon")

Any of these consequences would result in substantial regulatory burdens, potentially lower revenues from power sales and potentially insurmountable impediments to affected entities with regard to conducting business in the manner currently contemplated. Accordingly, the ability of the Ripon and San Gabriel Facilities to generate distributable cash and the ability of the Renewable Energy Projects to generate cash for USEB to make debt service payments on the USEB Loan is dependent on their maintaining QF status. A facility may lose its QF status either temporarily or permanently.

Congress from time to time has considered legislation to repeal and amend certain provisions of PURPA, most recently with the enactment of EPA 2005. Such legislation has typically included "grand-fathering" protection to ensure that any change in law would apply only prospectively and would not affect the obligation of electric utilities to purchase from QFs under their existing PPAs. However, there is no guarantee that any future legislation would contain "grand-fathering" protection.

Loss of QF status by any Illinois-based Renewable Energy Project would cause it also to lose its QSWEF status.

QSWEF Status of USEB's Illinois-based Biogas Projects

Eligibility for the Rate Incentive Program is based on compliance with the requirements contained in Illinois Public Utilities Act, the ICC Regulations and the ICC Orders issued by the ICC respecting QSWEF's. A QSWEF would lose all or some of the benefits provided by the Rate Incentive Program if it were found to be in non-compliance with these requirements. Similarly, a QSWEF may lose all or some of such benefits in the event of modifications to the *Illinois Public Utilities Act*, the ICC Regulations, the ICC Orders or ICC policies or repeal of the *Illinois Public Utilities Act.* In such event, the revenues and profits from the affected QSWEFS may be materially adversely impacted. From time to time, legislation modifying the Illinois Public Utilities Act has been proposed. If certain of the introduced legislation had been enacted in its proposed form, it would reasonably be expected to have a material adverse effect on the QSWEFS. To date such legislation has not been enacted; however there can be no assurance that such legislation will not be enacted in the future.

The State of Illinois has moved the Bankruptcy Court in the USEB Bankruptcy for relief from the automatic stay in order to commence administrative proceedings to determine whether USEB's Illinois-based Renewable Energy Projects should lose their QSWEF status. While such motion was pending, on March 22 , 2007 USEB disclosed that it had reached a settlement with the State of Illinois under which, among other things, USEB would allow the State of Illinois an unsecured claim of US$ 5.3 million in the USEB Bankruptcy in full satisfaction of any reimbursement claim and all of USEB's Illinois-based Renewable Energy Projects would withdraw from the Rate Incentive Program effective May 31, 2007. Such settlement is subject to the approval of the Bankruptcy Court in the USEB Bankruptcy.

The ability of USEB to meet its repayment obligations under the Allowed Secured Claim may be affected by the loss of Illinois-based Renewable Energy Projects' QSWEF status. If USEB pays the Fund the balance of the Allowed Secured Plan, loss of QSWEF status is unlikely to have a material adverse effect on the Fund.

Section 29 Tax Credits at USEB

USEB currently receives income from the sale of Code Section 29 tax credits which will expire on December 31, 2007 unless the law is extended. Part of the purchase price is contingent on gas production. If gas production were to fall, USEB's revenues may decline. USEB has agreed to indemnify the financial investors that have purchased interests in the Gascos for certain losses suffered by such investors in the event that the Section 29 tax credits are denied in certain circumstances.

In addition, through December 31, 2007, Code Section 29 has a phase out provision that is triggered when the "Market Wellhead Price" of domestic crude oil reaches certain "Phase-out Prices" as determined by the IRS. The phase-out is proportional. The Market Wellhead Price is the IRS' estimate of the calendar year average wellhead price per barrel for all domestic crude oil, the price of which is not subject to regulation. Phase out Prices are adjusted each year for inflation. The IRS will not publish the Phase-out Prices and Market Wellhead prices for calendar year 2006 until April or May 2007. Historically, the Market Wellhead Prices oil prices have been substantially below "Phase-out Prices" and therefore the possibility of a phase-out has been considered remote. However, due to higher oil prices, estimated Market Wellhead Prices in 2006 have generally, exceeded the price at which the estimated Phase out is expected to be triggered. Accordingly it is estimated there will be some Phase-out of the Section 29 tax credit in 2006 although whether in fact a Phase out will be triggered for 2006 and the extent of such Phase out will not be determined until the IRS publishes Phase-out Prices and Market Wellhead Prices for 2006. Further there can be no assurance that future oil prices will be under future Phase out levels in 2007. If a Phase out is triggered during 2006 or 2007, USEB's income from Code Section 29 tax credits may be reduced or eliminated, thus reducing USEB's income and cash flow.

The universe of projects eligible for tax credits is limited based on restrictions contained in Section 29. From time to time, legislation has been proposed to renew Section 29 tax credits, but it is uncertain whether this legislation will be enacted, what its final form will be, and in particular whether such legislation would extend Section 29 tax credits for existing projects or make them available only for new projects. The unavailability of these tax credits for future renewable energy projects may make such future projects less attractive for investment. The expiration of these tax credits for existing projects may make some renewable energy projects financially unviable and reduce USEB's revenues.

Neither USEB, any of the Gascos, nor any Gasco partner has received a ruling from the IRS confirming that the biogas facilities of the Gascos meet the requirements of Section 29, that the sales of interests in the Gascos by USEB were structured in a way that would entitle the buyers to Section 29 credits, or that sales of methane from the Gascos to the Gencos or Transcos generate Section 29 credits. While a ruling is not required, as is the case with any Section 29 transaction in which a ruling is not obtained, the IRS may challenge the availability of Section 29 credits to any of the Gascos or to its partners.

Potential Refund Liability at Ripon

A proceeding is currently pending before the CPUC in Docket No. R 99-11-022 in which the CPUC is considering whether to apply retroactively for the period December, 2000 through March, 2001 a March, 2001 decision (D. 01-03-067) which, among other things, modified the methodology used in calculating SRAC and thereby decreased SRAC levels for the period commencing March 27, 2001. SCE and several other parties sought judicial review of D. 01-03-067 and two related CPUC decisions. In September, 2002, the California Court of Appeals found that the CPUC had violated PURPA for failing to consider SCE's argument that the CPUC should retroactively apply the modified SRAC formula. *Southern Cal. Edison vs. Public Utilities Comm'n.*, 101 Cal. App. 4th 982 (2002). The Court of Appeals directed the CPUC to consider SCE's request. In 2003 and 2004, comments on the issue were submitted to the CPUC by various parties and the matter was deemed submitted in November, 2004. In February, 2005, a Draft Decision was issued by the assigned Commissioner who found that "evidence shows SRAC prices were correct between December 2000 and March 2001, and retroactive application of the modified SRAC formula is not warranted." Various parties have submitted comments on the Draft Decision, including PG&E, SCE, a ratepayer organization and the CPUC's Office of Ratepayer Advocates, objecting to the Draft Decision. The CPUC has not yet issued a final decision in the matter and is free to accept the Draft Decision as written, modify it or reject it in its entirety. The outcome of this proceeding cannot be predicted. Even in the event of an adverse CPUC decision, the Manager has been advised by counsel that Ripon would have several meritorious legal defenses that would be available to protect Ripon from any material adverse impact. However, there is no assurance that Ripon would prevail on such defenses if called upon to assert them. If the CPUC ultimately adopts a final order imposing a retroactive modification to the SRAC formula, and a remedy based thereon is ordered or authorized, and if such final order and remedy is not reversed on appeal, California QFs including the Ripon and San Gabriel Facilities could be required to make refunds and/or accept reduced payments (by way of offset of past overpayment against future payments for power delivered) under their respective PPAs. Such refunds or reduced payments could be material for Ripon or San Gabriel, and could materially affect their ability to generate distributable cash.

Labour Relations

While labour relations at the California Cogen Facilities, the Renewable Energy Projects and the District Energy Systems have been stable to date and there have not been any disruptions in operations as a result of labour disputes with employees, the maintenance of a productive and efficient labour environment cannot be assured. In the event of a labour disruption such as a strike or lockout, the ability of the Ripon Facilities, the Renewable Energy Projects and the District Energy Systems to generate cash flow, and consequently the ability of the Fund to generate cash distributions, may be impaired.

Enforcement of Indemnities Against the Vendors under the Ripon Purchase and Sale Agreement

Pursuant to the Ripon Purchase and Sale Agreement, the vendors agreed to indemnify Countryside Holding in respect of breaches of any representations and/or warranties contained in such agreement. The vendors, however, will not be liable to pay any amounts under the indemnity provisions until the aggregate amount of all claims or losses exceeds US$1.05 million, subject to a maximum liability of US$7 million and a deductible of US$350,000, with the exception of indemnities relating to breaches of representations and/or warranties concerning certain fundamental corporate matters, tax matters and environmental matters, for which the maximum liability is limited to the cash purchase price paid by Countryside Holding under the Purchase and Sale Agreement. Further, it is not certain that the vendors will have sufficient assets to satisfy any claims for indemnification at the time an indemnification claim is made or a judgment respecting such a claim is entered. As a result, there can be no assurance that Countryside Holding will be able to obtain from the vendors under the Purchase and Sale Agreement the full amount of any damages suffered by it in respect of any breaches of representations and/or warranties by such vendors.

Duke Energy/USEY Transaction

On November 28, 2006 a Duke Energy subsidiary transferred its indirect interest in USEB to a subsidiary of USEY in consideration of, among other things, such USEY subsidiary's assumption of obligations under certain Gasco Notes under which such Duke Energy subsidiary was previously obligated. Duke Energy has substantially more revenues, assets and earnings than USEY and therefore the credit risk respecting the Gasco Notes increased due to such transaction.

Risks Related to the Structure of the Fund

Dependence on Ripon, USEB and USE Canada

The Fund is an unincorporated, open-ended, limited purpose trust which is dependent on the Manager, operations and assets of Ripon through the indirect majority ownership of its membership interests, USEB through the Allowed Secured Claim, on the management of Countryside District Energy through the indirect ownership of all of its outstanding common shares and on the management of Countryside London Cogeneration through the indirect ownership of a majority of its shares. Although the Fund intends to distribute substantially all income earned by the Fund less administrative expenses, tax liabilities and other obligations of the Fund and amounts, if any, paid by the Fund in connection with the redemption of Units, there can be no assurance regarding the amounts of income to be generated from Ripon, the Allowed Secured Claim, Countryside District Energy and Countryside London Cogeneration, and paid to the Fund which will depend upon numerous factors, some of which will be beyond the control of the Manager. Problems at USEB may affect USEB's ability to pay the Allowed Secured Claim or Countryside Canada's ability to realize full value on it.. The Fund has no ownership or governance rights respecting USEY and USEB, other than certain limited rights arising out of certain of the covenants in the USEB Settlement and applicable bankruptcy laws, and therefore has limited influence over the management of USEY and USEB. In the event of a breach of the USEB Settlement, Countryside Canada may have to attempt to realize on the security underlying the Allowed Secured Claim and there can be no assurance that the assets of USEB and its subsidiaries will be sufficient to pay the Allowed Secured Claim.

Potential Conflicts of Interest

Pursuant to the Management Agreement and the Administration Agreement, the Fund and its subsidiaries rely substantially on the Manager and the Administrator for management, administration and project development functions. See "The Management and Administration Agreements — Management Agreement" and "The Management and Administration Agreements — Administration Agreement".

There may be circumstances in which the interests of the Manager, its affiliates or entities managed by such parties may conflict with those of the Fund, Countryside Canada, its subsidiaries, the Unitholders and the Debentureholders. Although the Executives are required to devote a significant majority of their time for the benefit of Countryside Canada, Countryside Holding and its subsidiaries and to the development of projects reasonably expected to be within the acquisition criteria of the Fund, the Manager's personnel are not required to devote their time exclusively to these activities. Further, while the Manager is prohibited from providing management and administrative services to third parties other than the Fund, the Manager may develop and own energy and utility infrastructure projects for its own account or jointly with third parties, subject to its obligation to provide the Fund with a first opportunity to invest in such projects as described below. Thus, subject to the constraints described above, the Manager and its executives may engage in activities similar to the current activities of the Fund, Countryside Canada and its subsidiaries.

The Manager and its affiliates will provide Countryside Canada and its subsidiaries with the first opportunity to invest in any entity or asset that meets the investment criteria of the Fund and Countryside Canada that the Manager or its affiliates develop, own or control. The Manager shall only be free to offer such investment opportunities to third parties or to pursue them for its own account if Countryside Canada or its subsidiaries decline or are unable to pursue such opportunities.

Reliance on Third Parties

The Fund maintains no employees of its own and is reliant upon the Administrator and the Manager for the administration and management of its operating subsidiaries. The Manager and Administrator are in turn reliant upon the Executives and their respective employees for performance of the services described in the Management Agreement and the Administration Agreement. Departure of such Executives and employees may have an adverse effect on the Manager, the Administrator and the Fund.

There is no provision for Countryside Holding and Countryside Canada to terminate the Manager within the first five years of the term of the Management Agreement except in limited circumstances enumerated in the Management Agreement. After the first five years of the term of the Management Agreement, termination for reasons other than those enumerated will require payment of specified fees. See "The Management and Administration Agreements — Management Agreement —Term and Termination"

Amended Credit Facility

The Amended Credit Facility contains numerous affirmative, reporting and restrictive covenants that limit the discretion of Countryside District Energy's management with respect to certain business matters and impose burdens and potential financial risk. A failure to comply with the obligations in the Amended Credit Facility could result in a default which, if not cured or waived, could result in a termination of distributions by Countryside District Energy and permit acceleration of the relevant indebtedness, including the Countryside Canada Notes.

The USEB bankruptcy filing and USEB's payment default under the USEB Loans caused a cross-default under the Amended Credit Facility. The Fund has negotiated a waiver under which the lending syndicate has agreed to waive such cross-defaults through May 31, 2007. There can be no assurances that the lenders will agree to extend such waiver beyond such date, particularly if there are adverse changes in the business or financial condition of the Fund during such period. For this reason, the Fund is seeking a new or amended credit facility as well as other strategic alternatives. If the lenders do not extend such waiver beyond May 31, 2007 in order to provide continued access to the Amended Credit Facility, the Fund may encounter liquidity problems absent the receipt of any further installments from USEB pursuant to the USEB Settlement Agreement. If the lenders enforce their rights under the Amended Credit Facility, the Fund will be required, among other things, to suspend Unitholder distributions and funding of the London Cogeneration Project.

Public Company Litigation Risk

Because USEY and Cinergy are U.S. publicly-listed companies, any transaction or agreement between USEY or USEB, on the one hand, and the Fund or its subsidiaries, on the other (including the transactions contemplated by the Acquisition Agreement, the USEB Loan Agreement or the agreement creating the USEB Royalty Interest), may be subject to claims by the public security holders and creditors of USEY and Cinergy, which could in turn subject the Fund and/or its subsidiaries to litigation. Litigation is expensive, time consuming and may divert the attention of the Manager away from the operation of the Fund.

Tax-Related Risks

There can be no assurance that Canadian federal income tax laws and administrative policies respecting the treatment of mutual fund trusts will not be changed in a manner that adversely affects the holders of Units. If the Fund ceases to qualify as a "mutual fund trust" under the Tax Act, the income tax considerations described herein would be materially and adversely different in certain respects, including that the Securities may cease to be qualified investments for Plans. The Tax Act imposes penalties for the acquisition or holding of non-qualified investments.

On October 31, 2006, the Department of Finance (Canada) announced the "Tax Fairness Plan" whereby the income tax rules applicable to certain publicly listed trusts and partnerships will be significantly modified. In particular, certain income of (and distributions made by) these entities will be taxed in a manner similar to income earned by (and distributions made by) a corporation. These proposals will be effective for the 2007 taxation year with respect to trusts which commence public trading after October 31, 2006, but the application of the rules will be delayed to the 2011 taxation year with respects to trusts which were publicly listed prior to November 1, 2006 (although the announcement suggested that this transitional relief could be lost under certain circumstances, including the "undue expansion" of an income trust). On December 21, 2006, the Department of Finance issued for public comment the draft legislation to implement these proposals. There is no assurance that the draft legislation will be enacted in the manner proposed or at all.

On December 15, 2006, the Department of Finance (Canada) released guidance for income trusts and other flow-through entities that qualify for the four-year transitional relief. The guidance establishes objective tests with respect to how much an income trust is permitted to grow without jeopardizing its transitional relief. In general, the Fund will be permitted to issue new equity in each of the next four years equal to the greater of $50 million and a certain percentage of the Fund's market capitalization as of the end of trading on October 31, 2006 (up to 100% percent over the four years). This latter amount is cumulative to the extent it is not used in a given year and, accordingly, the Fund will be permitted to issue new equity over the next four years at least equal to its October 31, 2006 market capitalization (subject to the applicable annual limits). Market capitalization, for these purposes, is to be measured in terms of the value of the Fund's issued and outstanding publicly-traded units. If these limits are exceeded, the Fund may lose its transitional relief and thereby become immediately subject to the proposed rules.

The Fund is considering these announcements and the possible impact of the proposed rules to the Fund. The proposed rules (including the guidance released on December 15, 2006) may adversely affect the marketability of the Fund's units and the ability of the Fund to undertake financings and acquisitions, and, at such time as the proposed rules apply to the Fund, the distributable cash of the Fund may be materially reduced.

Currently, a trust will not be considered to be a mutual fund trust if it is established or maintained primarily for the benefit of non residents unless all or substantially all of its property is property other than taxable Canadian property as defined in the Tax Act. On September 16, 2004, the Minister of finance (Canada) released draft amendments to the Tax Act. Under the draft amendments, a trust would lose its status as a mutual fund trust if the aggregate fair market value of all units issued by the trust held by one or more non-resident persons or partnerships that are not Canadian partnerships is more than 50% of the aggregate fair market value of all the units issued by the trust where more than 10% (based on fair market value) of the trust's property is taxable Canadian property or certain other types of property. If the draft amendments are enacted as proposed, and if, at any time, more than 50% of the aggregate fair market value of units of the Fund were held by non-residents and partnerships other than Canadian partnerships, the Fund would thereafter cease to be a mutual fund trust. The draft amendments do not currently provide any means of rectifying a loss of mutual fund trust status. On December 6, 2004, the Department of Finance tabled a Notice of Ways and Means Motion which did not include these proposed changes. The Department of Finance indicated that the implementation of the proposed changes would be suspended pending further consultation with interested parties. The issue of ownership of units of mutual fund trusts by non-resident persons and partnerships other than Canadian partnerships was not addressed in the December 21, 2006 proposals.

There can be no assurance that the Units will continue to be qualified investments for Plans under the Tax Act. The Tax Act currently imposes penalties for the acquisition or holding of non-qualified investments.

Income fund structures generally involve significant amounts of inter company or similar debt, generating substantial interest expense, which serves to reduce earnings and therefore income tax payable. There can be no assurance that taxation authorities will not seek to challenge the amount of interest expense deducted. If such a challenge were to succeed against Countryside Canada, or Countryside holding, it could materially adversely affect the amount of cash available to the Fund for distribution to Unitholders or available to Countryside Canada to make interest payments on the Debentures. The Manager of the Fund believes that the interest expense inherent in the structure of the Fund is supportable and reasonable in light of the terms of the Countryside Canada Notes, the Debentures and the Countryside Holding Note. On October 31, 2003 the Department of Finance released, for public comment, proposed amendments to the Tax Act that relate to the deductibility of interest and other expenses for income tax purposes for taxation years commencing after 2004. In general, the proposed amendments may deny the realization of losses in respect of a business if there is no reasonable expectation that the business will produce a cumulative profit over the period that the business can reasonably be expected to be carried on. The Fund has advised counsel that it does not believe that the proposed amendments will have a material affect on the tax position of the Fund or Countryside Canada. As part of the 2005 Federal Budget, the Minister of Finance (Canada) announced that an alternative proposal to replace the proposed amendment would be released at an early opportunity.

Further, interest on the Countryside Canada Notes accrues at the Fund level for Canadian federal income tax purposes whether or not actually paid. The Declaration of Trust provides that an amount equal to the taxable income of the Fund will be distributed each year to Unitholders in order to reduce the Fund's taxable income to zero. Where interest payments on the Countryside Canada Notes are due but not paid in whole or in part, the Declaration of Trust provides that additional Units must be distributed to Unitholders in lieu of cash distributions. Unitholders will generally be required to include an amount equal to the fair market value of those Units in their Canadian federal taxable income, in circumstances when they do not directly receive a cash distribution.

Countryside District Energy's tax liability is currently reduced by tax loss carry-forwards. Should the taxing authorities reduce or eliminate such tax loss carry forwards, Countryside District Energy's tax liability may increase and adversely impact distributable cash.

United States Tax-Related Risks

There can be no assurance that U.S. federal income tax laws and the IRS administrative policies respecting the U.S. tax consequences described herein will not be changed in a manner that adversely affects Unitholders. The Fund has obtained advice and opinions from U.S. tax counsel on certain U.S. federal income tax matters; however, the Fund has not sought or received a formal tax opinion from U.S. tax counsel with regard to all U.S. federal income tax matters, including tax consequences of the Countryside Holding Note, which may affect the Fund.

Countryside Holding Note

The following discussion describes certain U.S. federal income tax consequences that could result in a reduction in the amount of distributions that Countryside Canada would otherwise receive from Countryside Holding and could consequently result in a reduction in the cash flow of the Fund that would otherwise be available for distribution to Unitholders. Countryside Holding intends to treat the Countryside Holding Note as debt for U.S. federal income tax purposes and (subject to the discussion below regarding the earnings stripping rules) to claim deductions for all of the interest on the Countryside Holding Note in computing its income for U.S. federal income tax purposes. The Fund believes that the interest rate being charged on the Countryside Holding Note has been determined in an arm's length manner under the relevant facts and circumstances. While it is possible that the Internal Revenue Service (''IRS'') could take a contrary position, the Fund believes, based on advice of U.S. tax counsel, that Countryside Holding's position that the Countryside Holding Note is properly treated as debt, rather than equity, for U.S. federal income tax purposes is supported by existing legal authority as applied to the relevant facts and circumstances reviewed by U.S. tax counsel relating to the Countryside Holding Note. If the IRS successfully challenged Countryside Holding's treatment of the Countryside Holding Note as debt for such purposes, then otherwise deductible interest would be treated as non-deductible distributions and the disallowance of these interest deductions could increase Countryside Holding's U.S. federal income tax liability. If the IRS successfully challenged the interest rate as excessive on the Countryside Holding Note, Countryside Holding would not be able to fully deduct interest paid on such note and the disallowance of these interest deductions could increase Countryside Holding's U.S. federal income tax liability. Any such increase in Countryside Holding's U.S. federal income tax liability could adversely affect its ability to make interest and principal payments on the Countryside Holding Note and could also reduce the amount of the distributions which Countryside Canada would otherwise receive from Countryside Holding, and this could reduce the cash flow of the Fund that would otherwise be available for distribution to Unitholders and Debentures.

The earnings stripping rules under Section 163(j) of the United States Internal Revenue Code of 1986, as amended (the "Code"), may limit the ability of Countryside Holding to deduct all or a portion of the interest paid on the Countryside Holding Note. Generally, under these rules, the ability of Countryside Holding to deduct interest paid on the Countryside Holding Note will be limited if (1) the debt to equity ratio of Countryside Holding exceeds 1.5 to 1 and (2) its net interest expense (the interest paid by Countryside Holding on all debt, including the Countryside Holding Note, less its interest income) exceeds 50% of its adjusted taxable income (generally, U.S. federal taxable income before net interest expense, depreciation, amortization and taxes). The amount of the disallowed deduction would be the interest expense on the Countryside Holding note exceeding the 50% threshold. If all or a portion of the deduction for interest on the Countryside Holding Note for a taxable year is disallowed by Code Section 163(j), the amount disallowed will be carried forward and treated as interest paid or accrued in the succeeding taxable year. Such interest, together with all other interest paid or accrued by Countryside Holding on all of its debt in the succeeding taxable year, would then be tested under Code Section 163(j) in such succeeding taxable year. In addition, there can be no assurance that future changes to the Code and the regulations thereunder will not otherwise restrict or eliminate the ability of Countryside Holding to claim a deduction for U.S. federal income tax purposes for interest paid on the Countryside Holding Note. There have been some recent proposals in this regard. An additional restriction on or elimination of the ability of Countryside Holding to claim deductions for interest payments on the Countryside Holding Note could increase the U.S. federal income tax liability of Countryside Holding. Any such increase in U.S. federal income tax liability could reduce the amount of the distributions which Countryside Canada would otherwise receive from Countryside Holding and this could reduce the cash flow of the Fund that would otherwise be available for distribution to Unitholders and Debentureholders. The debt to equity ratio of Countryside Holding currently is less than 1.5 to 1, and thus the limitations of Code Section 163(j) are not expected to currently apply. Because the tests of Code Section 163(j) are applied for each taxable year, no assurance can be given that the limitations of Code Section 163(j) would not apply in the future.

USEB Loan and USEB Royalty

Countryside Canada may become liable to pay or remit amounts as or on account of withholding tax in respect of its acquisition, making or holding of the USEB Loans (including the receipt of interest thereon) or any other similar loans made by Countryside Canada to USEB. In such case funds available for distribution by Countryside Canada with respect to the common shares of Countryside Canada and for payments with respect to the Countryside Canada Notes may be significantly reduced.

The Fund has been advised by U.S. tax counsel that interest paid on the USEB Loans should be deductible to USEB and should not be subject to U.S. withholding tax.

However, there is a risk that the IRS could successfully challenge such treatment, resulting in some or all of the interest on the USEB Loans being non-deductible (materially increasing USEB's U.S. federal income tax liability) and some or all of such interest being subject to U.S. withholding tax of 10% to 30%. As a result, the amount of funds available for distribution to Unitholders and Debentureholders could be reduced.

Financial Leverage and Restrictive Covenants

Borrowings, including the Amended Credit Facility, will introduce leverage into the Fund's business will increase the level of financial risk to the Fund, and to the extent that interest rates are not fixed or that borrowings are refinanced at different rates, will increase the sensitivity of distributable cash to interest rate levels.

Adequacy of Capital Resources and Working Capital

Future acquisitions by the Fund, expansions of the Fund's assets and other capital expenditures and working capital requirements will be financed through the issuance of Units or securities exchangeable for Units, by increasing the consolidated indebtedness of the Fund, from cash flows of the Fund, or by some combination thereof. There can be no assurance that sufficient capital will be available on acceptable terms to fund acquisitions, capital expenditures, expansion projects or working capital requirements.

Exchange Rate Fluctuations

A majority of the Fund's costs and its financial obligations to its lenders and Unitholders are denominated in Canadian dollars. It's obligation to Debenture holders is denominated in US dollars.

The Allowed Secured Claim is denominated in U.S. dollars requiring USEB to make payments on the Allowed Secured Claim in U.S. dollars. Unfavourable movements in the exchange rate may reduce the value, in Canadian dollars, of payments on the Allowed Secured Claim received by Countryside Canada. The Manager is monitoring the exchange rate to determine whether to purchase a hedging arrangement to mitigate against such risk.

The Cogen Facilities' revenues derived from PPAs and steam sale agreements are denominated in US dollars as is the expected resultant US dollar denominated distributable cash from the Cogen Facilities. The Manager has entered into a foreign exchange option to mitigate the effect of the resultant foreign exchange risk related to the portion of US dollar revenues required to meet its Canadian dollar obligations and anticipated Unitholder distributions. To the extent such foreign exchange options or similar hedging arrangements are not maintained and exchange rates are unfavourable, the Fund's ability to pay cash distributions to Unitholders may be affected.

Nature of Units

Each Unit represents an equal undivided beneficial interest in the Fund. The Fund's sole material assets are the common shares of Countryside Canada and the Countryside Canada Notes. The Units do not represent debt instruments and there is no principal amount owing to Unitholders under the Units. The Units do not represent shares in any direct or indirect subsidiary of the Fund or any other company. The Units do not represent a direct investment in Ripon, the Allowed Secured Claim, the District Energy Systems or the London Cogen Facility. The price per Unit is a function of anticipated distributable cash of the Fund, which may change.

The Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporations Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Fund is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Distribution of Securities on Redemption or Termination of the Fund

Upon a redemption of Units or termination of the Fund, the Trustees may distribute the common shares of Countryside Canada and Countryside Canada Notes directly to Unitholders, subject to obtaining all required regulatory approvals. There is currently no market for common shares of Countryside Canada or the Countryside Canada Notes. In addition, neither the common shares of Countryside Canada nor the Countryside Canada Notes are expected to be freely tradable or listed on any stock exchange. Common shares of Countryside Canada and/or Countryside Canada Notes, as the case may be, so distributed may not be qualified investments for trusts governed by Plans, depending upon the circumstances at the time.

Fluctuations, Delays and Suspensions of Distributions

Cash distributions are not guaranteed and distributions by the Fund will fluctuate. They will depend on numerous factors some of which will be beyond the control of the Fund.

Payments by Countryside Canada to the Fund or Ripon (through Ripon Power and Countryside Holding), Countryside District Energy, Countryside London Cogeneration or USEB to Countryside Canada may be delayed, reduced or suspended by, among other things, restrictions imposed by lenders, issues with the financial or operational performance of Ripon, the Renewable Energy Projects or the District Energy Systems, disruptions in service, fuel disruptions, regulatory or legislative actions, the establishment of reserves for expenses, working capital requirements, future capital requirements and the deductibility for Canadian and U.S. tax purposes, respectively, of payments on the Countryside Canada Notes, the Countryside Holding Note and the Allowed Secured Claim. If the Lenders' waiver the cross-default under the Amended Credit Facility expires and the lenders enforce their rights, the Fund will be required, among other things, to suspend Unitholder distributions. The Lenders and the Manager are engaged in discussions regarding a permanent waiver, a waiver extension and a potential refinance of the Amended Credit Facility. There is no assurance that such discussions will be successful. Any such delay, reduction or suspension could have an adverse effect on distributions by the Fund and consequently on the market value of the Units.

Enforcement of The Allowed Secured Claim

If USEB does not comply with the USEB Settlement, any proceeding by Countryside Canada to enforce its rights under the USEB Settlement and as to the security underlying the Allowed Secured Claim will have to be brought in the Bankruptcy Court and appropriate jurisdictions in the United States and will be subject to federal bankruptcy laws, the rulings of the Bankruptcy Court, the applicable state's uniform commercial code and common law and equitable principles which may limit, restrict, inhibit or delay Countryside Canada's enforcement efforts. Countryside Canada's rights to enforce the Allowed Secured Claim against the assets or equity interests respecting the Countryside, Morris and Brookhaven projects may be subject to YESCO's rights as a subordinated secured lender respecting such projects. The assertion of YESCO of such rights or defenses may affect Countryside Canada's ability to enforce its rights under the Allowed Secured Claim in a manner materially adverse to Countryside Canada and the Fund. The Manager is advised that YESCO has not filed a claim in the USEB Bankruptcy before the claims bar date and therefore YESCO should not be able to assert a claim in the USEB Bankruptcy.

Dilution of Existing Unitholders and Debentureholders

The Declaration of Trust authorizes the Fund to issue an unlimited number of Units or securities exchangeable or convertible into Units for that consideration and on those terms and conditions as are established by the Trustees without the approval of Unitholders or Debentureholders. The issuance of additional Units or securities exchangeable or convertible into Units, including LTIP interests in Development Assets issued to the Manager in accordance with the Management Agreement, may dilute a Unitholder's or a Debentureholder's investment in the Fund and reduce cash distributions per Unit and therefore reduce the trading price of a Unit or a Debenture or the consideration per Unit received in a sale of the Fund or its assets.

Under Amendment No. 1 of the Management Agreement, the Fund and the Manager have agreed that on the earlier of June 29, 2007 or a Change of Control the Manager will transfer its LTIP interest (or a portion thereof) in Ripon Power for a combination of Fund units and cash. While as a result of such transaction, Countryside US Holding will acquire the Manager's LTIP interest in Ripon Power and the rights to cash distributions associated therewith, it is possible that such transaction may be dilutive to a Unitholder or a Debentureholder in the manner described above.

Restrictions on Potential Growth

The payout by Ripon under the Countryside Holding Note, and Countryside District Energy and Countryside London Cogeneration of a substantial portion of their operating cash flow to Countryside Canada will make additional capital and operating expenditures dependent on increased cash flow or additional financing in the future. Lack of those funds could limit the future growth of Ripon, Countryside Acquisition and Countryside District Energy and Countryside London Cogeneration .

Ratings

The Units of the Fund currently do not have a rating because the Fund chose not to renew its contract with DBRS. The lack of such a rating may have an adverse effect on the market price of the units.

Risks Related Specifically to the Debentures

Trading Market for Debentures

The Debentures may trade at a discount from their initial public offering price depending on prevailing interest rates, the market for similar securities, the performance of Countryside Canada and other factors. No assurance can be given as to whether an active trading market will be maintained for the Debentures. To the extent that an active trading market for the Debentures is not maintained, the liquidity and trading prices for the Debentures may be adversely affected.

Prior Ranking Indebtedness

The Debentures are subordinate to all Senior Secured Indebtedness. The Debentures are also be effectively subordinate to claims of trade creditors of Countryside Canada's direct or indirect subsidiaries except to the extent Countryside Canada is a creditor of such subsidiaries ranking at least *paripassu* with such other creditors. See "Description of the Debentures — Subordination".

Absence of Covenant Protection

The Indenture does not restrict Countryside Canada or any of its subsidiaries from incurring additional indebtedness or from mortgaging, pledging or charging its assets to secure any indebtedness. The Indenture does not contain any provisions specifically intended to protect holders of the Debentures in the event of a future leveraged transaction involving Countryside Canada or any of its subsidiaries.

Redemption Prior to Maturity

The Debentures may be redeemed, at the option of Countryside Canada, on and after October 31, 2008 and prior to the Maturity Date in whole or in part, at the redemption prices set forth in this short form prospectus, together with any accrued and unpaid interest. Holders of Debentures should assume that this redemption option will be exercised if Countryside Canada is able to refinance at a lower interest rate or it is otherwise in the interest of Countryside Canada to redeem the Debentures.

Inability of Fund to Purchase Debentures

Countryside Canada is required to offer to purchase all outstanding Debentures upon the occurrence of a Change of Control. However, it is possible that following a Change of Control, Countryside Canada will not have sufficient funds at that time to make the required purchase of outstanding Debentures or that restrictions contained in other indebtedness will restrict those purchases. See "Description of Debentures — Put Right Upon a Change of Control".

Exchange Right Following Certain Transactions

In the event of certain transactions, pursuant to the terms of the Indenture, each Debenture will become exchangeable for securities, cash or property receivable by a holder of Units in the kind and amount of securities, cash or property into which the Debenture was exchangeable immediately prior to the transaction. This change could substantially lessen or eliminate the value of the exchange privilege associated with the Debentures in the future.

Restrictions on Certain Unitholders and Liquidity of Units

The Declaration of Trust imposed various restrictions on Unitholders (which will also apply to Debentureholders). Non-resident Unitholders are prohibited from beneficially owning more than 49% of Units and the Trustees have the authority to limit beneficial ownership of Units to no more than 100 United States persons. As a result, these restrictions may limit the demand for Units from certain Unitholders and thereby adversely affect the liquidity and market value of the Units held by the public.

DESCRIPTION OF THE FUND

Declaration of Trust

The Fund is an unincorporated, open-ended, limited purpose trust established under the laws of the Province of Ontario pursuant to the Declaration of Trust. It is intended that the Fund will qualify as a "mutual fund trust" for the purposes of the Tax Act. The following is a summary of the material attributes and characteristics of the Units and certain provisions of the Declaration of Trust, which summary is not intended to be complete. Reference is made to the Declaration of Trust for a complete description of the Units and the full text of its provisions.

Activities of the Fund

The Declaration of Trust provides that the Fund is restricted to:

(i) acquiring, investing in, transferring, disposing of and otherwise dealing with securities of Countryside Canada and other corporations, partnerships, trusts or other persons engaged, directly or indirectly, in the business of energy generation, as well as activities ancillary thereto, and such other investments as the Trustees may determine;

(ii) temporarily holding cash in interest-bearing accounts, short-term government debt or short-term investment grade corporate debt for the purposes of paying the expenses and liabilities of the Fund, paying amounts payable by the Fund in connection with the redemption of any Units or other securities of the Fund and making distributions to Unitholders;

(iii) issuing Units and other securities of the Fund (including securities convertible or exchangeable into Units, or warrants, options or other rights to acquire Units or other securities of the Fund) (a) for obtaining funds to conduct the activities of the Fund, including raising funds for acquisitions and development; (b) in satisfaction of any non-cash distribution; or (c) pursuant to any distribution reinvestment plans, long-term incentive plan or other compensation plans, if any, established by the Fund, Countryside Canada or their respective subsidiaries;

(iv) issuing debt securities (including debt securities convertible into, or exchangeable for, Units or other securities of the Fund) or otherwise borrowing and mortgaging, pledging, charging, granting a security interest in or otherwise encumbering any of its assets as security;

(v) guaranteeing the payment of any indebtedness, liability or obligation of the Fund, Countryside Canada or any of their respective subsidiaries or the performance of any obligation of any of them, and mortgaging, pledging, charging, granting a security interest in or otherwise encumbering all or any part of its assets as security for such guarantee, and subordinating its rights under the Countryside Canada Notes to other indebtedness;

(vi) disposing of any part of the assets of the Fund;

(vii) issuing or redeeming rights and Units pursuant to any Unitholder rights plan adopted by the Fund;

(viii) repurchasing securities issued by the Fund, subject to the provisions of the Declaration of Trust and applicable laws;

(ix) satisfying the obligations, liabilities or indebtedness of the Fund; and

(x) undertaking all other usual and customary actions for the conduct of the activities of the Fund in the ordinary course as are approved by the Trustees from time to time, or as are contemplated by the Declaration of Trust, provided the Fund will not undertake any activity, take any action, omit to take any action or make any investment which would result in the Fund not being considered a "mutual fund trust" for purposes of the Tax Act.

Issuance of Units

The Declaration of Trust provides that Units may be issued at those times, to those persons, for that consideration and on the terms and conditions that the Trustees determine. Units may be issued in satisfaction of any non-cash distribution of the Fund to Unitholders on a *pro rata* basis. The Declaration of Trust also provides that immediately after any *pro rata* distribution of Units to all Unitholders in satisfaction of any non-cash distribution, the number of outstanding Units will be consolidated so that each Unitholder will hold after the consolidation the same number of Units as the Unitholder held before the non-cash distribution. In this case, each certificate representing a number of Units prior to the non-cash distribution is deemed to represent the same number of Units after the non-cash distribution and the consolidation. Where amounts so distributed represent income, non-resident holders will be subject to withholding tax thereon and the consolidation will not result in those non-resident Unitholders holding the same number of Units. Such non-resident Unitholders will be required to surrender the certificates, if any, representing their original Units in exchange for a certificate representing their post-consolidation Units.

The Trustees may refuse to allow the issue or register the transfer of any Units, where such issuance or transfer would, in their opinion, adversely affect the treatment of the Fund or the companies in which it invests under applicable Canadian and/or U.S. tax legislation. See "— Limitation on Ownership".

Cash Distributions

The Fund intends to make monthly cash distributions on a per Unit basis to the Unitholders equal to a *pro rata* share of interest and principal repayments on the Countryside Canada Notes and dividends or distributions on or in respect of the common shares of Countryside Canada owned by the Fund, less:

- administrative expenses and other obligations of the Fund;
- amounts which may be paid by the Fund in connection with any cash redemptions of Units; and
- any tax liability of the Fund.

Under the terms of the Countryside Canada Notes, interest is accrued at 10.95% and is to be paid monthly on the 30th day following each calendar month that such notes are outstanding. The Fund will make additional distributions in excess of the monthly distributions during the year to the extent of available cash, as determined by the Trustees.

Any income of the Fund which is applied to any cash redemptions of Units, or is otherwise unavailable for cash distribution will be distributed to Unitholders in the form of additional Units. Those additional Units will be issued under applicable exemptions under applicable securities laws, discretionary exemptions granted by applicable securities regulatory authorities or a prospectus or similar filing. See "— Issuance of Units".

Monthly distributions will be payable to Unitholders of record on the last business day of each month and are expected to be paid to Unitholders on or about the 30th day of the following month. In all events, any cash, securities, or other property received by the Fund upon the sale, exchange, redemption, cancellation, or other disposition of securities of Countryside Canada will, after appropriate deductions for expenses, be promptly distributed.

Holders of Units who are non-residents of Canada will be required to pay all withholding taxes payable in respect of any distributions of income by the Fund, whether those distributions are in the form of cash or additional Units. Non-residents of Canada should consult their own tax advisors regarding the tax consequences of investing in the Units.

Redemption Right

Units are redeemable at any time on demand by the holders. As the Units will be issued in book entry form (see "— Book-Entry Only System"), a Unitholder who wishes to exercise the redemption right will be required to obtain a redemption notice form from the Unitholder's investment dealer or broker who will be required to deliver the completed redemption notice form to the Fund at its head office and to CDS which will, in turn, be required to forward it to the Fund. Upon receipt of the redemption notice by the Fund, all rights to and under the Units tendered for redemption will be surrendered. If the holder has elected a redemption in cash, subject to the limitations discussed below, the holder will be entitled to receive a price per Unit (the "redemption price") equal to the lesser of:

- 90% of the "market price" of the Units on the principal market on which the Units are quoted for trading during the 10-trading day period ending on the date on which the Units were surrendered for redemption (the "redemption date"); and
- 100% of the "closing market price" on the principal market on which the Units are quoted for trading on the redemption date.

For the purposes of this calculation, "market price" will be an amount equal to the weighted average of the closing price of the Units for each of the trading days on which there was a closing price, provided that:

- if the applicable exchange or market does not provide a closing price, but only provides the highest and lowest prices of the Units traded on a particular day, the "market price" will be an amount equal to the weighted average of the highest and lowest prices for each of the trading days on which there was a trade; and

- if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the "market price" will be the weighted average of the following prices established for each of the 10 trading days: (i) the weighted average of the last bid and last asking prices of the Units for each day there was no trading; (ii) the closing price of the Units for each day that there was trading if the exchange or market provides a closing price; and (iii) the weighted average of the highest and lowest prices of the Units for each day that there was trading if the market provides only the highest and lowest prices of Units traded on a particular day.

The "closing market price" for the purpose of the foregoing calculation will be:

- an amount equal to the closing price of the Units if there was a trade on the date and the exchange or market provides a closing price;

- an amount equal to the weighted average of the highest and lowest prices of the Units if there was trading and the exchange or other market provides only the highest and lowest prices of Units traded on a particular day; or

- the weighted average of the last bid and last asking prices of the Units if there was no trading on that date.

The total redemption price payable by the Fund in respect of all Units surrendered for redemption during any calendar month will be satisfied by way of a cash payment no later than the last day of the month following the month in which the Units were tendered for redemption, provided that Unitholders will not be entitled to receive cash upon the redemption of their Units if:

- the total amount payable by the Fund in respect of those Units and all other Units tendered for redemption in the same calendar month exceeds $50,000, provided that the Trustees may, in their sole discretion, waive this limitation in respect of all Units tendered for redemption in any calendar month;

- at the time the Units are tendered for redemption, the outstanding Units are not listed for trading on a stock exchange or traded or quoted on another market which the Trustees consider, in their sole discretion, provides representative fair market value prices for the Units; or
- the normal trading of Units is suspended or halted on any stock exchange on which the Units are listed (or, if not listed on a stock exchange, on any market on which the Units are quoted for trading) on the redemption date or for more than five trading days during the 10-day trading period commencing immediately after the redemption date.

If a Unitholder is not entitled to receive cash upon the redemption of Units as a result of one or more of the foregoing limitations, then each Unit tendered for redemption will, subject to any applicable regulatory approvals, be redeemed by way of a distribution in *specie* of a *pro rata* number of common shares of Countryside Canada and Countryside Canada Notes held by the Fund and a *pro rata* share of the Fund's cash and other property (less a *pro rata* share of any accrued liabilities of the Fund). The Fund will be entitled to all interest paid on the Countryside Canada Notes and the distributions paid on the common shares of Countryside Canada on or before the date of the distribution in *specie*. A Unitholder will be entitled to interest that has accrued on the Countryside Canada Notes and has not been paid to the Fund on or before the date of the distribution in *specie*. Where the Fund makes a distribution in *specie* of a *pro rata* number of common shares of Countryside Canada and Countryside Canada Notes and any cash and other property held by the Fund on the redemption of Units of a Unitholder, the Fund currently intends to designate to that Unitholder any income or capital gain realized by the Fund as a result of the distribution of those properties to the Unitholder.

It is anticipated that the redemption right described above will not be the primary mechanism for Unitholders to dispose of their Units. Common shares of Countryside Canada and/or Countryside Canada Notes which may be distributed in *specie* to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in common shares of Countryside Canada or Countryside Canada Notes and they may be subject to resale restrictions under applicable securities laws. Common shares of Countryside Canada, Countryside Canada Notes or other property so distributed may not be qualified investments for trusts governed by a Plan, depending upon the circumstances at the time.

Meetings of Unitholders

The Declaration of Trust provides that meetings of Unitholders will be called and held annually for the election of Trustees and the appointment of auditors of the Fund. The Declaration of Trust provides that the Unitholders will be entitled to pass resolutions that will bind the Fund only with respect to:

- the appointment or removal of Trustees;

- the appointment or removal of nominees of the Fund chosen by the Unitholders to serve as directors of Countryside Canada (except filling casual vacancies);

- the appointment or removal of the auditors of the Fund;

- the appointment of an inspector to investigate the performance by the Trustees in respect of their respective responsibilities and duties in respect of the Fund;

- the approval of amendments to the Declaration of Trust (but only in the manner described below under "— Amendments to the Declaration of Trust");

- the termination of the Fund;

- the sale of all or substantially all of the assets of the Fund;

- the exercise of certain voting rights attached to the securities of Countryside Canada held by the Fund;

- the termination of the Book-Entry System with respect to the Units;

- the dissolution of the Fund prior to the end of its term; and

- any other matters required by securities law, stock exchange rules or other laws or regulations to be submitted to Unitholders for their approval.

No other action taken by Unitholders or any other resolution of the Unitholders at any meeting will in any way bind the Trustees.

A resolution electing or removing nominees of the Fund to serve as directors of Countryside Canada and a resolution appointing or removing the Trustees or the auditors of the Fund must be passed by a simple majority of the votes cast by Unitholders. Any resolution on a matter which is required by securities law, stock exchange rules or other laws or regulations will be required to be passed in accordance with the requirements of such laws, rules or regulations. The balance of the foregoing matters must be passed by a special resolution requiring two-thirds approval (the "Special Resolution").

A meeting of Unitholders may be convened at any time and for any purpose by the Trustees and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 10% of the Units then outstanding by a written requisition. A requisition must state in reasonable detail the business proposed to be transacted at the meeting.

Unitholders may attend and vote at all meetings of the Unitholders either in person or by proxy and a proxy-holder need not be a Unitholder. Two persons present in person or represented by proxy and representing in total at least 10% of the votes attached to all outstanding Units will constitute a quorum for the transaction of business at all meetings.

The Declaration of Trust contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders.

Amendments to the Declaration of Trust

The Declaration of Trust may be amended or altered from time to time by the Trustees with the consent of the Unitholders by Special Resolution. The Trustees may, without the approval of the Unitholders, make certain amendments to the Declaration of Trust, including amendments:

- for the purpose of ensuring continuing compliance with applicable laws, regulations, requirements or policies of any governmental authority having jurisdiction over the Trustees or over the Fund;
- for the sole purpose of providing additional protection for the Unitholders, provided that the Trustees receive a legal opinion from legal counsel to this effect and that such additional protection is the sole purpose of such amendment;
- to remove any conflicts or inconsistencies in the Declaration of Trust or to make minor corrections which, in the opinion of the Trustees, are necessary or desirable and not prejudicial to the Unitholders;
- which, in the opinion of the Trustees, are necessary or desirable as a result of changes in Canadian federal or provincial or United States federal or state taxation laws; and
- to ensure that the Fund continues to qualify as a "mutual fund trust" for purposes of the Tax Act.

Notwithstanding the previous sentence, the Trustees may not (without a Special Resolution) amend the Declaration of Trust in a manner which would result in the Fund not being considered a "mutual fund trust" for purposes of the Tax Act.

Term of the Fund

The Fund has been established for a term ending 21 years after the date of death of the last surviving issue of Her Majesty, Queen Elizabeth II, alive on February 16, 2004. On a date selected by the Trustees which is not more than two years prior to the expiry of the term of the Fund, the Trustees are obligated to commence to wind-up the affairs of the Fund so that it will terminate on the expiration of the term. In addition, at any time prior to the expiry of the term of the Fund, the Unitholders may by a Special Resolution require the Trustees to commence to wind up the affairs of the Fund.

The Declaration of Trust provides that, upon being required to commence to wind-up the affairs of the Fund, the Trustees will give notice to the Unitholders, which notice will designate the time or times at which Unitholders may surrender their Units for cancellation and the date at which the register of Units will be closed. After the date the register is closed, the Trustees will proceed to wind-up the affairs of the Fund as soon as may be reasonably practicable. Subject to any direction to the contrary in respect of a termination authorized by a resolution of the Unitholders, the Trustees will sell and convert into money the common shares of Countryside Canada, Countryside Canada Notes, and all other assets comprising the Fund in one transaction or in a series of transactions at public or private sales and do all other acts appropriate to liquidate the Fund. After paying, retiring, discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Fund and providing for indemnity against any other outstanding liabilities and obligations, the Trustees will distribute the remaining part of the proceeds of the sale of the common shares of Countryside Canada, Countryside Canada Notes and other assets comprising the Fund among the Unitholders in accordance with their *pro rata* interests. If the Trustees are unable to sell all or any of the common shares of Countryside Canada, Countryside Canada Notes or other assets comprising the Fund by the date set for termination, the Trustees may distribute the remaining common shares of Countryside Canada, the Countryside Canada Notes or other assets in *specie* directly to the Unitholders in accordance with their pro rata interests, subject to obtaining all required regulatory approvals.

Take-over Bids

The Declaration of Trust contains provisions to the effect that if a take-over bid is made for all of the Units and the offeror acquires not less than 90% of all outstanding Units (excluding Units held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror), the offeror will be entitled to acquire all Units held by Unitholders who did not accept the take-over bid on the terms offered by the offeror.

Information and Reports

The Fund will furnish to the Unitholders, in accordance with applicable securities laws, all financial statements of the Fund (including quarterly and annual financial statements) and other reports as are from time to time required by applicable law, including prescribed forms needed for the completion of the Unitholders' tax returns under the Tax Act and equivalent provincial legislation.

Prior to each meeting of Unitholders, the Trustees will provide to the Unitholders (along with notice of the meeting) all information as is required by applicable law and by the Declaration of Trust to be provided to the Unitholders.

Trustees of the Fund and the directors, senior officers and other insiders of each of Countryside Canada and any other entities owned directly or indirectly by the Fund will be required to file insider reports and comply with insider trading provisions under applicable Canadian securities legislation in respect of trades made by such persons in Units of the Fund.

USEB has undertaken to provide the Fund with certain financial information under the USEB Settlement.

Book Entry Only System

Registration of interests in and transfers of Units will be made only through a book-based system administered by CDS. On the date of closing of the Offering, the Trustees will deliver to CDS one or more certificates representing the total number of Units subscribed for under the Offering. Units must be purchased, transferred and surrendered for redemption through a participant in the CDS depository service (a "CDS participant"). All rights of the Unitholders must be exercised through, and all payments or other property to which the Unitholder is entitled will be made or delivered by, CDS or the CDS participant through which the Unitholder holds the Units. Upon a purchase of any Units, the Unitholder will receive only a customer confirmation from the registered dealer which is a CDS participant and from or through which the Units are purchased.

The ability of a beneficial owner of Units to pledge those Units or otherwise take action with respect to the Unitholder's interest in those Units (other than through a CDS participant) may be limited due to the lack of a physical certificate.

The Fund has the option of terminating registration of the Units through the book entry system, in which case certificates for the Units in fully registered form would be issued to beneficial owners of those Units or their nominees.

Limitations on Ownership

In order for the Fund to maintain its status as a ''mutual fund trust'' under the Tax Act, the Fund must not be established or maintained primarily for the benefit of non-residents of Canada within the meaning of the Tax Act. Accordingly, at no time may non-residents of Canada be the beneficial owners of more than 49% of the Units (on either a non-diluted or fully-diluted basis). In addition, in order for the Fund to be exempt from the registration requirements as an investment company under the United States Investment Company Act of 1940, as amended (the ''1940 Act''), at no time may more than 100 U.S. persons (using the principles for counting set forth in Section 3(c)(1) of the 1940 Act) be the beneficial owners of the Units, nor may any U.S. person be the beneficial owner of more than 10% of the Units. Consequently, Countryside Canada may require declarations as to the jurisdictions in which beneficial owners of Debentures are resident. If Countryside Canada becomes aware that either of the foregoing limitations may be contravened, the directors of Countryside Canada will make a public announcement and will not accept a subscription for Debentures from or issue or register a transfer of

Debentures to a person unless the person provides a declaration that the person is not a non-resident of Canada. If, notwithstanding the foregoing, the Fund becomes aware that more than 49% of the Units are held by non-residents (on either a non-diluted or fully-diluted basis), that more than 100 U.S. persons are beneficial owners of Units (on either a non-diluted or fully-diluted basis), or that any U.S. person is the beneficial owner of more than 10% of the Units (on either a non-diluted or fully-diluted basis), the Fund may send a notice to the non-resident or U.S. holders, as applicable, chosen in inverse order to the order of acquisition or registration or in any manner as Countryside Canada may consider equitable and practicable, requiring them to sell their Units or a portion of their Units within a specified period of not less than 60 days. If the Unitholders receiving the notice have not sold the specified number of Units or provided the Fund with satisfactory evidence that they are not non-residents within that period, the Fund may, on behalf of those Unitholders, sell those Units and, in the interim, will suspend the rights attached to those Units. Upon that sale, the affected holders will cease to be holders of the Units and their rights will be limited to receiving the net proceeds of the sale.

Monitoring of Limitation of Ownership

Because all of the units are held in the name of The Canadian Depository for Securities Limited ("CDS"), it is extremely difficult to monitor ownership by U.S. residents or pension funds on an ongoing basis without undue expense and burden to the Fund. However, the employees of the Fund and U.S. Energy Systems, Inc., the Fund's promoter, were notified at the time the Fund's initial public offering was consummated regarding limitations on ownership of Fund Units by U.S. residents. Further, such employees have been advised that U.S. based employees of both companies may not own Fund Units (except for the three current Executives) and may not encourage U.S. residents to purchase Fund Units. In the event the Trustees or the Manager of the Fund learn of transactions or activities which potentially may result in Unit ownership in violation of the limitations described above, it may take further investigatory and remedial actions including those described above.

DESCRIPTION OF THE DEBENTURES

The Debentures are issued under an indenture, dated as of November 14, 2005 (the "Indenture"), between the Fund, Countryside Canada and the Debenture Trustee.

The Debenture Trustee also acts as the trustee for the Countryside Canada Notes issued pursuant to the terms of the Countryside Canada Note Indenture. See "Description of Countryside Canada — Countryside Canada Notes".

The following is a description of the terms of the Indenture, a copy of is filed with the Canadian securities regulatory authorities. Capitalized terms used in this "Description of Debentures" section and not otherwise defined have the meanings set forth in the Indenture. The following summary of certain provisions of the Indenture is subject to, and is qualified in its entirety by reference to, all the provisions of the Indenture.

General

The Debentures are limited in the aggregate principal amount to a maximum of US$55 million. The Debentures are dated as of November 14, 2005 and will mature on October 31, 2012. The Debentures are issued in denominations of US$1,000 and integral multiples thereof. The Debentures bear interest from the date of issue at a rate of 6.25% per annum payable semi-annually in arrears on April 30 and October 31 in each year, commencing on April 30, 2006. The interest on the Debentures is payable in lawful money of the United States of America, or at the option of Countryside Canada, by delivery of Units of the Fund to the Debenture Trustee for sale through the facilities of a registered broker/dealer, in which event holders of Debentures will be entitled to receive a cash payment equal to the interest owed from the proceeds of the sale of the requisite number of Units by the Debenture Trustee. The first interest payment will include interest from the date of closing of the Offering up to, but excluding, April 30, 2006.

The principal on the Debentures is payable in lawful money of the United States of America or, at the option of Countryside Canada and subject to applicable regulatory approval, by delivery of Units as further described below under "— Payment Upon Redemption or Maturity" and "— Redemption and Purchase".

The Debentures are direct obligations of Countryside Canada and are not secured by any mortgage, pledge, hypothec or other charge and rank senior to other liabilities of Countryside Canada as described under "Subordination" below. The Indenture does not restrict Countryside Canada from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its properties to secure any indebtedness.

The Debentures are transferable at, and may be presented for exchange at, the principal offices of the Debenture Trustee in Toronto, Ontario.

Exchange Privilege

The Debentures are exchangeable at the holder's option into fully-paid, non-assessable and freely-tradeable Units at any time prior to 5:00 p.m. (Toronto time) on the earlier of the Maturity Date and the business day immediately preceding the date specified by Countryside Canada for redemption of the Debentures, at an exchange price of $10.75 per Unit, being an exchange ratio of 109.4884 Units for each US$1,000 principal amount of Debentures. No adjustment will be made to the record dates for distribution of Units issuable on exchange. Debenture holders exchanging their Debentures will receive accrued and unpaid interest thereon up to, but excluding, the date of exchange. Pursuant to the Indenture, a Debenture shall be deemed to be surrendered for exchange on the date on which it is so surrendered in accordance with the provisions of the Indenture and, in the case of a Debenture so surrendered by post or other means of transmission, on the date on which it is received by the Debenture Trustee, provided that if a Debenture is surrendered for exchange on a day on which the register of Units is closed, the Debentureholder entitled to receive Units shall become the holder of record of such Units as at the date on which such register is next reopened. No Debentures may be exchanged during the five business days preceding the last day of April and October in each year commencing April 30, 2006.

Subject to the provisions thereof, the Indenture provides for the adjustment of the Exchange Price in certain events including: (a) the subdivision or consolidation of the outstanding Units; (b) the distribution of Units (or securities convertible into or exchangeable for Units) to all or substantially all holders of Units by way of distribution or dividend, other than an issue of securities to holders of Units who have elected to receive distributions in securities of the Fund in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to all or substantially all holders of Units entitling them to acquire Units or other securities exchangeable into Units at less than 95% of the then Current Market Price of the Units; and (d) a distribution by the Fund to all or substantially all the holders of outstanding Units of (i) units of any class other than Units and other than units distributed to Unitholders who have elected to receive dividends or distributions in the form of such units in lieu of dividends or distributions paid in the ordinary course, (ii) rights, options, or warrants (excluding rights, options or warrants entitling the holders thereof for a period of not more than 45 days to subscribe for or purchase Units or securities exchangeable into Units), (iii) evidences of its indebtedness, or (iv) assets (excluding dividends or distributions paid in the ordinary course). There will be no adjustment of the Exchange Price in respect of any event described in (a), (b), (c) or (d) above if, subject to prior regulatory approval, Debentureholders are allowed to participate as though they had exchanged their Debentures prior to the applicable record date or effective date. Countryside Canada will not be required to make adjustments in the Exchange Price unless the cumulative effect of such adjustments would change the Exchange Price by at least 1%.

No fractional Units will be issued on any exchange but in lieu thereof Countryside Canada shall satisfy fractional interest by a cash payment equal to the current market price of such fractional interest.

Payment Upon Redemption or Maturity

On redemption or at Maturity, Countryside Canada will repay the indebtedness represented by the Debentures by paying to the Debenture Trustee in lawful money of the United States of America an amount equal to the principal amount of the outstanding Debentures, together with accrued and unpaid interest thereon, or at the option of Countryside Canada, upon at least 30 days' and not more than 60 days' prior notice, by delivery of a number of freely tradeable Units obtained by dividing the principal amount of the Debentures by 95% of the Current Market Price on the redemption date or at Maturity, as applicable.

Redemption and Purchase

The Debentures are not be redeemable on or prior to October 31, 2008. After October 31, 2008 and prior to October 31, 2010, the Debentures are redeemable in whole or in part at the option of Countryside Canada on not more than 60 days and not less than 30 days prior notice at a price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted average trading price of the Units on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the day prior to the date upon which the notice of redemption is given is at least 125% of the Exchange Price. On or after October 31, 2010, the Debentures are be redeemable prior to Maturity in whole or in part at the option of Countryside Canada on not more than 60 days and not less than 30 days prior notice at a price equal to the principal amount thereof plus accrued and unpaid interest.

Subject to regulatory approval, Countryside Canada may, at its option, elect to satisfy its obligation to pay the principal amount of the Debentures on redemption or at maturity through, in whole or in part, the delivery of freely-tradeable Units. The Fund will take all actions and do all things necessary or desirable to enable and permit Countryside Canada, in accordance with applicable law, to perform its obligations to deliver the requisite number of Units to the extent holders exercise their exchange right.

Countryside Canada or any of its affiliates have the right to purchase Debentures in the market, by tender or by private contract, provided however, that if an event of default under the Indenture has occurred and is continuing, Countryside Canada or any of its affiliates will not have the right to purchase Debentures by private contract.

Canadian Withholding Tax

Any holder of Debentures who is not resident in Canada for the purposes of the Tax Act is subject to withholding tax in respect of any payment or deemed payment of interest thereon. Applicable amounts will be withheld from cash payments of interest or deemed interest by Countryside Canada and used to satisfy this withholding tax obligation. To the extent that any such payment or deemed payment of interest is satisfied by Countryside Canada delivering Units to the non-resident holder, for example, on an exchange of Debentures into Units, Countryside Canada will withhold from the holder a portion of the Units that would have been so delivered to the non-resident holder. These withheld Units will be sold on the TSX and the proceeds from this sale will be used to satisfy the withholding tax obligation. Countryside Canada is entitled to withhold that number of Units that, when sold on the TSX, will yield cash proceeds (net of applicable expenses) sufficient to satisfy the withholding tax obligation. Any net proceeds from this sale in excess of the withholding tax obligation will be remitted to the non-resident holder of Debentures.

Subordination

The payment of the principal of, and interest on, the Debentures rank senior to Subordinated Intercompany Debt and subordinate in right of payment, as set forth in the Indenture, to the prior payment in full of all Senior Secured Indebtedness of Countryside Canada. The Debentures are effectively subordinate to claims of trade creditors of direct or indirect subsidiaries of Countryside Canada. "Subordinated Intercompany Debt" means intercompany debt of Countryside Canada and its subsidiaries. "Senior Secured Indebtedness" of Countryside Canada is defined in the Indenture as all secured indebtedness, liabilities and obligations of Countryside Canada including the indebtedness under the Amended Credit Facility but excluding the Debentures, whether outstanding on the date of the Indenture or thereafter created, incurred, assumed or guaranteed in connection with the acquisition by Countryside Canada of any businesses, properties or other assets or for monies borrowed or raised by whatever means (including, without limitation, by means of commercial paper, banker's acceptances, letters of credit, debt instruments, bank debt and financial leases, and any other secured liability evidenced by bonds, debentures, notes or similar instruments) or in connection with the acquisition of any businesses, properties or other assets or for monies borrowed or raised by whatever means (including, without limitation, by means of commercial paper, banker's acceptances, letters of credit, debt instruments, bank debt and financial leases, and any other secured liability evidenced by bonds, debentures, notes or similar instruments) by others including, without limitation, any subsidiary (as defined in the *Securities Act* (Ontario)) of Countryside Canada, for payment of which Countryside Canada is responsible or liable, whether absolutely or contingently.

The Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to Countryside Canada, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of Countryside Canada, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of Countryside Canada, then those creditors entitled to Senior Secured Indebtedness will receive payment in full before the holders of Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Debentures or any unpaid interest accrued thereon. The Indenture also provides that Countryside Canada will not make any payments when an event of default has occurred under the Senior Secured Indebtedness and is continuing.

Priority over Unit Distributions

The Declaration of Trust provides that certain expenses and liabilities of the Fund must be deducted in calculating the amount to be distributed to Unitholders. Accordingly, the funds required to satisfy the interest payable on the Debentures, as well as the amount payable upon redemption or maturity of the Debentures or upon an Event of Default (as defined below), will be deducted and withheld from the amounts that would otherwise be payable as distributions to Unitholders.

Put Right Upon a Change of Control

Upon the occurrence of a change of control of the Fund involving the acquisition of voting control or direction over 66⅔% or more of the outstanding Units and securities exchangeable into or carrying the right to acquire Units by any person or group of persons acting jointly or in concert or in event the Fund is no longer the sole shareholder of Countryside Canada (a "Change of Control"), each holder of Debentures may require (the "Change of Control Put Right") Countryside Canada to purchase, on the date which is 30 days following the giving of notice of the Change of Control as set out below (the "Put Date"), the whole or any part of such holder's Debentures at a price equal to 101% of the principal amount thereof (the "Put Price") plus accrued and unpaid interest up to, but excluding, the Put Date.

If 90% or more in the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered for purchase on the Put Date, Countryside Canada will have the right to redeem all the remaining Debentures on such date at the Put Price, together with accrued and unpaid interest up to, but excluding, the Put Date. Notice of such redemption must be given to the Debenture Trustee prior to the Put Date and as soon as possible thereafter, by the Debenture Trustee to the holders of the Debentures not tendered for purchase. The principal on the Debenture will be payable in lawful money of the United States of America or, at the option of the Fund and subject to applicable regulatory approval, by delivery of Units to satisfy, in whole or in part, its obligation to repay the principal amount of the Debentures.

The Indenture contains notification provisions to the following effect:

(a) Countryside Canada will promptly give written notice to the Debenture Trustee of the occurrence of a Change of Control and the Debenture Trustee will thereafter give to the holders of Debentures a notice of the Change of Control, the repayment right of the holders of Debentures and the right of Countryside Canada to redeem untendered Debentures under certain circumstances; and

(b) a holder of Debentures, to exercise the right to require Countryside Canada to purchase its Debentures, must deliver to the Debenture Trustee, not less than five business days prior to the Put Date, written notice of the holder's exercise of such right, together with the Debentures with respect to which the right is being exercised, duly endorsed for transfer.

Modification

The rights of the holders of any series of Debentures may be modified in accordance with the terms of the Indenture. For that purpose, among others, the Indenture contains certain provisions that will make binding on all holders of Debentures resolutions passed at meetings of the holders of such Debentures by votes cast thereat by holders of not less than 662⁄3% of the principal amount of the Debentures and then outstanding present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 662⁄3% of the principal amount of Debentures and then outstanding. In certain cases, the modification will, instead or in addition, require assent by the holders of the required percentage of Debentures of each particularly affected series. Under the Indenture, the Debenture Trustee will have the right to make certain amendments to the Indenture in its discretion, without the consent of the holders of the Debentures.

Events of Default

The Indenture provide that an event of default in respect of the Debentures will occur if any one or more of the following described events has occurred and is continuing: (i) failure for 15 days to pay interest on the Debentures, when due; (ii) failure to pay principal or premium, if any, on the Debentures, whether at maturity, upon redemption, by declaration or otherwise; (iii) certain events of bankruptcy, insolvency or reorganization of Countryside Canada under bankruptcy or insolvency laws; or (iv) default in the observance or performance of any material covenant or condition of the Indenture and the continuance of such default for a period of 30 days after notice in writing has been given by the Debenture Trustee to Countryside Canada specifying the default and requiring Countryside Canada to rectify same. If an event of default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall, upon the request of holders of not less than 25% in principal amount of the Debentures and then outstanding, declare the principal of and interest on all outstanding Debentures to be immediately due and payable. In certain cases, the holders of a majority of the principal amount of the Debentures, may, on behalf of the holders of all Debentures, waive any event of default under the Indenture and/or cancel any such declaration upon such terms and conditions as such holders shall prescribe.

Offers for Debentures

The Indenture contains provisions to the effect that if an offer is made for the Debentures then outstanding which is a take-over bid for the Debentures within the meaning of the *Securities Act* (Ontario) and not less than 90% of the Debentures then outstanding (other than Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Debentures held by holders of Debentures who did not accept the offer on the terms offered by the offeror, provided that holders of Debentures will have the right to elect to be paid the fair value of their Debentures by providing notice to the offeror and following the other procedures set forth in the Indenture.

Limitations on Ownership

In order for the Fund to maintain its status as a "mutual fund trust" under the Tax Act, the Fund must not be established or maintained primarily for the benefit of non-residents of Canada within the meaning of the Tax Act. Accordingly, at no time may non-residents of Canada be the beneficial owners of more than 49% of the Units (on either a non-diluted or fully-diluted basis). In addition, in order for the Fund to be exempt from the registration requirements as an investment company under the United States Investment Company Act of 1940, as amended (the "1940 Act"), at no time may more than 100 U.S. persons (using the principles for counting set forth in Section 3(c)(1) of the 1940 Act) be the beneficial owners of the Units, nor may any U.S. person be the beneficial owner of more than 10% of the Units. Consequently, Countryside Canada may require declarations as to the jurisdictions in which beneficial owners of Debentures are resident. If Countryside Canada becomes aware that either of the foregoing limitations may be contravened, the directors of Countryside Canada will make a public announcement and will not accept a subscription for Debentures from or issue or register a transfer of Debentures to a person unless the person provides a declaration that the person is not a non-resident of Canada. If, notwithstanding the foregoing, Countryside Canada becomes aware that more than 49% of the Units are held by non-residents (on either a non-diluted or fully-diluted basis), that more than 100 U.S. persons are beneficial owners of Units (on either a non-diluted or fully-diluted basis), or that any U.S. person is the beneficial owner of more than 10% of the Units (on either a non-diluted or fully-diluted basis), Countryside Canada may send a notice to the non-resident or U.S. holders, as applicable, chosen in inverse order to the order of acquisition or registration or in any manner as Countryside Canada may consider equitable and practicable, requiring them to sell their Debentures or a portion of their Debentures within a specified period of not less than 60 days. If the Debentureholders receiving the notice have not sold the specified number of Debentures or provided Countryside Canada with satisfactory evidence that they are not non-residents within that period, Countryside Canada may, on behalf of those Debentureholders, sell those Debentures and, in the interim, will suspend the rights attached to those Debentures. Upon that sale, the affected holders will cease to be holders of the Debentures and their rights will be limited to receiving the net proceeds of the sale.

To avoid having the Fund become subject to the fiduciary and prohibited transaction provisions of ERISA and Section 4975 of the Code, no Debentures may be beneficially owned by any ERISA Plan and any transferee of beneficial ownership of Debentures (whether by initial purchase or subsequent transfer) will be deemed to represent to Countryside Canada that it is not an ERISA Plan. Any purported transfer (whether or not the result of a transaction entered into through the facilities of the Toronto Stock Exchange) that, if effective, would result in any ERISA Plan beneficially owning any Debentures will be void from the date of the purported transfer, and the ERISA Plan that pursuant thereto would purport to have beneficial ownership of the Debentures will not acquire any interest in the Debentures. In the event of such a purported transfer, such Debentures will be transferred to a trust created by Countryside Canada and sold. The ERISA Plan will not have any beneficial interest in the trust, and the ERISA Plan's sole right with respect to the Debentures that were the subject of the purported transfer to the ERISA Plan will be to receive the net proceeds of sale of such Debentures by the trust. Countryside Canada may require any person who attempts to acquire Debentures or who otherwise is purported to beneficially own Debentures to provide a written statement or affidavit to Countryside Canada stating such information as Countryside Canada may request in order to determine whether such person is an ERISA Plan or not.

Book-Entry, Delivery and Form

Debentures will be issued in the form of fully-registered global Debentures (the "Global Debentures") held by, or on behalf of, CDS or its successor (the "Depository"), as custodian for its participants.

All Debentures will be represented in the form of Global Debentures registered in the name of the Depository or its nominee. Purchasers of Debentures represented by Global

Debentures will not receive Debentures in definitive form. Rather, the Debentures will be represented only in "book-entry only" form (unless Countryside Canada, in its sole discretion, elects to prepare and deliver definitive Debentures in fully registered form). Interests in the Global Debentures will be represented through book-entry accounts of institutions (including the Underwriters) acting on behalf of holders of interests, as direct and indirect participants of the Depository (the "participants"). Each purchaser of a Debenture represented by a Global Debenture will receive a customer confirmation of purchase from the Underwriter or Underwriters from whom the Debenture is purchased in accordance with the practices and procedures of the selling Underwriter or Underwriters. The practices of the Underwriters may vary but generally, customer confirmations are issued promptly after execution of a customer order. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interest in Global Debentures.

If the Depository notifies Countryside Canada that it is unwilling or unable to continue as depository in connection with the Global Debentures, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be eligible to be a depository and Countryside Canada and the Debenture Trustee are unable to locate a qualified successor, or if Countryside Canada elects, in its sole discretion, to terminate the book-entry system, with the consent of the Debenture Trustee, beneficial owners of Debentures represented by Global Debentures at such time will receive Debentures in registered and definitive form (the "Definitive Debentures").

Transfer and Exchange of Debentures

Transfers of interests in Debentures represented by Global Debentures will be effected through records maintained by the Depository for such Global Debentures or its nominees (with respect to interests of participants) and on the records of participants (with respect to interests of persons other than participants). Unless Countryside Canada elects, in its sole discretion, to prepare and deliver Definitive Debentures, beneficial owners who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interest in Global Debentures, may do so only through participants in the Depository's book-entry system. The ability of a holder of an interest in a Debenture represented by a Global Debenture to pledge the Debenture or otherwise take action with respect to such owner's interest in a Debenture represented by a Global Debenture (other than through a participant) may be limited due to the lack of a physical certificate.

Registered holders of Definitive Debentures may transfer such Debentures upon payment of any applicable taxes, duties or other charges incidental thereto, if any, by executing and delivering a form of transfer together with the Debentures to the Debenture Trustee at its principal offices in Toronto, Ontario, or such other city or cities as may from time to time be designated by Countryside Canada, with the approval of the Debenture Trustee, whereupon new Debentures will be issued in authorized denominations in the same aggregate principal amount as the Debentures so transferred, registered in the names of the transferees. No transfer or exchange of a Debenture will be registered on the date of any selection by the Debenture Trustee of any Debentures to be redeemed or during the seven preceding business days. In addition, no transfer or exchange of any Debentures which have been selected or called for redemption will be registered.

During 2006, US $10,839 Debentures were exchanged into 1,186,731 trust units, resulting in the principal amount of Debentures outstanding at December 31, 2006 of US $44,161.

DESCRIPTION OF COUNTRYSIDE CANADA

Share Capital

The authorized share capital of Countryside Canada consists of an unlimited number of common shares. All of the common shares of Countryside Canada are owned by the Fund.

Holders of common shares of Countryside Canada are entitled to receive dividends as and when declared by the board of directors and are entitled to one vote per share on all matters to be voted on at all meetings of shareholders. Upon the voluntary or involuntary liquidation, dissolution or winding-up of Countryside Canada, the holders of common shares are entitled to share rateably in the remaining assets available for distribution, after payment of liabilities and subject to the prior rights of preferred shares (if any).

Distribution Policy

Countryside Canada will adopt a policy to distribute all of its available cash, subject to applicable law, by way of monthly dividends on its common shares or other distributions on its securities, after:

- satisfaction of its debt service obligations, if any, under credit facilities or other agreements with third parties;
- satisfaction of its interest and other expense obligations, including (i) interest accrued or payable on the Countryside Canada Notes issued under the Countryside Canada Note Indenture described under "— Notes issued by Countryside Canada", (ii) interest accrued or payable on the Debentures described under "Description of the Debentures" (iii) and any applicable taxes;
- making any principal payments in respect of the Countryside Canada Notes; and
- the deposit of any amounts deemed prudent by the directors of Countryside Canada to fund the Holdback Account.

Countryside Canada retains a portion of its free cash in the Holdback Account. The Holdback Account will be used for working capital, operating shortfalls or future distributions. The Holdback Account has been initially funded with $2.4 million.

Notes Issued by Countryside Canada

The following is a summary of the material attributes and characteristics of the Countryside Canada Notes which were issued by Countryside Canada under the Countryside Canada Note Indenture. This summary is qualified in its entirety by reference to the provisions of the Countryside Canada Note Indenture, available at www.sedar.com, which contains a complete statement of those attributes and characteristics.

The Countryside Canada Notes will mature 20 years after the closing of the Offering, subject to prepayment from time to time as considered advisable by the board of directors of Countryside Canada.

The Countryside Canada Notes bear interest at the rate of 10.95% per annum. Under the terms of the Countryside Canada Notes, interest is accrued and is to be paid monthly within 30 days following the end of each month. The interest and principal on the Countryside Canada Notes is payable in lawful money of Canada by wire transfer or bankers' draft. The Countryside Canada Notes are fully registered notes.

The Countryside Canada Note Indenture also contains restrictive covenants relating to, among other things, the incurring of indebtedness by Countryside Canada, dispositions by Countryside Canada of all or substantially all of its assets, and distributions on the equity of Countryside Canada.

Payment upon Maturity

On maturity, Countryside Canada will repay the indebtedness represented by the Countryside Canada Notes by paying to the note trustee, on behalf of the holders, in lawful money of Canada, an amount equal to the principal amount of the outstanding Countryside Canada Notes, together with accrued and unpaid interest. If the Fund is a holder of Countryside Canada Notes at the time of such repayment, these amounts, less expenses, will be distributed by the Fund to the Unitholders.

Ranking and Guarantee

The Countryside Canada Notes are unsecured debt obligations of Countryside Canada and are subordinate in right of payment to all existing and future senior indebtedness of Countryside Canada, if any, and secured debt and guarantees of Countryside Canada, if any, and *pari passu* with all other existing and future unsecured indebtedness and other liabilities of Countryside Canada.

Default

The Countryside Canada Note Indenture provides that any of the following will constitute an event of default:

- default in payment of the principal amount of the Countryside Canada Notes when due;
- default in the payment of interest on the Countryside Canada Notes when due, if such default continues for a period of 30 days;
- default by Countryside Canada, Countryside District Energy or Countryside London Cogeneration of payment on any indebtedness exceeding $10,000,000 or acceleration of any such indebtedness;
- certain events of winding-up, liquidation, bankruptcy, insolvency or receivership of Countryside Canada, Countryside District Energy or Countryside London Cogeneration;
- the taking of possession by an encumbrance of all or substantially all of the property of Countryside Canada, Countryside District Energy or Countryside London Cogeneration;
- Countryside Canada, Countryside District Energy or Countryside London Cogeneration ceasing to carry on the businesses carried on, or a substantial part thereof, in the ordinary course;
- default in the observance or performance of any other covenant or condition of the Countryside Canada Note Indenture and the continuance of that default for a period of 30 days after notice in writing has been given by the note trustee to Countryside Canada, which notice specifies the default and requires Countryside Canada to remedy the default; or
- Countryside Canada, Countryside Acquisition, Countryside District Energy or Countryside London Cogeneration, and their respective subsidiaries, incurring any indebtedness for borrowed money that would cause the debt to equity ratio of Countryside Canada, on a consolidated basis, to exceed a specified ratio if such default continues for a period of 30 days.

Amended Credit Facility

The Fund, through Countryside District Energy, has entered into an amended and restated credit agreement with a syndicate of Canadian chartered banks (collectively, the "Lenders") providing for a revolving term facility of up to $55 million used in part to assist in financing the acquisition of Ripon Power (the "Amended Credit Facility"). As of March 26th, 2007, the Amended Credit Facility was drawn in the amount of approximately $13.4 million. The principal amount drawn on the Amended Credit Facility is repayable June 27, 2008 unless repaid earlier in accordance with its terms or accelerated. The Lenders waiver of the cross-default arising from the USEB Bankruptcy expires on May 31, 2007 and thus the Amended Credit Facility may be accelerated on such date unless the waiver is extended or made permanent or the Amended Credit Facility is refinanced. Amounts drawn under the Amended Credit Facility are principally collateralized by (i) a general security agreements and securities pledge from Countryside District Energy, and a (iii) a guarantee and general security agreements by Countryside Canada, Countryside London Cogeneration and Countryside US Holding. In connection with the closing of the Second Offering, the Fund repaid a portion of the outstanding balance under the Amended Credit Facility and secured certain consents of the Lenders and otherwise amended the Amended Credit Facility to facilitate the completion of the Second Offering.

The Amended Credit Facility contains customary representations, warranties, covenants (including restrictions on incurring additional indebtedness), conditions to funding and events of default. The Amended Credit Facility is also subject to financial covenants regarding total debt to capitalization (not to exceed a ratio of 0.5:1 at any time) and debt to earnings before interest, taxes, depreciation and amortization (not to exceed a ratio of 3.5:1 at any time).

The Amended Credit Facility is guaranteed by entities from which the Fund receives its cash distributions and as a result, the amounts owing under the Amended Credit Facility and any interest thereon will be payable in priority to any cash distributions to Unitholders and payments to Debenturehoders.

DESCRIPTION OF COUNTRYSIDE HOLDING

Share Capital

The authorized share capital of Countryside Holding consists of 1,000 common shares. All of the common shares of Countryside Holding are owned by Countryside Canada. Holders of common shares of Countryside Holding are entitled to receive dividends as and when declared by the board of directors and are entitled to one vote per share on all matters to be voted on at all meetings of shareholders. Upon the voluntary or involuntary liquidation, dissolution or winding-up of Countryside Holding, the holders of common shares are entitled to share ratably in the remaining assets available for distribution.

Countryside Holding Note

The following is a summary of the material attributes and characteristics of the US$52,139,000 unsecured subordinated promissory note (the "Countryside Holding Note"), which was issued by Countryside Holding to Countryside Canada on the closing of the Offering. This summary is qualified in its entirety by reference to the provisions of the Countryside Holding Note, which contains a complete statement of those attributes and characteristics.

Interest and Maturity

The Countryside Holding Note matures on the tenth anniversary of the closing date of the Offering (the "Closing Date"), subject to Early Maturity or redemption as described below. Notwithstanding the foregoing, Countryside Canada may, at any time after the sixth anniversary of the Closing Date but on or before the seventh anniversary of the Closing Date, elect to require that Countryside Holding repay the principal amount of the Note, and any interest then outstanding on the seventh anniversary of the Closing Date ("Early Maturity").

The Countryside Holding Note bears interest at the rate of 7.5% per annum. Under the terms of the Countryside Holding Note, interest is accrued and is to be paid monthly within 15 days following the end of each month. The interest and principal on the Countryside Holding Note is payable in lawful money of the United States by wire transfer or bankers' draft.

The Countryside Holding Note also contains restrictive covenants relating to, among other things distributions by Countryside Holding or any of its subsidiaries, incurrence of liens and the incurrence of indebtedness by Countryside Holding or its subsidiaries.

Payment upon Maturity

On maturity, or Early Maturity, Countryside Holding is required to repay the indebtedness represented by the Countryside Holding Note by paying to Countryside Canada, in lawful money of the United States, an amount equal to the principal amount of the outstanding Countryside Holding Note, together with all accrued and unpaid interest thereon to the maturity date or the Early Maturity date.

Subordination and Guarantee

The Countryside Holding Note is a general unsecured obligation of Countryside Holding and is subordinate in right of payment to all existing and future senior indebtedness of Countryside Holding, and *pari passu* with all other existing and future unsecured indebtedness and other liabilities of Countryside Holding that is not subordinated indebtedness. Countryside Holding's subsidiaries (the "Guarantors") guarantee the obligations of Countryside Holding under the Countryside Holding Note pursuant to a separate guarantee agreement. These guarantees rank *pari passu* with all other senior unsecured indebtedness of the Guarantors, but are subordinated to their guarantees with respect to any senior secured indebtedness of Countryside Holding. The guarantees allow the holders of the Countryside Holding Note to look to Countryside Holding's subsidiaries in case of default under the Countryside Holding Note. However, should any of the principal, interest or similar payments under any senior secured indebtedness of Countryside Holding have either come due and not been paid or be in default, all obligations under any senior secured indebtedness of Countryside Holding shall first be paid in full, in cash, before any payment on account of the principal or interest due under the Countryside Holding Note is paid.

Redemption and Prepayment

Provided Countryside Holding has available cash, the distribution of which is considered advisable by its board of directors and is not restricted by the terms of any senior secured indebtedness of Countryside Holding, Countryside Holding may, to the extent of such available cash, and upon not less than 30 days' written notice to Countryside Canada, redeem all or any portion of the Countryside Holding Note without the consent of Countryside Canada, at specified redemption prices (expressed as percentages of principal amount), plus accrued and unpaid interest on the Countryside Holding Note to be prepaid to the date of redemption if redeemed during the 12-month period commencing on a specified date in each year.

Default

The Countryside Holding Note provides that certain events will result in an event of default, including:

- default in payment of the principal amount of the Countryside Holding Note when the same becomes due;

- the failure to pay the interest obligations of the Countryside Holding Note when the same becomes due, for a period of 30 days;

- acceleration of any indebtedness for borrowed money of Countryside Holding or any of the Guarantors with an outstanding principal amount exceeding $5,000,000;

- certain events of winding-up, liquidation, bankruptcy, insolvency or receivership of Countryside Holding, the Guarantors or any of their material subsidiaries;

- the taking of possession by any encumbrancer of all or substantially all of the property of Countryside Holding, any of the Guarantors or any of their material subsidiaries;

- Countryside Holding, a Guarantor or any of their material subsidiaries ceasing to carry on the business carried on, or a substantial part thereof, in the ordinary course;

- Countryside Holding declaring or making a distribution during the existence of a default or event of default;

- a judgment or order for payment in excess of $15,000,000 is rendered against Countryside Holding or any Guarantor and either enforcement proceedings have been commenced or there is a period of 30 days during which a stay of proceedings is not in effect;

- default in the observance or performance of any other covenant of the Countryside US Holding Note and the continuance of that default for a period of 60 days after notice in writing has been given to Countryside Holding, which notice specifies the default and requires Countryside Holding to remedy the default;

- the Countryside Holding Note or any guarantee therefore ceases to be in full force and effect, except as contemplated by the terms thereof, or Countryside Holding or any Guarantor denies or disaffirms its obligations under the Countryside Holding Note or any guarantee therefore, except as contemplated by the terms of the Countryside Holding Note;

- a default by Countryside Holding or the Guarantors under a contract material to the business of Countryside US and the Guarantors if such default would have a material adverse effect on the business of Countryside Holding and the Guarantors, taken as a whole, which default is not rectified by Countryside US Holding or the applicable Guarantor within the specified time period in relevant material contract; or

- a default under or termination or revocation of, any permit material to the business of Countryside Holding and the Guarantors if such default, revocation or termination would have a material adverse effect on the business of Countryside Holding and the Guarantors, taken as a whole.

United States Tax Considerations

Countryside Holding's business in the United States will be subject to tax on its taxable income at rates generally applicable to corporations in the United States. For U.S. federal income tax purposes, Countryside Holding will report on its U.S. federal income tax returns its share of the income from Ripon Power and Ripon. In computing its income for U.S. federal income tax purposes, Countryside Holding intends to claim interest deductions with respect to the Countryside Holding Note. See "Risk Factors – Risks Related to the Structure of the Fund - United States Tax-Related Risks".

Interest and dividends from U.S. sources, such as the contemplated payments of interest and dividends from Countryside Holding to Countryside Canada, are generally subject to withholding at a rate of 30%. However, under the current provisions of the income tax treaty between the United States and Canada, payments of interest and dividends by Countryside Holding to Countryside Canada will be subject to withholding at the reduced rates of 10% and 5%, respectively.

TRUSTEES, DIRECTORS AND MANAGEMENT

The Trustees of the Fund supervise the activities and manage the investments and affairs of the Fund. The Fund has three Trustees all of whom are "unrelated" as such term is defined in the Toronto Stock Exchange Company Manual. Each Trustee holds office until the next annual meeting or until his successor is elected or appointed.

The following table sets forth the names of, and certain information for, the Trustees of the Fund, the Directors of Countryside Canada and the officers of Countryside Ventures for the 2006 fiscal year:

Name & Municipality of Residence	Positions and Offices held with the Fund and its Subsidiaries	Principal Occupation	Date Appointed as a Trustee/ Director/ Officer	Ownership or Control Over Trust Units[1]
V. James Sardo [2], [3] Mississauga, Ontario Canada	Chairman and Trustee of the Fund and Director of Countryside Canada	Corporate Director and Trustee, including UE Waterheater Operating Trust, Hydrogenics Corporation, CDI Income Fund, and New Flyer Industries Inc., 2003 – present	February 16, 2004	5,000
James R. Anderson [2], [3] Mississauga, Ontario Canada	Trustee of the Fund and Director of Countryside Canada	Executive Vice President and Chief Financial Officer, Denison Mines Inc., 2004 – December 2006, Executive Vice President and Chief Financial Officer Denison Mines Corp., December 2006-present	February 16, 2004	6,100
Oskar Sigvaldason[2], [3] St. Catherine's, Ontario Canada	Trustee of the Fund and Director of Countryside Canada	Director and Past Chair of the Energy Council of Canada and Director, Toronto Board of Trade, 2003 – present. Fortis, Ontario 2005 - present, Electrical Safety Authority 2005 - present, Director Hatch Group 2006 - present	May 5, 2005	1,000[4]

Name & Municipality of Residence	Positions and Offices held with the Fund and its Subsidiaries	Principal Occupation	Date Appointed as a Trustee/ Director/ Officer	Ownership or Control Over Trust Units[1]
Göran Mörnhed Cortland, New York United States	Director of Countryside President and Chief Executive Officer of Countryside Ventures		February 17, 2004	16,520
Edward M. Campana Pelham Manor, New York United States	Executive Vice President and Chief Financial Officer of Countryside Ventures		April 8, 2004	11, 870
Allen J. Rothman Brooklyn, New York United States	Senior Vice President of Countryside Ventures		April 8, 2004	12,100

1) The information as to Units beneficially owned, directly or indirectly, including by associates or affiliates, not being within the knowledge of the Fund, has been furnished by the respective nominees individually. There is only one class of voting securities, which are Units of the Fund.
2) Member of the Joint Audit Committee.
3) Member of the Joint Compensation, Nominating and Corporate Governance Committee.

As at March 30, 2007 the total number and percentage of Trust Units owned by all Trustees, Directors and executive officers of the Fund and its subsidiaries as a group was 52,590 or 0.253%.

Conflicts of Interest

To ensure proper governance, all agreements and financial arrangements between or among the Fund or its subsidiaries, on the one hand, and USEY and USEB and/or their subsidiaries, on the other hand, and any decision to enforce or refrain from enforcing rights with respect to such agreements and arrangements, shall be approved by the Trustees on behalf of the Fund or its subsidiaries and no person who is simultaneously serving as an officer or director of the Fund or its subsidiaries and USEY and/or USEB or their subsidiaries or is otherwise conflicted shall vote on such matters. Similarly, all decisions involving the enforcement, waiver or modification or any provision in any such agreements or any other matters in which the interests of the Fund or its subsidiaries and, USEY and/or USEB or their subsidiaries are in conflict, will also be subject to such procedures. In this connection, the Fund and USEY each expect to acquire or pursue investments in energy projects and businesses in the future.

To ensure proper governance, the Manager shall not (i) enter into any material transaction on behalf of Countryside Canada or its subsidiaries with the Manager or an affiliate of the Manager or (ii) amend any terms of the Management Agreement without first obtaining the approval of the majority of the directors of Countryside Holding, (and if applicable, Countryside Canada) who are independent of the Manager and its subsidiaries. In addition, no officer, director or equity owner of the Manager who is simultaneously a director or officer of Countryside Canada or any of its subsidiaries, shall vote as a director of Countryside Canada or its subsidiaries on any matter relating to the Management Agreement or the Administration Agreement or the Manager's LTIP interest in any subsidiary of Countryside Canada. See "The Management and Administration Agreements – Management Agreement".

JOINT AUDIT COMMITTEE

Charter of the Joint Audit Committee

The Charter of the Amended and Restated Joint Audit Committee of the board of Trustees of the Fund and the board of Directors of Countryside Canada, as approved on March 9, 2006 is set out in Schedule A to this Annual Information Form.

Composition of the Joint Audit Committee

The Joint Audit Committee is comprised of all of the Trustees, including; V. James Sardo, James R. Anderson and Oskar Sigvaldason. Each member of the Joint Audit Committee is independent and financially literate as defined under Multilateral Instrument 52-110 – *Audit Committees.*

Relevant Education and Experience

In addition to each member's general business experience, the education and experience of each Joint Audit Committee Member that is relevant to their performance in that capacity is set forth below.

Member Name	Independent	Financially Literate	Education & experience relevant to performance of audit committee duties
James R. Anderson (Chair of Joint Audit Committee)	Yes	Yes	▪ Chartered Accountant (ICAO) ▪ Bachelor of Arts majoring in Economics from University of Windsor and Executive Management Program from University of Western

			Ontario • Held positions as Chief Financial Officer at Denison Mines, Chief Financial Officer of Rogers Cable, Chief Operating Officer and Chief Financial Officer at Union Gas, and practiced Public Accounting with Clarkson Gordon
V. James Sardo	Yes	Yes	• MBA • Former CEO of numerous public companies and their subsidiaries and has had CFOs reporting to him. • Serves on the Audit Committee of other public company boards.
Oskar T. Sigvaldason	Yes	Yes	• President and CEO of Acres International for nine years and had CFOs reporting to him. • Serves on the Audit Committee of other public company boards.

Pre-approval Policies and Procedures

On August 5, 2004, the Joint Audit Committee approved a resolution designating Mr. Anderson as the member of the Committee to whom all requests for pre-approvals of non-audit related services would be made. The pre-approval of non-audit services must be presented to the full Committee at its first scheduled meeting following such pre-approval.

PROMOTER

USEY took the initiative in organizing the business and affairs of the Fund and may be considered to have been a promoter of the Fund at the time of its initial public offering within the meaning of applicable securities legislation. To the Fund's knowledge, USEY does not beneficially own, directly or indirectly, or exercise control over, any securities of the Fund. USEY owns a 100% interest in USEB. USEB and certain of its subsidiaries are parties to the USEB Settlement and are obligated under the Allowed Secured Claim a. For a description of the Allowed Secured Claim see "the Renewable Energy Projects-USEB Bankruptcy" In connection with the closing of the initial public offering of the Fund, the Fund indirectly acquired all of the issued and outstanding shares of USE Canada Holdings (now Amalgamated into Countryside District Energy) from USEY for a purchase price of $17,635,090. The purchase price for the shares of USE Canada Holdings was determined based on the pricing of the Fund's initial public offering.

The promoter is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside Canada. Although the promoter has appointed

Countryside Canada, is 495 Richmond Street, Suite 920, London, Ontario, Canada, as its agent for service of process in Ontario, it may not be possible for investors to collect from the promoter judgments obtained in Canada predicated on the civil liability provisions of securities legislation of certain of the provinces and territories of Canada.

LEGAL PROCEEDINGS

USEB Bankruptcy

On November 29, 2006 USEB and various subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York.

At the urging of the Bankruptcy Court, the Fund, USEY and USEB, on the other hand, participated in a mediation on January 12 and 13, 2007 respecting the outstanding disputes between them.

Through the mediation, the Fund, USEY, USEB and the Fund's executives, in their individual capacity, reached agreement in principle on the USEB Settlement. The USEB Settlement is formalized in (i) a Settlement Agreement by and among USEY, USEB and certain of its affiliates (collectively the "US Energy Parties"), the Fund, Countryside Canada, Countryside US Power and Countryside Ventures LLC (collectively "Countryside"), Goran Mornhed. Edward Campana and Allen Rothman (the "Individuals" and together with Countryside the "Countryside Parties") and (ii) a Stipulation and Final Order (I) Authorizing Debtors To Use Certain Cash Collateral And (II) Granting Adequate Protection To Countryside Canada Power Inc. executed by USEB and its debtor affiliates, Countryside Canada and the Official Committee of Unsecured Creditors (the " Final Cash Collateral Order") . The Settlement Agreement and Final Cash Collateral Order were formally approved by order of the Bankruptcy Court on February 16, 2007 over the objection of the State of Illinois (the "Approval Order"). The Approval Order and the Final Cash Collateral Order became final and non-appealable on February 26, 2007 and the Settlement Agreement became effective on March 7, 2007. The Final Cash Collateral Order became effective immediately.

The following summary of certain terms of the USEB Settlement is subject to and qualified in its entirety by reference, to all the terms of the Settlement Agreement and the Final Cash Collateral Order.

The USEB Settlement settles Countryside Canada's claims for all amounts claimed under the USEB Loan (including, without limitation, principal, pre and post-petition interest, make-whole, expenses and indemnity) by allowance of a secured claim against USEB and its debtor affiliates of US$99,000,000 (or approximately $116,000,000 at the then current exchange rate) in the USEB Bankruptcy (the "Allowed Secured Claim"). The Allowed Secured Claim continues to be secured by a first lien on substantially all of the assets of USEB and its subsidiaries, which may be enforced through the enforcement remedies provided in the USEB Loan.

The settlement provides for installment cash payments on the Allowed Secured Claim of US$3,000,000 on or before January 31, 2007 (which was paid in cash on January 31, 2007), US$30,000,000 on or before March 31, 2007 (which was paid in cash over a period from March 9-13, 2007), and the remaining principal balance and accrued unpaid interest on or before maturity at May 31, 2007. USEB may pay up to US$2 million in USEY common stock which is registered or otherwise freely tradable with the number of shares to be calculated based on the weighted average closing price on the five trading days preceding the payment.

Outstanding principal amounts under the Allowed Secured Claim bear cash interest at a rate of 10% per annum from February 1, 2007, payable monthly in U.S. dollars. Upon any default in timely payment of principal or interest, the unpaid balance of the Allowed Secured Claim shall bear 12% default interest from the date of the last payment until such default has been cured or waived.

The USEB Allowed Claim may be prepaid at any time prior to May 31, 2007 without penalty. The USEB Allowed Claim must be paid from the proceeds of any DIP financing provided that no DIP financing shall prime or be parri-passu with the liens securing the Allowed Secured Claim.

The USEY Parties on the one hand and the Countryside Parties on the other hand exchanged general releases covering all claims (as defined in the Settlement Agreement) arising before the Effective Date of the Settlement Agreement with certain exceptions including claims arising from the Allowed Senior Claim, the Settlement Agreement, the Final Cash Collateral. Among other things, in such releases the USEY Parties released all claims against the Countryside Parties alleging any improprieties respecting the USEB Loan, the Countryside Parties released USEB from all claims relating to the USEB Royalty and all the Parties released each other from all claims relating to the Development Agreement.

Development Agreement Litigation

In consideration for development services to be performed under the Development Agreement, Countryside U.S. was to receives an annual fee of US$430,000 from an indirect subsidiary of Cinergy (now Duke Energy) and USEY. USEY ceased making monthly payments under the Development Agreement in May 2005. After unsuccessful efforts to negotiate a resolution, in July 2006, Countryside U.S. Power commenced an action against USEY in New York State Supreme Court, New York County styled Countryside U.S. Power Inc. v. U.S. Energy Systems, Inc. for breach of contract seeking all amounts due from USEY over the remaining of the Development Agreement. USEY filed an answer denying the allegations in the complaint and alleging counterclaims seeking, among other things, to void the Development Agreement. In December 2006, Countryside U.S. removed the state court litigation to the United States District Court for the Southern District of New York which thereafter transferred the case to the United States Bankruptcy Court for the Southern District of New York where it became a related adversary proceeding in the USEB Bankruptcy styled Countryside U.S. Power, Inc. v. U.S. Energy Systems, Inc. Adv. No. 06-15350 (RDD). As part of the USEB Settlement which became effective on March 7, 2006 Countryside U.S. Power, Inc and USEY released all claims they had against each other relating to the Development Agreement and obtained an order dismissing the Development Agreement litigation with prejudice. Accordingly neither party has any rights or obligations respecting each other under the Development Agreement.

In November 2004, a foreclosure action encaptioned CIB Bank v. Miss Mimi Corporation et al in the Circuit Court, Lake County, Illinois was commenced by CIB Bank, the holder of mortgages on the real property on which the project owned by Countryside Genco LLC ("Countryside Genco"), an indirect subsidiary of USEB, is located. Countryside Canada was named as a defendant in the action due to its security interest, under the USEB Loans, in Countryside Genco's interest in the site lease and related easement. This action was settled in 2006 with no adverse impact on the Fund, USEB or their subsidiaries..

In December 2005, two shareholders of USEY commenced an action in the Delaware Court of Chancery against USEY, the current directors of USEY, certain former directors and officers of USEY (including Mssrs. Mornhed, Campana and Rothman), the Fund and Countryside U.S. Power alleging, among other things, that the defendants violated the Delaware General Corporations Law and fiduciary duties to USEY shareholders in connection with USEY's sale of indirect ownership of the District Energy Systems to the Fund and the consummation of the April 2004 USEB Loan transaction. The Plaintiffs sought damages and equitable relief. This action was settled in June 2006 with no adverse impact on the Fund or its subsidiaries.

A proceeding is currently pending before the CPUC in Docket No. R 99-11-022 in which the CPUC is considering whether to apply retroactively for the period December, 2000 through March, 2001 a March, 2001 decision (D. 01-03-067) which, among other things, modified the methodology used in calculating SRAC and thereby decreased SRAC levels for the period commencing March 27, 2001. In February, 2005, a Draft Decision was issued by the assigned Commissioner who found that "evidence shows SRAC prices were correct between December 2000 and March 2001, and retroactive application of the modified SRAC formula is not warranted." Various parties have submitted comments on the Draft Decision, including PG&E, SCE, a ratepayer organization and the CPUC's Office of Ratepayer Advocates, objecting to the Draft Decision. The CPUC has not yet issued a final decision in the matter and is free to accept the Draft Decision as written, modify it or reject it in its entirety. The outcome of this proceeding cannot be predicted. Even in the event of an adverse CPUC decision, the Manager has been advised by counsel that Ripon would have several meritorious legal defenses that would be available to protect Ripon from any material adverse impact. However, there is no assurance that Ripon would prevail on such defenses if called upon to assert them. If the CPUC ultimately adopts a final order imposing a retroactive modification to the SRAC formula, and a remedy based thereon is ordered or authorized, and if such final order and remedy is not reversed on appeal, California QFs including the Ripon and San Gabriel Facilities could be required to make refunds and/or accept reduced payments (by way of offset of past overpayment against future payments for power delivered) under their respective PPAs. Such refunds or reduced payments could be material for Ripon or San Gabriel, and could materially affect their ability to generate distributable cash.

There is an open proceeding in which the CPUC has indicated it will review the Transition Formula for SRAC pricing for possible prospective changes. There can be no assurance that any change in the SRAC price methodology will not adversely affect the operating margins derived from the Ripon PPA and San Gabriel PPA in a material manner. Any adverse change in energy margins may negatively impact Ripon's cash flow which in turn could reduce distributable cash. Such impact may be material.

From to time Ripon Cogeneration has received notices of violation ("NOV's") from the San Joaquin District respecting alleged violations of applicable environmental laws and permits. None of the NOV's involve excessive emissions or hazardous wastes in any material respect. Ripon Cogeneration has settled certain of these NOV's for immaterial sums and intends to contest or resolve the remaining pending NOVS. The Manager does not expect such NOV's to have a material adverse effect on the Fund.

Other than as described above, none of the Fund or to the knowledge of the Manager, USEB or their respective subsidiaries is involved in any legal proceedings which the Manager believes would have a material effect on the Fund, Countryside Canada, Countryside Holding, Countryside District Energy Holdings or USEB on a consolidated basis To the knowledge of the Manager, other than potential claims by the State of Illinois, no legal proceedings of a material nature involving the Fund or USEB or their respective subsidiaries are contemplated by any individuals, entities or governmental authorities.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

During 2005, the Fund entered into the Management Arrangement as described under "The Management and Administration Agreements". Such Management Agreement was amended in 2007 as described under "The Management and Administration Agreements – Management Agreement". Pursuant to the Management Agreement, the Manager received an LTIP interest in connection with the acquisition of Ripon Power and the development of Countryside London Cogeneration.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Ernst & Young LLP, Chartered Accountants, Ernst & Young Tower, 222 Bay Street, Toronto-Dominion Centre, Toronto are the auditors of the Fund.

For the period ended December 31, 2006, Ernst & Young LLP fees amounted to approximately $421,678, as detailed below, for services to the Fund and its direct and indirect subsidiaries:

Ernst & Young LLP

2006 Fees

Audit fees	$ 322,500
Audit-related fees	59,178
Non-audit fees[3]	40,000
Total	$421,678

2005 Fees

Audit fees[1]	$ 835,000
Audit-related fees[2]	335,396
Non-audit fees[3]	192,932
Total	$1,363,328

[1] Audit fees were primarily comprised of services provided with respect to services performed for the short form Prospectus issued in November of 2005, and for review engagements performed for the quarterly reports in Q1, Q2, and Q3 of 2005 as well as 2005 audit work.

[2] Audit-related fees pertain to accounting advice and consulting as well as audit fees for Ripon Power LLC for the year ended December 31, 2004.

[3] Non-audit fees relate to tax work performed throughout the year.

The transfer agent and registrar for the Units is CIBC Mellon Trust Company at its principal office in Toronto, Ontario.

All of the Units are registered in the name of The Canadian Depository for Securities Limited ("CDS"), which holds such Units on behalf of the Beneficial Unitholders.

MATERIAL CONTRACTS

The following are the only material contracts, other than contracts entered into in the ordinary course of business, which have been entered into by the Fund, Countryside Canada and Countryside Holding within the most recently completed financial year, or before the most recently completed financial year but are still in effect:

- the Declaration of Trust described under the heading "Description of the Fund";
- the Acquisition Agreement relating to the acquisition of USE Canada Holdings by USEY referred to under the heading "General Development of the Business — Significant Acquisitions";
- the Countryside Canada Note Indenture referred to under the heading "Countryside Canada-Notes issued by Countryside Canada.";
- the Indenture referred to under "Description of the Debentures";

- the Underwriting Agreement entered into by the Fund, USEY and the underwriters of the Fund's initial public offering dated March 25, 2004;

- the Underwriting Agreement entered into by the Fund and the underwriters of the Fund's second public offering dated October 27, 2005;

- the USEB Loan Agreement referred to under the heading "The Renewable Energy Projects — USEB Loans";

- the agreement creating the USEB Royalty Interest referred to under the heading "The Renewable Energy Projects — USEB Royalty Interest";

- the Second Amended and Restated Credit Facility referred to "Description of Countryside Canada – Amended Credit Facility";

- the Stock Purchase and Sale Agreement relating to the acquisition of Lightyear Rockland Partners LLC referred to in the 2005 Prospectus under "The Acquisition";

- the Management Agreement referred to under "The Management and Administration Agreements";

- the Administration Agreement referred to under "The Management and Administration Agreements";

- the Development Agreement referred to under the heading "The Development and Improvement Agreements — Development Agreement with USEY and Cinergy"; and

- the Improvement Agreement referred to under the heading "The Development and Improvement Agreements — Improvement Agreement with USEB".

- Amendment No. 1 to the Management Agreement referred to under the heading "The Management and Administration Agreements – Management Agreement".

- the USEB Settlement Agreement as referred to under the heading "The Renewable Energy Projects – USEB Bankruptcy" referred to under the heading

INTERESTS OF EXPERTS

Ernst & Young LLP, the auditor of the Fund, has been named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 – Continuous Disclosure Obligations by the Fund during, or relating to, the Fund's financial years ended December 31, 2006 and December 31, 2005. To the knowledge of the Fund, Ernst & Young LLP holds no registered or beneficial interest, directly or indirectly, in any securities or other property of the Fund or any of its associates or affiliates.

ADDITIONAL INFORMATION

Additional information will be contained in the Fund's Management Information Circular which shall be filed in April 2006 for the Annual and General Meeting of Unitholders to be held on May 9, 2006.

Additional financial information is provided in the Fund's financial statements and MD&A for the period ended December 31, 2006. Additional information relating to the Fund may be found on SEDAR at www.sedar.com.

GLOSSARY OF TERMS

"**Acquisition**" means the indirect acquisition by the Fund of the membership interests of Lightyear Rockland Partners LLC (the predecessor to Ripon Power), whose principal asset is Ripon pursuant to the Purchase and Sale Agreement.

"**Additional Advances**" means the funding of additional advances made by Countryside Canada to USEB in connection with the acquisition and amendment of the Existing Loans on closing of the Offering.

"2005 Prospectus" means the Fund's short form prospectus for its second public offering, dated November 8, 2005.

"**Administration Agreement**" means the management and administration agreement to be entered into on or prior to the closing of the Offering between the Fund, Countryside Canada and the Administrator.

"**Administrator"** means Countryside Canada Ventures Inc., a wholly-owned subsidiary of the Manager.

"**Affiliate**" means an affiliate within the meaning of the *Securities Act* (Ontario).

"**AJG**" means AJG Financial Services, Inc.

"**AJG Note**" means the non-recourse note in a principal amount of US$14 million issued by AJG to USEB on closing of the Offering.

"**Allowed Secured Claim"** means the senior secured claim in the amount of approximately US $66 in the pending Chapter 11 bankruptcy proceeding of USEB and its subsidiaries in the United States Bankruptcy Court for the Southern district of New York.

"Amended Credit Facility" means the amended revolving term facility of up to $80 million provided by a Canadian chartered bank to the Fund through Countryside Acquisition for the purpose of financing the Acquisition.

"**Avoided Cost**" means the incremental expense that a utility would incur to either generate or purchase, from an outside source, electricity, capacity or both.

"**Biogas**" means the methane gas, carbon dioxide and other gases that are emitted through the decomposition of waste material.

"**Book-Entry Only System**" means the book-based system administered by CDS.

"**Btu**" means British thermal unit.

"**Business**" means collectively, the District Energy Systems, the California Cogen Facilities, and the Renewable Energy Projects.

"**Business day**" means any day that is not a Saturday, Sunday or civic or statutory holiday in the Province of Ontario.

"**California Cogen Facilities**" means two gas-fired cogeneration facilities located in California.

"**Capital Event**" means a liquidation of USEB or a sale of substantially all of the assets of USEB.

"**CDS**" means The Canadian Depository for Securities Limited.

"CDS Participant" means a participant in the CDS depository service.

"CEC" means California Energy Commission.

"CHP" means combined heat and power.

"CHP Contract" means the contract entered into on October 16, 2006 between Countryside London Cogen and the OPA respecting the development, operation and sale of electricity from the London Cogen Facility.

"**Cinergy**" means Cinergy Corp.

"**Cinergy Solutions**" means Cinergy Solutions Inc.

"**Code**" means the *United States Internal Revenue Code of 1986*, as amended.

"Cogen Facilities" means the Ripon Facility and the San Gabriel Facility.

"**Countryside Acquisition**" means Countryside Canada Acquisition Inc., a corporation incorporated under the federal laws of Canada which was amalgamated with Countryside District Energy on January 1, 2007.

"**Countryside Canada**" means Countryside Canada Power Inc., a corporation incorporated under the federal laws of Canada and a wholly-owned subsidiary of the Fund.

"**Countryside Canada Note Indenture**" means the note indenture entered into between Countryside Canada and CIBC Mellon Trust Company, as trustee thereunder, pursuant to which Countryside Canada issued the Countryside Canada Notes, as the same may be amended, supplemented or restated from time to time.

"**Countryside Canada Notes**" means the 10.95% unsecured, subordinated notes issued by Countryside Canada to the Fund pursuant to the Countryside Canada Note Indenture.

"**Countryside District Energy**" means Countryside District Energy Corp. a corporation incorporated under the laws of Ontario and subsidiary of Countryside Canada.

"**Countryside Holding**" means Countryside US Holding Corp., a corporation incorporated under the laws of Delaware and a subsidiary of Countryside Canada.

"**Countryside Holding Note**" means the US$52,139,000 aggregate principal amount 7.5% unsecured, subordinated promissory note issued by Countryside Holding to Countryside Canada in connection with the Offering.

"**Countryside London Cogeneration**" means Countryside London Cogeneration Corp. a corporation incorporated under the laws of Ontario and a subsidiary of Countryside Canada.

"**Countryside U.S. Power**" means Countryside U.S. Power Inc., a corporation incorporated under the laws of Delaware and subsidiary of Countryside Holding.

"**CPUC**" means the California Public Utilities Commission.

"**CRA**" means the Canada Revenue Agency.

"**DBRS**" means Dominion Bond Rating Service Limited.

"**Debenture Trustee**" means the trustee or its successor as trustee under the Indenture.

"**Debentureholders**" means the holders of Debentures, and "**Debentureholder**" means any one of them.

"**Debentures**" means the 6.25% exchangeable unsecured subordinated debentures of Countryside Canada issued pursuant to the Indenture as of the date of closing of the Second Offering, and "**Debenture**" means one of them.

"**Declaration of Trust**" means the declaration of trust of the Fund dated February 16, 2004, as amended, supplemented or restated from time to time.

"**Development Agreement**" means the agreement which was entered into between Countryside U.S. Power USEY and an indirect subsidiary of Duke Energy regarding the future acquisition, development and improvement of energy projects.

"**Disqualified Recipient**" means (i) any person that owns, directly or indirectly (through ownership of USEY, Cinergy, or otherwise) and after application of the constructive ownership rules of Code section 871(h)(3), 10% or more of the total combined voting power of all classes of equity of USEB entitled to vote, (ii) a controlled foreign corporation related to USEB within the meaning of Code section 881(c)(3)(C), or (iii) a bank described in Code section 881(c)(3)(A) with respect to the USEB Loans.

"**Distributable Cash**" means, in general, all amounts of cash received by the Fund, for and in respect of a particular distribution period, including all cash amounts transferred from the Holdback Account, less all expenses and liabilities of the Fund which may reasonably be considered to have accrued and become owing in respect of that distribution period or a prior distribution period (if not accrued in such prior period), amounts that may be paid by the Fund in connection with any cash redemptions or repurchases of Units made during the distribution period, amounts that relate to repayment of any indebtedness of the Fund made during that distribution period, amounts which the Trustees may reasonably consider necessary to provide for payment of any liabilities which have been or will be incurred by the Fund, and any amounts for reasonable reserves in connection with pursuing any objective or activity of the Fund.

"**District Energy Systems**" means, collectively, the PEI District Energy System and the London District Energy System.

"**EPA**" means the United States Environmental Protection Agency.

"EPA 2005" means the *United States Energy Policy Act of 2005.*

"EPC Contract" means "design, procure, and construct" contract between Meccon and Countryside London Cogeneration to design, procure and construct and deliver a fully operational 19MW Cogeneration Plant in conformance with approved plans, manufacturers' specifications and the CHP Contract.

"**ERISA**" means the *United States Employee Retirement Income Security Act of 1974*, as amended.

"**ERISA Plan**" shall mean any employee benefit plan that is subject to the fiduciary and prohibited transaction provisions of ERISA and/or any plan that is subject to Section 4975 of the Code, any trust holding assets of such a plan, and any entity that is deemed to hold the assets of such a plan pursuant to 29 C.F.R. Section 2510.3-101, issued by the United States Department of Labor.

"ESA" means Energy Services agreement between Countryside London Cogeneration and Countryside District Energy under which Countryside London Cogeneration will sell steam generated by the London Cogen Facility to Countryside District Energy for use in the London District Energy System.

"Exchange Price" means the price of $10.75 per Unit, being a ratio of 109.4884 Units per US$1,000 principal amount of Debentures, subject to adjustment in certain events in accordance with the Indenture, at which price each Debenture will be exchangeable for Units at the option of the holder at any time prior to the close of business on the earlier of the Maturity Date and the business day immediately preceding the date specified by Countryside for redemption of the Debentures.

"**Excluded Assets**" means the equity and assets and liabilities of Brown County Energy Associates LLC, Garland Energy Development LLC, Hoffman Road Associates LLC, Oyster Bay Energy Partners LP, Zapco Development Corp., Zapco Equipment Corp., and ZFC Equipment Corp.

"**Existing Loans**" means the existing loans to USEB that were acquired by Countryside Canada and amended to reflect the Additional Advances and otherwise have the terms described herein.

"**FERC**" means the United States Federal Energy Regulatory Commission, an independent regulatory agency within the United States Department of Energy that, among other things, oversees regulatory matters relating to electricity projects.

"**FPA**" means the *United States Federal Power Act*, as amended.

"**Fund**" means Countryside Power Income Fund, an unincorporated, open-ended, limited purpose trust formed under the laws of the Province of Ontario.

"Fund's AIF" means the annual information form of the Fund dated March 31, 2005.

"**GAAP**" means generally accepted accounting principles.

"**Gasco**" means the legal entity that typically owns the biogas extraction rights and collection systems and collects and sells biogas to a Genco or a Transco, as the case may be.

"**GE/Jenbacher**" means GE/Jenbacher Energy Systems Ltd., a subsidiary of General Electric Company.

"**Genco**" means the legal entity that typically owns the power generating equipment and purchases biogas from a Gasco and sells the electricity it generates to an electric utility or industrial user.

"**Gigawatt hour**" or "**GWh**" means an amount of energy equivalent to one gigawatt of energy delivered continuously for one hour.

"**Gigawatts**" or "**GW**" means one million kilowatts of energy.

"**Green power**" or "**green energy**" means electricity generated from alternative or renewable resources, such as wind, solar, biomass or biogas.

"**Green Power Market**" means the market for green power that exists in those U.S. states and Canadian provinces that have implemented Renewable Portfolio Standards or have restructured their industry laws and/or regulations to create competitive wholesale and/or retail electricity markets.

"**Gross Contract Rate**" means the rate required to be paid by electric utilities in the State of Illinois under the Rate Incentive Program for electricity generated by a QSWEF and is equal to the average amount per kWh paid by the local government entities for electricity (with certain exceptions) in such QSWEF's jurisdiction.

"HOEP" means the Hourly Ontario Electricity Price.

"**Holdback Account**" means the account to be established by Countryside Canada on closing of the Offering (initially to be funded with $2.4 million) to stabilize cash distributions, as required.

"**ICC**" means the Illinois Commerce Commission.

"**Improvement Agreement**" means the agreement entered into between USEB and a subsidiary of the Fund providing the Fund with a right of first offer to acquire or invest in two expansion opportunities relating to the existing Countryside and Morris projects and two Greenfield development projects.

"Indenture" means the trust indenture dated as of the closing of the Offering between the Fund, Countryside Canada and the Debenture Trustee, governing the terms of the Debentures.

"**Initial Offering**" means the initial public offering of Units on March 29, 2004.

"IPO Closing" means the closing of the Fund's initial public offering of Units on April 8, 2004.

"**IRS**" means the United States Internal Revenue Service.

"Issuer" means collectively the Fund and Countryside Canada.

"**Kilowatt hour**" or "**kWh**" means an amount of energy equivalent to one kilowatt of energy delivered continuously for one hour.

"**Kilowatts**" or "**kW**" means 1,000 watts of energy.

"**London District Energy System**" means the district energy system owned by Countryside District Energy and located in London, Ontario.

"London Cogen Facility" means a gas-fired Cogeneration Facility being developed adjacent to the London District Energy System.

"Management Agreement" means the management agreement entered into between the Manager, Countryside Holding and Countryside Canada on September 23, 2005, as it may be amended, supplemented and restated from time to time.

"**Management and Administration Agreement"** means the management and administration agreement to be entered into on or prior to the closing of the Offering between the Fund, Countryside Canada and Countryside Canada Ventures Inc., a wholly-owned subsidiary of the Manager.

"Manager" means Countryside Ventures LLC.

"Manager's Ripon Subordinated Interest" means 25% of the subordinate membership interests of Ripon Power

"Maturity Date" means October 31, 2012, the maturity date of the Debentures.

"Meecon" means Meecon London Inc.

"**Megawatts**" or "**MW**" means 1,000 kilowatts of energy.

"**Megawatt hour**" or "**MWh**" means an amount of energy equivalent to one megawatt of energy delivered continuously for one hour.

"**MMBtu**" means one million Btu.

"**Municipal solid waste**" means waste sourced from local municipalities from which compostable and recyclable waste has been removed.

"NAES" or the "Operator" means North American Energy Systems, the operator of the California Cogeneration Facilities under contract.

"**New Credit Facility**" means the credit facility provided by Canadian financial institutions to Countryside Acquisition on closing of the Initial Offering in an aggregate amount of $35 million.

"OPA" means the Ontario Power Authority.

"**PEI**" means the Province of Prince Edward Island, Canada.

"**PEI District Energy System**" means the district energy system owned by Countryside District Energy and located in Charlottetown, PEI.

"Person" means any individual, sole proprietorship, partnership, firm, entity, unincorporated association, unincorporated syndicate, unincorporated organization, trust, body corporate, governmental authority, and where the context requires, any of the foregoing when they are acting as trustee, executor, administrator or other legal representative.

"**Plans**" means registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans, each as defined in the Tax Act.

"**PPA**" means power purchase agreement.

"**PUHCA**" means *Public Utility Holding Company Act of 1935*, as amended.

"Purchase and Sale Agreement" means the agreement dated June 29, 2005 pursuant to which Countryside Holding acquired all of the membership interests of Ripon Power for total consideration of approximately US$95.3 million.

"**PURPA**" means the *Public Utility Regulatory Policies Act of 1978*, as amended.

"**QF**" or "**Qualifying Facility**" means a qualifying facility under the FPA, as amended by PURPA.

"**QSWEF**" means a qualified solid waste energy facility under the *Illinois Local Solid Waste Disposal Act* and the *Illinois Public Utilities Act* that uses biogas produced from landfill sites as its primary fuel and qualifies as a QF.

"**Rate Incentive Program**" means the program that is part of the system established by the State of Illinois pursuant to the *Illinois Public Utilities Act* to govern the sale of electricity by QSWEFs, as more fully described under "U.S. Energy Biogas Corporation — Pricing Structure".

"Renewable Energy Projects" means the 23 renewable energy projects described under "The Renewable Energy Projects — Summary of the Renewable Energy Projects".

"**Renewable Portfolio Standards**" means renewable energy purchase requirements mandated by U.S. state law or Canadian provincial law for electric utilities.

"**RGS**" means Resource Generation Systems, Inc., a wholly-owned subsidiary of USEB.

"Ripon Cogeneration" means Ripon Cogeneration, LLC, a limited liability company formed pursuant to the laws of the State of Delaware and a subsidiary of Ripon Power.

"Ripon Facility" means the Ripon Cogeneration plant located in Pamona near San Francisco, California and owned by Ripon Cogeneration.

Ripon Gas Contract" means a fuel purchase agreement entered into with Sempra Energy Trading Corporation which terminates on March 31, 2008.

"Ripon Loan" means the project loan extended by the Union Bank of California and the Allied Irish Bank to Ripon Cogeneration that was acquired by Countryside Holding.

"Ripon Power" means Ripon Power LLC, a limited liability company formed pursuant to the laws of the State of Delaware and a subsidiary of Countryside Holding.

"Ripon PPA" means the power purchase agreement between the Ripon Facility and Pacific Gas and Electric Company, the principal operating subsidiary of PG&E Corporation, expiring in 2018.

"**Royalties**" means the payments made with respect to the USEB Royalty Interest prior to conversion.

"San Gabriel Facility" means the San Gabriel Cogeneration plant located near Los Angeles, California and owned by Ripon Cogeneration.

"San Gabriel PPA" means the power purchase agreement, as amended, between Simpson Paper Company and SCE and assigned to Ripon Cogeneration Inc. expiring in 2016.

"**S&P**" means Standard and Poor's, a division of The McGraw-Hill Companies, Inc.

"**Section 29**" means Section 29 of the *Internal Revenue Code* which addresses the sale of alternative fuels for the generation of energy.

"Second Offering" means the public offering by the Fund and Countryside Canada on November 14, 2005 pursuant to 2005 Prospectus.

"Securities" means, collectively, the Units and Debentures offered pursuant to this short form prospectus.

"Senior Secured Indebtedness" means in relation to Countryside Canada all secured indebtedness, liabilities and obligations of Countryside Canada, including the indebtedness under the Amended Credit Facility but excluding the Debentures, whether outstanding on the date of the Indenture or thereafter created, incurred, assumed or guaranteed in connection with the acquisition by Countryside Canada of any businesses, properties or other assets or for monies borrowed or raised by whatever means (including, without limitation, by means of commercial paper, banker's acceptances, letters of credit, debt instruments, bank debt and financial leases, and any liability evidenced by bonds, debentures, notes or similar instruments) or in connection with the acquisition of any businesses, properties or other assets or for monies borrowed or raised by whatever means (including, without limitation, by means of commercial paper, banker's acceptances, letters of credit, debt instruments, bank debt and financial leases, and any liability evidenced by bonds, debentures, notes or similar instruments) by others including, without limitation, any subsidiary (as defined in the *Securities Act* (Ontario)) of Countryside Canada, for payment of which Countryside Canada is responsible or liable, whether absolutely or contingently.

"SRAC" means the short-run avoidance cost formula adopted by the CPUC.

"Subordinated Intercompany Debt" means intercompany debt of the Fund and its subsidiaries.

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5^{th} Supp), as amended, including the regulations promulgated thereunder.

Tax Fairness Plan" means Department of Finance (Canada) October 31, 2006 draft changes to income tax rules applicable to certain publicly listed trusts and partnerships.

"**Transco**" means the legal entity that forms the part of the Renewable Energy Projects that purchases biogas from a Gasco to transport and sell to a third party as boiler fuel.

"**Treasury Regulations**" means the United States Treasury regulations (including final, temporary and proposed regulations) promulgated under the Code.

"**Treaty**" means the Convention between the United States of America and Canada with Respect to Taxes on Income and on Capital, as amended.

"**Trustees**" means the trustees of the Fund.

"TSX" means the Toronto Stock Exchange.

"Underwriters" means, collectively, CIBC World Markets Inc., RBC Dominion Securities Inc., TD Securities Inc., BMO Nesbitt Burns Inc. and National Bank Financial Inc., the underwriters of the Offering.

"Underwriting Agreement" means the agreement dated October 27, 2005 between the Issuer and the Underwriters, among others, in respect of the Offering.

"**Unitholders**" means the holders from time to time of Units and included, while the Units are registered in the Book-Entry Only System, the beneficial owners of Units.

"**Units**" means trust units of the Fund, each unit representing an equal undivided beneficial interest therein.

"**USEB**" means U.S. Energy Biogas Corp.

"**USEB Entities**" means the various corporations, limited liability companies and partnerships that directly own the Renewable Energy Projects.

"**USEB Loan Agreement**" means the amendment to the note purchase agreement entered into by Countryside Canada and USEB with respect to the USEB Loans.

"**USEB Loans**" means the Existing Loans acquired by Countryside Canada on closing of the Initial Offering, as amended to reflect the Additional Advances and otherwise have the terms described in the USEB Loan Agreement.

"**USEB Reserve**" means the debt service reserve established by USEB pursuant to the terms of the USEB Loan Agreement, which, on closing of the Offering, was funded with US$2 million.

"**USEB Royalty Interest**" means the convertible royalty interest in USEB that was acquired by Countryside Canada on closing of the Initial Offering.

"USEB Settlement" means an agreement with USEY and USEB resolving all outstanding issues between the Fund and certain of its subsidiaries, the Manager, USEY and USEB.

"**USE Canada**" means USE Canada Energy Corp.

"**USE Canada Holdings**" means USE Canada Holdings Corp.

"**USEY**" means U.S. Energy Systems, Inc.

Schedule A: Joint Audit Committee Charter

COUNTRYSIDE POWER INCOME FUND
AND
COUNTRYSIDE CANADA POWER INC.

RESTATED AND AMENDED JOINT AUDIT COMMITTEE

CHARTER

The RESTATED AND AMENDED Joint Audit Committee (the "**Committee**") of Countryside Power Income Fund (the "**Fund**") and Countryside Canada Power Inc. ("**Countryside Canada**") is established in order to assist the board of trustees of the Fund and the board of directors of Countryside Canada in their oversight activities. This Restated and Amended Charter of the Joint Audit Committee is intended to update the Charter of the Joint Audit Committee so that it is consistent with (a) the management arrangements set forth in (i) the Management Agreement by and among Countryside Ventures LLC ("Countryside Ventures"), Countryside Canada Power, Inc., ("Countryside Canada") and Countryside US Holding Corp. ("Countryside Holding") dated as of November 1, 2005 (the "Management Agreement")and (ii) the Management and Administration Agreement by and among Countryside Canada Ventures, Inc ("Countryside Canada Ventures" and together with Countryside Ventures, the "Manager"), the Fund and Countryside Canada as of even date and (b) National Policy 58-201, Corporate Governance Guidelines. The purpose of the Committee is to assist such boards in fulfilling their responsibilities of oversight and supervision of:

- the integrity of the Fund and Countryside Canada's accounting and financial reporting practices and procedures,
- the adequacy of the Fund and Countryside Canada's internal accounting controls and procedures management information systems
- the quality and integrity of the Fund and Countryside Canada's consolidated financial statements, and
- the independence and performance of the Fund's and Countryside Canada's independent auditor.

Composition:

- The board of trustees of the Fund and the board of directors of Countryside Canada shall elect annually from among their members a committee to be known as the Joint Audit Committee to be composed of three persons who are both independent trustees of the Fund and independent directors of Countryside Canada and each of whom is financially literate (or will become so within a reasonable period of time following his or her appointment).

- A member of the Committee who sits on the board or directors/trustees of an affiliated entity is exempt from the requirement that he or she be independent if that member, except for being a director/trustee (or member of the audit committee or any other board committee) of the Fund and the affiliated entity, is otherwise independent of the Fund and the affiliated entity, provided that the boards have determined that appointing such member to the Committee will not materially adversely affect the ability of the Committee to act independently.

- If a member of the Committee ceases to be independent for reasons outside that member's reasonable control, that member is exempt from the requirement to be independent for a period ending on the later of:

  (i) the next annual meeting of the Fund; and
  (ii) the date that is six months from the occurrence of the event which caused the member to not be independent,

  provided that the board of trustees of the Fund and the board of directors of Countryside Canada have determined that appointing such member to the Committee will not materially adversely affect the ability of the Committee to act independently.

- Where the death, disability or resignation of a member of the Committee has resulted in a vacancy on the Committee that the boards are required to fill, a member appointed to fill such vacancy is exempt from the requirements to be independent and financially literate for a period ending the later of:

  (i) the next annual meeting of the Fund; and
  (ii) the date that is six months from the day the vacancy was created,

  provided that the board of trustees and the board of directors of Countryside Canada have determined that appointing such member to the Committee will not materially adversely affect the ability of the Committee to act independently.

Reports:

The Joint Audit Committee shall report to the board of trustees of the Fund and the board of directors of Countryside Canada on a regular basis and, in any event, before the public disclosure by the Fund of its quarterly and annual financial results. The reports of the Joint Audit Committee shall include any issues of which the Committee is aware with respect to the quality or integrity of the Fund's and Countryside Canada's consolidated financial statements, their compliance with legal or regulatory requirements, and the performance and independence of the Fund's and Countryside Canada's independent auditor.

Responsibilities:

Subject to the powers and duties of the board of trustees of the Fund and the board of directors of Countryside Canada, the board of trustees and the board of directors of Countryside Canada hereby delegate to the Committee the following powers and duties to be performed by the Committee on behalf of and for the board of trustees of the Fund and the board of directors of Countryside Canada:

A. Financial Statements and Other Financial Information

The Committee shall:

(i) review the Fund's and Countryside Canada's consolidated annual audited financial statements and related documents prior to any public disclosure of such information;

(ii) review the Fund's and Countryside Canada's consolidated interim unaudited financial results and related documents prior to any public disclosure;

(iii) following a review with the Manager and the independent auditors of such annual and interim consolidated financial statements and related documents recommend to the board of trustees of the Fund and the board of Countryside Canada the approval of such financial statements and related documents;

(iv) review with the Manager and/or the independent auditors all critical policies and practices used as well as significant management estimates and judgments and any changes in accounting policies or financial reporting requirements that may affect the Fund's and Countryside Canada's consolidated financial statements;

(v) review with the Manager and/or the independent auditors the treatment in the financial statements of any significant transactions, and other potentially difficult matters;

(vi) review a summary provided by the Fund's legal counsel of the status of any material pending or threatened litigation, claims and assessments respecting the Fund and its subsidiaries;

(vii) discuss the annual financial statements and the auditors' report thereon with the Manager and the auditors; and

(viii) review the other annual financial reporting documents as well as management's discussion and analysis and earnings press releases of the Fund and Countryside Canada prior to any disclosure to the public.

B. Financial Reporting Control Systems

The Committee shall:

(i) require the Manager to implement and maintain appropriate internal controls, and use reasonable efforts to satisfy itself as to the adequacy of the Fund's and Countryside Canada's policies for the management of risk and the preservation of assets and the fulfillment of legislative and regulatory requirements;

(ii) annually, in consultation with the Manager, the independent auditors and if applicable the officer or employee responsible for the internal audit function, review, evaluate and assess the adequacy and integrity of the Fund's and Countryside Canada's consolidated financial reporting processes and internal controls; discuss significant financial risk, exposures and the steps the Manager has taken to monitor, control and report such exposures;

(iii) if applicable, meet separately with the Manager, or if appropriate the Fund employee responsible for the internal audit function to discuss any matters that the Committee or auditors believe should be discussed in private;

(iv) submit to the board of trustees and the boards of directors of Countryside Canada and its subsidiaries any recommendations the Committee may have from time to time with respect to financial reporting, accounting procedures and policies and internal controls;

(v) review reports from the Manager outlining any significant changes in financial risks facing the Fund;

(vi) review the management letter of the independent auditors and the responses to suggestions made;

(vii) review any new appointments to senior positions of the Fund and its subsidiaries or the Manager with financial reporting responsibilities;

(viii) satisfy itself that adequate procedures are in place for the review of the Fund's disclosure of the Fund's financial information extracted or derived from the Fund's consolidated financial statements (other than the financial statements, management's discussion and analysis and earnings press releases) and periodically assess the adequacy of those procedures;

(ix) establish procedures for:

   a) the receipt, retention and treatment of complaints received by the Fund or its subsidiaries or the Manager regarding accounting, internal accounting controls, or auditing matters; and

   b) the confidential, anonymous submission by employees of the Fund or its subsidiaries or the Manager of concerns regarding questionable accounting or auditing matters.

(x) review and approve the Fund's (and its respective subsidiaries') hiring policies regarding employees and former employees of the present and former independent auditors of the issuer;

(xi) obtain assurance from independent auditors regarding the overall control environment and the adequacy of accounting system controls.

C. *Independent Auditor*

The Committee shall:

(i) review the audit plan with the independent auditors;

(ii) discuss in private with the independent auditors matters affecting the conduct of their audit and other corporate matters;

(iii) review the performance and the remuneration of the Fund's and Countryside Canada's auditors;

(iv) recommend to the board of trustees of the Fund and the board of directors of Countryside Canada each year the retention or replacement of the independent auditors to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Fund and Countryside Canada;

(v) if there is a plan to change auditors, review all issues related to the change and the steps planned for an orderly transition;

(vi) annually review and recommend for approval to the trust Unitholders the terms of engagement and the remuneration of the independent auditor;

(vii) oversee the work of the independent auditors engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Fund and Countryside Canada, including the resolution of disagreements between the Manager and the independent auditors regarding financial reporting;

(viii) discuss with the Fund's and Countryside Canada's auditors the quality and not just the acceptability of the Fund's accounting principles;

(ix) meet with the Fund's and Countryside Canada's auditors on a regular basis in the absence of the Manager;

(x) relay its expectations to the Fund's and Countryside Canada's auditors from time to time including its expectation that (i) any disagreements of a material nature with the Manager be brought to the attention of the Committee, (ii) that the auditors are accountable to the Committee and the board, each as representatives of the trust Unitholders and must report directly to the Committee, (iii) any irregularities in the financial information be reported to the Committee, (iv) the auditors explain the process undertaken by them in auditing or reviewing the Fund's financial disclosure, (v) the auditors disclose to the Committee any significant changes to accounting policies or treatment of the Fund, (vi) the auditors disclose to the Committee anŷ reservations they may have about the financial statements or their access to materials and/or persons in reviewing or auditing such statements, and (vii) the auditors disclose any conflict of interest that may arise in their engagement; and

(xi) review at least annually the non-audit services provided by the Fund's and Countryside Canada's auditors for the purposes of getting assurance that the performance of such services will not compromise the independence of the independent auditors;

(xii) pre-approve all non-audit services to be provided to the Fund or its subsidiary entities[8] by its independent auditors or the independent auditors of its subsidiary entities provided that the Committee may delegate to one or more independent members the authority to pre-approve non-audit services in satisfaction of this requirement. The pre-approval of non-audit services by any member to whom authority has been delegated must be presented to the full Committee at its first scheduled meeting following such pre-approval.

Structure:

- The Committee shall appoint one of its members to act as Chairman of the Committee. The Chairman will appoint a secretary who will keep minutes of all meetings (the "**Secretary**"). The Secretary does not have to be a member of the Committee or a trustee and can be changed by simple notice from the Chairman.

- The Committee will meet as many times as is necessary to carry out its responsibilities but in no event will the Committee meet less than once a year. Meetings will be at the call of the Chairman. Notwithstanding the foregoing, the auditors of the Fund and Countryside Canada or any member of the Committee may call a meeting of the Committee on not less than 48 hours' notice.

- No business may be transacted by the Committee except at a meeting of its members at which a quorum of the Committee is present or by a resolution in writing signed by all the members of the Committee. A majority of the members of the Committee shall constitute a quorum provided that if the number of members of the Committee is an even number one half of the number of members plus one shall constitute a quorum.

- Any member of the Committee may be removed or replaced at any time by the board of trustees of the Fund and the board of directors of Countryside Canada and shall cease to be a member of the Committee as soon as such member ceases to be a trustee or a director of Countryside Canada. Subject to the foregoing, each member of the Committee shall hold such office until the next annual meeting of Unitholders after his or her election as a member of the Committee.

[8]The Committee may satisfy the pre-approval requirement if: (a) the aggregate amount of all the non-audit services that were not pre-approved constitutes no more than five per cent of the total amount of revenues paid by the Fund and Countryside Canada to its independent auditors during the fiscal year in which the services are provided; (b) the services were not recognized by the Fund and Countryside Canada at the time of the engagement to be non-audit services; and (c) the services are promptly brought to the attention of the Committee and approved, prior to the completion of the audit, by the Committee or by one or more members of the Committee to whom authority to grant such approvals has been delegated by the Committee.

- The auditors of the Fund and Countryside Canada shall be entitled to receive notice of every meeting of the Committee and, at the expense of the Fund, to attend and be heard thereat.

- The time at which and the place where the meetings of the Committee shall be held, the calling of meetings and the procedure in all respects of such meeting shall be determined by the Committee, unless otherwise provided for in the Declaration of Trust and the by-laws of Countryside Canada, or otherwise determined by resolution of the board of trustees.

- The members of the Committee shall be entitled to receive such remuneration for acting as members of the Committee as the board of trustees and the board of directors of Countryside Canada may from time to time determine.

Independent Advice:

In discharging its mandate the Committee shall have the authority to retain and receive advice from special legal, accounting or other advisors.

Annual Evaluation:

At least annually, the Committee shall, in a manner it determines to be appropriate:

- perform a review and evaluation of the performance of the Committee and its members, including the compliance of the Committee with its terms of reference.

- review and assess the adequacy of its terms of reference and recommend to the board of trustees and the board of directors of Countryside Canada any improvements to its terms of reference that the Committee determines to be appropriate.

Limitation:

Nothing in this charter is intended to or shall have the effect of limiting or impairing the independent decision making authority or responsibility of any board of directors of a Fund subsidiary mandated by applicable law.

Severance:

At any time the Board of Trustees of the Fund or the Board of Directors of Countryside Canada may determine to establish its own Audit Committee in which case the mandate for this Joint Audit Committee shall terminate.

Definitions:

"**financially literate**" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Fund's and Countryside Canada consolidated financial statements.

"**independent trustee**" means a trustee who has no direct or indirect material relationship with the Fund or its affiliates, the Manager or U.S. Energy Systems, Inc. ("**USEY**"), Cinergy Corp. ("**Cinergy**") and U.S. Energy Biogas Corporation ("**USEB**") or their affiliates.

"**material relationship**" means a relationship which could, in the view of the board of trustees of the Fund and Countryside Canada's board of directors, reasonably interfere with the exercise of a committee member's independent judgment. Without limiting the generality of the foregoing, the following persons are considered to have a material relationship with the Fund, USEY, Cinergy or USEB:

(a) a person who is, or has been, an employee or executive officer of the Fund, the Manager, USEY, Cinergy or USEB, or any of their subsidiary entities or affiliated entities, unless the prescribed period has elapsed since the end of the service or employment;

(b) a person whose immediate family member is, or has been, an executive officer of the Fund, the Manager, USEY, Cinergy or USEB, or any of their subsidiary or affiliated entities, unless the prescribed period has elapsed since the end of the service or employment;

(c) a person who is, or has been, an affiliated entity of, a partner[2] of, or employed by, a current or former internal or independent auditor of the Fund, the Manager, USEY, Cinergy or USEB unless the prescribed period has elapsed since the person's relationship with the internal or independent auditor, or the auditing relationship has ended;

(d) a person whose immediate family member is, or has been, an affiliated entity of, a partner of, or employed in a professional capacity by, a current or former internal or independent auditor of the Fund, the Manager, USEY, Cinergy or USEB, unless the prescribed period has elapsed since the person's relationship with the internal or independent auditor, or the auditing relationship, has ended;

[2] "partner" does not include a fixed income partner whose interest in the internal or independent auditor is limited to the receipt of fixed amounts of compensation (including deferred compensation) for prior service with an internal or independent auditor if the compensation is not contingent in any way on continued services.

(e) a person who is, or has been, or whose immediate family member is, or has been, an executive officer of an entity if any of the Fund, the Manager, USEY, Cinergy or USEB or their subsidiaries' current executives serve on the entity's compensation committee, unless the prescribed period has elapsed since the end of the service or employment;

(f) a person who has a relationship with the Fund, the Manager, USEY, Cinergy or USEB or their affiliated entities pursuant to which such person may accept, directly or indirectly[3], any consulting, advisory or other compensatory fee from the Fund, USEY, Cinergy or USEB or any of their subsidiaries, other than as remuneration for acting in his or her capacity as a member of the board of directors or any other board committee, or as part-time chair or vice chair of the board or any board committee;

(g) a person who receives, or whose immediate family member receives, more than $75,000 per year in direct compensation from the Fund, the Manager, USEY, Cinergy or USEB or their subsidiary entities, other than as remuneration for acting in his or her capacity as member of the board of directors or any board committee, unless the prescribed period has elapsed

(h) since he or she ceased to receive more than $75,000 per year in such compensation;

(i) a person who is an affiliated entity of the Fund, the Manager, USEY, Cinergy or USEB or any of their subsidiary entities.

"**prescribed period**" means the shorter of:

(a) the period commencing on March 30, 2004 and ending immediately prior to the determination required under the definition of "material relationship"; and

(b) the three-year period ending immediately prior to the determination required under the definition of "material relationship".

[3] The indirect acceptance by a person of a consulting, advisory or other compensatory fee includes acceptance of a fee by:

(a) a person's spouse, minor child or stepchild or a child or stepchild who shares the person's home, or

(b) an entity in which such person is a partner, member, an officer such as a managing director occupying a comparable position or executive officer or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in such case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the Fund, the Manager, USEY, Cinergy or USEB or any of their subsidiaries.

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Form 5 Submission - Dividend/Distribution Declaration

Issuer : Countryside Power Income Fund

Security Symbol	Amount	Currency	Declaration Date	Record Date	Payable Date
COU.UN	.0863	CDN	03/21/2007	03/30/2007	04/30/2007

Filed on behalf of the Issuer by:

Name:	Natalie Miller
Phone:	519-435-0298
Email:	nmiller@countrysidepowerfund.com
Submission Date:	
Last Updated:	03/21/2007

Form 1 Submission - Change in Issued and Outstanding Securities

Issuer :	Countryside Canada Power Inc.
Symbol :	CSD.DB.U
Reporting Period:	02/01/2007 - 02/28/2007

Summary

Issued & Outstanding Opening Balance :	441,610	As at :	02/01/2007
	Effect on Issued & Outstanding Securities		
Other Issuances and Cancellations	0		
Issued & Outstanding Closing Balance :	441,610		

Other Issuances and Cancellations

Effective Date	Transaction Type	Number of Securities
Totals		0

Filed on behalf of the Issuer by:

Name:	Natalie Miller
Phone:	519-435-0298
Email:	nmiller@countrysidepowerfund.com
Submission Date:	
Last Updated:	03/09/2007

Form 1 Submission - Change in Issued and Outstanding Securities

Issuer :	Countryside Power Income Fund
Symbol :	COU.UN
Reporting Period:	02/01/2007 - 02/28/2007

Summary

Issued & Outstanding Opening Balance :	20,812,097	As at :	02/01/2007
	Effect on Issued & Outstanding Securities		
Other Issuances and Cancellations	0		
Issued & Outstanding Closing Balance :	20,812,097		

Other Issuances and Cancellations

Effective Date	Transaction Type	Number of Securities
Totals		0

Filed on behalf of the Issuer by:

Name:	Natalie Miller
Phone:	519-435-0298
Email:	nmiller@countrysidepowerfund.com
Submission Date:	
Last Updated:	03/09/2007

Form 1 Submission - Change in Issued and Outstanding Securities

Issuer :	Countryside Power Income Fund
Symbol :	COU.UN
Reporting Period:	01/01/2007 - 01/31/2007

Summary

Issued & Outstanding Opening Balance :	20,812,097	As at :	01/01/2007
	Effect on Issued & Outstanding Securities		
Other Issuances and Cancellations	0		
Issued & Outstanding Closing Balance :	20,812,097		

Other Issuances and Cancellations

Effective Date	Transaction Type	Number of Securities
·tals		0

Filed on behalf of the Issuer by:

Name:	Natalie Miller
Phone:	519-435-0298
Email:	nmiller@countrysidepowerfund.com
Submission Date:	
Last Updated:	02/16/2007

Form 1 Submission - Change in Issued and Outstanding Securities

Issuer :	Countryside Canada Power Inc.
Symbol :	CSD.DB.U
Reporting Period:	01/01/2007 - 01/31/2007

Summary

Issued & Outstanding Opening Balance :	441,610	As at :	01/01/2007
	Effect on Issued & Outstanding Securities		
Other Issuances and Cancellations	0		
Issued & Outstanding Closing Balance :	441,610		

Other Issuances and Cancellations

Effective Date	Transaction Type	Number of Securities
,tals		0

Filed on behalf of the Issuer by:

Name:	Natalie Miller
Phone:	519-435-0298
Email:	nmiller@countrysidepowerfund.com
Submission Date:	02/16/2007
Last Updated:	02/16/2007

Form 5 Submission - Dividend/Distribution Declaration

Issuer : Countryside Power Income Fund

Security Symbol	Amount	Currency	Declaration Date	Record Date	Payable Date
COU.UN	.0863	CDN	02/27/2007	03/08/2007	03/30/2007

Filed on behalf of the Issuer by:

Name: Douglas Drummond
Phone: 5194350298
Email: ddrummond@countrysidepowerfund.com
Submission Date:
Last Updated: 02/27/2007

Form 5 Submission - Dividend/Distribution Declaration

Issuer : Countryside Power Income Fund

Security Symbol	Amount	Currency	Declaration Date	Record Date	Payable Date
COU.UN	.0863	CDN	02/01/2007	02/08/2007	02/28/2007

Filed on behalf of the Issuer by:

Name:	Nicole Archibald
Phone:	5194350298
Email:	narchibald@countrysidepowerfund.com
Submission Date:	
Last Updated:	02/01/2007

NOT FOR DISTRIBUTION IN THE UNITED STATES OR OVER
UNITED STATES WIRE SERVICES

COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund Announces Lender Approval of USEB Settlement

Lenders Extend Waiver Period and Reinstate Access to Credit Facility

(London, Ontario, January 26, 2007) – Countryside Power Income Fund (TSX: COU.UN) (the "Fund") today announced that its lending syndicate has approved the previously disclosed settlement agreement among the Fund's subsidiary, Countryside Canada Power Inc. (the "Lender"), U.S. Energy Biogas Corp. ("USEB") and its parent, U.S. Energy Systems, Inc.

The USEB Settlement Agreement, reached on January 13, 2007, provides, among other things, for the Lender to have an allowed secured claim of US$99,000,000 (approximately CAD$116,500,000 at the current exchange rate) in the bankruptcy proceedings of USEB and its subsidiaries. The USEB Settlement Agreement has been approved by the respective company boards and remains subject to the approval of The United States Bankruptcy Court in the Southern District of New York overseeing USEB's Chapter 11 reorganization case, scheduled for February 1, 2007.

As of January 25, 2007, the Fund's lending syndicate approved both the terms of the USEB Settlement Agreement and an extension of the prior waiver of the cross-default provisions of the credit agreement to May 31, 2007. The cross-default provisions were triggered by both USEB's filing for reorganization and its non-payment of debt service on November 29, 2006. The terms of the current waiver extension and amendment will primarily grant the Fund immediate access to its credit facility commitment (subject to certain restrictions) and permits the Fund, at its sole discretion, to make monthly distribution payments to unitholders during the waiver period. In consideration for the waiver extension and amendment, the Lender will pledge, among other things, its direct ownership interests and secured note held in Countryside U.S. Holding Corp., which is the primary holding company of the Fund's California cogeneration assets (Ripon Cogeneration LLC). The closing of the waiver extension and amendment to the Fund's credit agreement is expected to occur on or before January 30, 2007.

During the extended waiver period, the Fund will seek a long-term financing arrangement that reflects the expected monetization of the USEB secured claim under the USEB Settlement Agreement and provides the Fund with sufficient credit capacity to meet its growth commitments, including the full funding of construction of the new London cogeneration facility scheduled to be completed in 2008. There can be no assurance as to the outcome of these discussions with the lenders or that the expected monetization will occur.

Forward-Looking Statements

This press release may contain forward-looking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time to time in the Fund's annual information form dated March 31, 2006, and available on SEDAR. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

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Further information:

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Nicole Archibald
Vice President, Administration
Countryside Canada Ventures Inc.
Tel: 519-435-0298
info@countrysidepowerfund.com

FORM 51-102F3

MATERIAL CHANGE REPORT

Item 1 Name and Address of Company

Countryside Power Income Fund
495 Richmond Street, Suite 920
London, Ontario
N6A 5A9

Item 2 Date of Material Change

February 9, 2007

Item 3 News Release

A press release was issued on February 9, 2007 in London, Ontario and disseminated across Canada by CCNMathews, which is attached hereto as Schedule "A".

Item 4 Summary of Material Change

Countryside Power Income Fund (together with its subsidiaries, (collectively the "Fund")) has engaged Lehman Brothers Inc. to assist the board of trustees with its ongoing process of identifying and considering strategic alternatives available to the Fund to maximize unitholder value. The Fund also entered into an amendment to the management agreement dated September 23, 2005, between subsidiaries of the Fund and Countryside Ventures LLC (the "Manager") (and collectively the "Management Agreement") resulting from the waiver and amendment recently granted by its syndicate of lenders.

Item 5 Full Description of Material Change

Review of Strategic Alternatives

The strategic review process has been advanced and formalized in response to: (i) the expected impact to the Fund of the recent ruling by the US Bankruptcy Court indicating that it is prepared to enter an order approving the U.S. Energy Biogas Corp. ("USEB") settlement and (ii) the Canadian government's proposed legislation to tax income trusts. The strategic review process is intended to consider a range of value enhancement alternatives that will involve a comprehensive review of the Fund's existing capital structure, growth strategy, and access to capital markets as well as prospects as an income trust. The process will also consider such alternatives as a sale of the Fund (or its segments), a conversion to a corporate structure, and/or a recapitalization. As part of the process, the Fund will consider the best use of proceeds for the expected cash monetization of its remaining US$96 million (CAD$113 million) secured claim in USEB. The Fund expects to conclude its strategic review process by the end of March 2007. There can be no assurance that the evaluation process will result in a decision regarding any transaction or that it will be completed in the specified time frame.

Amendment to Management Agreement

As of January 25, 2007, the Fund's lending syndicate approved, among other things, an extension of the prior waiver of the cross-default provisions of the credit agreement to May 31, 2007. In consideration for the waiver extension, the Fund was required to pledge the Ripon-related assets, and the Manager was required to waive certain existing rights with respect to the Manager's 25% subordinated interest in Ripon Power LLC, which was originally provided as consideration to the Manager in connection with the origination and acquisition of Ripon in 2005 (the "Manager's Subordinated Interest"). The Fund holds the remaining 75% of the subordinated interest in Ripon Power LLC. At the time of the waiver and in order to accommodate the lending syndicate's requirement, the board of trustees of the Fund entered into an agreement with the Manager to purchase, on June 29, 2007 (or before in certain circumstances), 85% of the Manager's Subordinated Interest for cash and Fund units equal to $16,026,111 based on a unit price of $8.32. The agreement is attached hereto as Schedule "B". Under the prior arrangement, the Manager's Subordinated Interest could be exchanged for units of the Fund on or after June 29, 2007 (or before in certain circumstances) at the option of either the Fund or the Manager (subject to regulatory approval). The consideration to be paid will comprise a minimum of 10% cash and will provide the Fund with an option to increase the cash component up to 25% of the total consideration if the board of trustees deems such payment to be economically beneficial to the Fund.

After completion of the purchase of the 85% of the Manager's Subordinated Interest, the Manager will hold 3.75% and the Fund will hold 96.25%, respectively, of the subordinated interest in Ripon Power LLC. The board of trustees believes that the retained Manager's Subordinated Interest will help ensure a continued focus by the Manager on potential Ripon-related growth opportunities. The Fund and the Manager have also agreed that, absence a change of control, neither party will exercise its option to exchange the remaining 15% of the Manager's Subordinated Interest until February 9, 2009.

In determining that it is in the best interests of the Fund to enter into the amendment, the board of trustees took into account, among other things: (i) the importance of the waiver extension from the lending syndicate to permit the Fund to avoid a default and consequent enforcement actions under its senior credit facility, maintain access to liquidity, pay distributions, continue the development of the London cogeneration project on schedule and accommodate an orderly strategic review process, (ii) that the purchase price and the timing of the transaction is substantially consistent with the consideration and timing contemplated in the existing Management Agreement, (iii) that the amendment serves to further align the interests of the Manager and the unitholders of the Fund. As part of its decision to enter into this agreement, the board of trustees sought and received an opinion as to the fairness of the consideration to be paid in connection with the amendment to the Management Agreement.

After completion of the transaction, the Manager will hold between 1,444,934 and 1,733,921 units of the Fund, (with the exact number of units to be issued based on the final determination of the cash component) which after giving effect to the transaction and based on the number of units outstanding today, would result in the Manager holding between 6.5% and 7.7% of the outstanding units. The Manager is owned by Messrs. Goran Mornhed, Edward Campana and Allen Rothman.

The transaction may be a related party transaction under Ontario Securities Commission Rule 61-501 and Québec Regulation Q-27 (the "Related Party Rules"). In certain circumstances, the Related Party Rules require a formal valuation and minority approval in respect of a related party transaction. The Related Party Rules provide an exemption from the requirements to obtain a formal valuation report and minority approval in the event that neither the fair market value of the subject matter of, nor the fair market value of the consideration for, the transaction, insofar as it involves related parties, exceeds 25% of the issuer's market capitalization. The Fund has determined that neither the fair market value of the Manager's Subordinated Interest to be purchased, nor the fair market value of the consideration being paid for such interest, exceeds 25% of the market capitalization of the Fund.

Item 6 Reliance on subsection 7.1(2) or (3) of National Instrument 51-102

Not applicable.

Item 7 Omitted Information

None.

Item 8 Senior Officer

The following senior officer of Countryside Ventures LLC is knowledgeable about the material change and this report:

Edward Campana
Tel: 914.993.5010
Fax: 914.993.6449

Item 9 Date of Report

February 16, 2007.

Schedule "A"
Press Release

(London, Ontario, February 9, 2007) Countryside Power Income Fund (TSX: COU.UN) together with its subsidiaries, (collectively the "Fund") announced today that the board of trustees has engaged Lehman Brothers Inc. to assist the board of trustees with its ongoing process of identifying and considering strategic alternatives available to the Fund to maximize unitholder value. The Fund also announced today an amendment to the management agreement dated September 23, 2005, between subsidiaries of the Fund and Countryside Ventures LLC (the "Manager") (and collectively the "Management Agreement") resulting from the waiver and amendment recently granted by its syndicate of lenders.

Review of Strategic Alternatives

The strategic review process has been advanced and formalized in response to: (i) the expected impact to the Fund of the recent ruling by the US Bankruptcy Court indicating that it is prepared to enter an order approving the U.S. Energy Biogas Corp. ("USEB") settlement (see press release dated February 2, 2007) and (ii) the Canadian government's proposed legislation to tax income trusts. The strategic review process is intended to consider a range of value enhancement alternatives that will involve a comprehensive review of the Fund's existing capital structure, growth strategy, and access to capital markets as well as prospects as an income trust. The process will also consider such alternatives as a sale of the Fund (or its segments), a conversion to a corporate structure, and/or a recapitalization. As part of the process, the Fund will consider the best use of proceeds for the expected cash monetization of its remaining US$96 million (CAD$113 million) secured claim in USEB. The Fund expects to conclude its strategic review process by the end of March 2007. There can be no assurance that the evaluation process will result in a decision regarding any transaction or that it will be completed in the specified time frame.

Amendment to Management Agreement

As of January 25, 2007, the Fund's lending syndicate approved, among other things, an extension of the prior waiver of the cross-default provisions of the credit agreement to May 31, 2007. In consideration for the waiver extension, the Fund was required to pledge the Ripon-related assets, and the Manager was required to waive certain existing rights with respect to the Manager's 25% subordinated interest in Ripon Power LLC, which was originally provided as consideration to the Manager in connection with the origination and acquisition of Ripon in 2005 (the "Manager's Subordinated Interest"). The Fund holds the remaining 75% of the subordinated interest in Ripon Power LLC. At the time of the waiver and in order to accommodate the lending syndicate's requirement, the board of trustees of the Fund entered into an agreement with the Manager to purchase, on June 29, 2007 (or before in certain circumstances), 85% of the Manager's Subordinated Interest for cash and Fund units equal to $16,026,111 based on a unit price of $8.32. Under the prior arrangement, the Manager's Subordinated Interest could be exchanged for units of the Fund on or after June 29, 2007 (or before in certain circumstances) at the option of either the Fund or the Manager (subject to regulatory approval). The consideration to be paid will comprise a minimum of 10% cash and will provide the Fund with an option to increase the cash component up to 25% of the total consideration if the board of trustees deems such payment to be economically beneficial to the Fund.

Schedule "B"

FIRST AMENDMENT TO THE MANAGEMENT AGREEMENT

THIS AMENDING AGREEMENT (this "**Amendment**") made as of the 9th day of February, 2007.

B E T W E E N:

COUNTRYSIDE VENTURES LLC, a limited liability corporation existing under the laws of the State of Delaware,

(the "**Manager**")

– and –

COUNTRYSIDE US HOLDING CORP., a corporation existing under the laws of the State of Delaware,

("**Countryside US**")

– and –

COUNTRYSIDE CANADA POWER INC., a corporation existing under the laws of the Province of Ontario,

("**Countryside Canada**")

– and –

COUNTRYSIDE POWER INCOME FUND, an unincorporated trust existing under the laws of the Province of Ontario,

(the "**Fund**" and, together with Countryside US and Countryside Canada, "**Countryside**")

WHEREAS the Trustees have determined that it is in the best interests of the Fund and its unitholders to obtain a waiver from Countryside's lending syndicate of certain defaults under its credit facilities,

AND WHEREAS Countryside's lending syndicate, as part of the process of granting Countryside a waiver of those defaults, has requested that the Manager concede significant rights and protections respecting the Manager's interest (the "**Ripon Interest**") under the operating agreement that governs Ripon Power LLC ("**Ripon**"), which concessions would have a materially adverse impact on the value of such Ripon Interest,

AND WHEREAS, in the context of the foregoing, the trustees of the Fund (the "**Trustees**") have requested that the Manager agree to certain changes and adjustments to the management agreement (the "**Management Agreement**") made as of the 23rd day of September

2005 between the Manager, Countryside US and Countryside Canada, which would permit Countryside to purchase the 85% Interest (as defined below),

AND WHEREAS the Trustees made the foregoing request because they believe that the changes and adjustments would

- permit Countryside to obtain the waiver from its lending syndicate,
- substantially address the Manager's concerns with granting the above-noted concessions,
- substantially effectuate the arrangement between Countryside and the Manager currently set out in the Management Agreement in respect of the Exchange Option relating to the Ripon Interest, and
- be in the best interests of the Fund and its unitholders,

AND WHEREAS the Manager is agreeable to the changes and the adjustments to the Management Agreement,

NOW THEREFORE in consideration of the premises and the mutual covenants and agreements herein contained, and other good and valuable consideration, the sufficiency of which is hereby acknowledged by each of the parties to this Amendment, the parties agree as follows:

ARTICLE 1 – DEFINITIONS AND INTERPRETATION

1.01 Definitions

Any capitalized term used in this Amendment that is not otherwise defined herein shall have the meaning set out in the Management Agreement.

1.02 Headings

The division of this Amendment into articles, sections, paragraphs and subparagraphs and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Amendment.

ARTICLE 2 – PURCHASE OF THE 85% INTEREST

2.01 Purchase of 85% Interest

Notwithstanding the terms of the Management Agreement, the parties agree that, on the Trigger Date (as defined below), on not less than two business days' notice to the other parties, Countryside US will acquire from the Manager, and the Manager will sell to Countryside US, 85% of the Manager's Ripon Interest (the "**85% Interest**") in consideration for 1,444,934 Units, subject to adjustment pursuant to Section 2.02, and a cash payment of $4,006,528. Notwithstanding the prior sentence, at Countryside's sole discretion, Countryside may elect, in lieu of paying up to 60% of the cash payment, to issue up to an additional 288,787 Units to the

Manager (such Units to be valued at a price of $8.32 for this purpose of reducing the amount of the cash payment). For the purposes of this Amendment, "**Trigger Date**" shall mean the earlier of (i) June 29, 2007; and (ii) upon the fifth business day prior to the occurrence of a Change of Control.

2.02 Adjustment Provision

In case the Fund after the date of hereof takes any action affecting the Units, other than in the context of a Change of Control, including but not limited to any (i) subdivision, consolidation, combination, reduction, reclassification or redivision of the outstanding Units of the Fund; (ii) the issuance or distribution by the Fund of Units (or securities exchangeable for or convertible into Units) to all or substantially all the holders of Units by way of a stock dividend or other distribution; (iii) the issue of rights, options or warrants to all or substantially all of the holders of Units entitling them within a period of 45 days to acquire Units (or securities exchangeable for or convertible into Units) at less than 90% of the fair market price; (iv) the issuance or distribution to all or substantially all the holders of Units, securities other than Units or rights, options or warrants (other than those described in (iii)) or of property or other assets (including evidences of indebtedness); (v) an amalgamation, merger or arrangement of the Fund with another entity; (vii) a transfer of all or substantially al of the assets of the Fund; or (viii) any other action or event not described in (i) through (vii) of this Section 2.02, which would materially affect the rights of the Manager to receive Units pursuant to Section 2.01 of this Amendment, the number of Units will be adjusted in such manner and at such time, so as to place the Manager in the same position in all material respects as if the Units were issued to the Manager on the date hereof, subject in all cases to any necessary regulatory approval.

2.03 Notice of Adjustment

Upon any adjustment of the number of Units, then and in each such case the Fund shall give written notice thereof to the Manager, which notice shall state the number of Units resulting from such adjustment, and shall set forth in reasonable detail the method of calculation and the facts upon which such calculation is based.

2.04 No Further Rights in respect of 85% Interest, etc.

The Manager agrees that, from and after the date of this Amendment, it will have no further right to any distributions in respect of the 85% Interest.

The Manager also agrees that, from and after the date of this Amendment, except with respect to distributions on the remaining 15% of the Manager's Ripon Interest and subject to the full performance of the obligations of Countryside pursuant to Section 2.01, it will have no rights with respect to any improvement of Ripon. With respect to the remaining 15% of the Manager's Ripon Interest, the Manager agrees that, notwithstanding Section 3.03(a) (but subject to Section 3.03(b) and (c)) of the Management Agreement, neither the Manager nor Countryside will exercise the Exchange Option prior to February 9, 2009.

2.05 Place of Closing

The closing shall take place at 9:00 a.m. on the second business day after either party exercises its exchange right pursuant to Section 2.01 at the Toronto offices of Goodmans LLP or at such other place and time as may be agreed upon by the parties.

2.06 Deliveries at Closing

The Manager shall transfer and deliver to Countryside US at the time of closing such documents that are necessary or advisable to transfer and assign all of the Manager's right, title and interest in Ripon, including all rights and obligations pursuant to the operating agreement governing Ripon. Countryside shall take such steps as shall be necessary or advisable to (i) cause the Fund to enter the Manager upon the books of the Fund as the holder of 1,443,932 Units, (or such greater number that Countryside may elect pursuant to Section 2.01), subject to adjustment pursuant to Section 2.02, and to issue a unit certificate (or other appropriate documentation) to the Manager representing such Units and (ii) deliver to the Manager by wire transfer the cash payment required by Section 2.01.

ARTICLE 3 – REPRESENTATIONS AND WARRANTIES

3.01 Representations and Warranties of the Manager

The Manager represents and warrants to Countryside (and acknowledges that Countryside is relying on the representations and warranties in completing the transactions contemplated by this Amendment) that:

(a) This Amendment constitutes a legal, valid, and binding obligation of the Manager, enforceable against it in accordance with its terms (subject, as to the enforcement of remedies, to bankruptcy, reorganization, insolvency, moratorium, and other laws relating to or affecting creditors' rights generally and subject to the availability of equitable remedies).

(b) The Manager is the only beneficial owner of the Ripon Interest in respect of Ripon free and clear of any encumbrances. There is no contract, option or other right of another binding upon or which at any time in the future may become binding upon the Manager to sell, transfer, assign, pledge, charge, mortgage or in any other way dispose of or encumber the Ripon Interest in respect of Ripon other than pursuant to this Agreement.

3.02 Representations and Warranties of Countryside

Countryside US, Countryside Canada and the Fund each represent and warrant to the Manager, jointly and severally (and acknowledge that the Manager is relying on the representations and warranties in completing the transactions contemplated by this Amendment) that:

(a) This Amendment constitutes a legal, valid, and binding obligation of the each of Countryside US, Countryside Canada and the Fund, enforceable against each in accordance with its terms (subject, as to the enforcement of remedies, to bankruptcy, reorganization, insolvency, moratorium, and other laws relating to or affecting creditors' rights generally and subject to the availability of equitable remedies).

(b) The Units when issued pursuant to this Amendment, will be validly issued and outstanding as fully paid and non-assessable Units of the Fund.

(c) The execution and delivery of this Amendment, the fulfilment of the terms hereof by each of Countryside US, Countryside Canada and the Fund and the issuance, sale and delivery of the Units pursuant to Section 2.01 to be issued by the Fund at the time of closing of the exercise of the Exchange Right do not and will not require the consent, approval, authorization, registration or qualification of or with any governmental authority, stock exchange, securities commission or other third party, except such as have been obtained or such as may be required (and shall be obtained prior to the time of closing) under applicable securities laws or stock exchange regulations.

ARTICLE 4 – LENDER CONSENT

4.01 Lender Consent

Each of the parties acknowledge and agree that the obligations of Countryside under Section 2.01 may be conditional upon Countryside receiving the prior consent of its lending syndicate pursuant to the existing credit facility of the Fund. To the extent that such consent is required, Countryside agrees to use its commercially reasonable efforts to obtain such consent if and when requested by the Manager. To the extent that such consent is required and has not been obtained, nothing under this Amendment shall in any way affect the rights and obligations of the parties pursuant to section 3.03 of the Management Agreement, provided that, for clarity, the parties hereby wish to confirm and agree that, in the event that distributions of the Fund are suspended, the number of Units shall be calculated as of the date immediately prior to such event.

4.02 New Credit Facility

In the event that Countryside replaces or restructures the existing credit facility, Countryside will cause the parties to the new or restructured credit facility (or other loan arrangement) consent and agree to the provisions of this Amendment. Furthermore, notwithstanding Section 4.01, upon the occurrence of a Change of Control, the purchase pursuant to Section 2.01 shall be completed immediately prior thereto or contemporaneously therewith and, for clarity, to the extent that such Change of Control results in all or substantially all of the outstanding Units being purchased or exchanged for cash and/or other consideration, the Manager shall be entitled to such per unit cash and/or other consideration in lieu of the Units contemplated in Section 2.01.

ARTICLE 5 – GENERAL MATTERS

5.01 Amendments

This Amendment shall not be amended or varied in its terms by oral agreement or by representations or otherwise except by instrument in writing executed by the duly authorized representatives of the parties hereto or their respective successors or assigns and, in the case of Countryside, approved by a majority of the Trustees.

5.02 Governing Law and Attornment

The provisions of this Amendment shall be governed by and interpreted in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein. Any legal actions or proceedings with respect to this Amendment shall be brought in the courts of the Province of Ontario. Each party hereby attorns to and accepts the exclusive jurisdiction of such courts.

5.03 Enurement

This Amendment shall enure to the benefit of and be binding upon the parties hereto and their respective successors and permitted assigns.

5.04 Entire Agreement

This Amendment constitutes the entire agreement between the parties hereto with respect to the subject matter hereof and cancels and supersedes any prior understanding and agreements between the parties hereto with respect thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements, express, implied or statutory, between the parties other than as expressly set forth in this Amendment.

5.05 Further Assurances

Each of the parties shall from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Amendment.

5.06 Time of the Essence

Time shall be of the essence in respect of this Amendment.

5.07 Counterparts

This Amendment may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

IN WITNESS WHEREOF the Parties hereto have executed this Amendment by their proper officers duly authorized in that behalf as of the day and year first above written.

COUNTRYSIDE VENTURES LLC

Per: *"Goran Mornhed"*

Name: Goran Mornhed
Title: President and Chief Executive Officer

COUNTRYSIDE US HOLDING CORP.

Per: *"James Sardo"*

Name: James Sardo
Title: Director

COUNTRYSIDE CANADA POWER INC.

Per: *"James Sardo"*

Name: James Sardo
Title: Director

COUNTRYSIDE POWER INCOME FUND

Per: *"James Sardo"*

Name: James Sardo
Title: Trustee

NOT FOR DISTRIBUTION IN THE UNITED STATES OR OVER
UNITED STATES WIRE SERVICES

COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund Confirms Cash Distribution for December 2006

US$3 million payment from USEB Settlement Approved

(London, Ontario, January 18, 2007) – Countryside Power Income Fund (TSX: COU.UN) (the "Fund") today announced that it confirms its previously declared distribution of $0.0860 per unit payable on January 31, 2007, to unitholders of record as of December 29, 2006.

The Fund confirms the December 2006 distribution following yesterday's approval by the United States Bankruptcy Court in the Southern District of New York (the "U.S. Bankruptcy Court") of a US$3-million payment to be made on or before January 31, 2007, by U.S. Energy Biogas Corp. ("USEB") to the Fund. The Fund also has received permission from its syndicate of lenders to make the distribution to unitholders. Along with the approved payment from USEB, the U.S. Bankruptcy Court has set February 1, 2007, as the hearing date to make a final ruling on the settlement agreement reached, through mediation, among the Fund's subsidiary, Countryside Canada Power Inc. (the "Lender"), USEB and its parent, U.S. Energy Systems, Inc., on January 13, 2007, that seeks to resolve all outstanding issues between the parties ("USEB Settlement Agreement") -- as disclosed in a press release dated January 15, 2007. In addition to U.S. Bankruptcy Court approval, the USEB Settlement Agreement is also subject to approval by the Fund's syndicate of lenders. The respective boards have approved the USEB Settlement Agreement.

"We are encouraged by the swift progress that has been made to recoup our investment in USEB," said Göran Mörnhed, President and Chief Executive Officer of Countryside Ventures LLC. " As we move forward, we will look to expedite the monetization of our secured claim and make a decision on the resulting use of proceeds in the best interest of unitholders."

The Fund is currently in discussions with its lenders regarding an extension of its existing waiver. The objective is to have the USEB Settlement Agreement reflected in a long-term financing solution that will provide the Fund with greater financial flexibility to support ongoing distributions and to meet its growth commitments, including the construction of the new London cogeneration facility scheduled to be completed in 2008. There can be no assurance as to the outcome of these discussions with the lenders.

2006 United States Income Tax Information

After consultation with its U.S. tax advisors, the Fund believes that its units more likely than not will be properly classified as equity in a corporation, rather than debt, for U.S. federal income tax purposes, and that distributions paid to its individual U.S. unitholders will more likely than not be qualified dividends. As such, the portion of the distributions made during 2006 that are considered dividends should qualify for the reduced rate of tax applicable to certain capital gains. This tax information applies to U.S. resident taxpayers only and has no impact on Canadian resident taxpayers. For more information concerning this matter please refer to the Fund's website at www.countrysidepowerfund.com and access Tax Information on "The Fund" page.

Forward-Looking Statements

This press release may contain forward-looking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time to time in the Fund's annual information form dated March 31, 2006, and available on SEDAR. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

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Further information:

Andrew Kondraski
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BarnesMcInerney Inc.
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Nicole Archibald
Vice President, Administration
Countryside Canada Ventures Inc.
Tel: 519-435-0298
info@countrysidepowerfund.com

NOT FOR DISTRIBUTION IN THE UNITED STATES OR OVER
UNITED STATES WIRE SERVICES

COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund Announces U.S. Court Approval of USEB Settlement

Fund declares January 2007 distribution

(London, Ontario, February 1, 2007) – Countryside Power Income Fund (TSX: COU.UN) (the "Fund") today announced that The United States Bankruptcy Court in the Southern District of New York ("U.S. Court") has held a hearing and stated it will approve the previously disclosed settlement among the Fund's subsidiary, Countryside Canada Power Inc. (the "Lender"), U.S. Energy Biogas Corp. ("USEB") and its parent, U.S. Energy Systems, Inc subject to its review and approval of the final documentation (the "USEB Settlement").

USEB Settlement

The USEB Settlement, provides, among other things, for the Lender to have an allowed secured claim of US$99,000,000 (approximately CAD$116,500,000 at the current exchange rate) inclusive of all principal, pre- and post-petition interest, charges, premiums, penalties, make-whole amounts, attorneys' fees and expenses and expert fees and expenses accrued or incurred by the Lender through and including January 31, 2007, secured by all the liens and security interests and other rights granted under the USEB loan documents.

The outstanding principal amount of the allowed secured claim had been reduced to US$96,000,000 from receipt of a US$3,000,000 payment from USEB as at January 31, 2007, in accordance with a U.S. Court order entered on January 17, 2007. Further, the outstanding amounts of the allowed secured claim shall be deemed over secured for purposes of adequate protection and the use of cash collateral in the USEB bankruptcy cases and shall bear cash interest at a rate of 10% per annum commencing February 1, 2007, payable monthly in U.S dollars to the Lender.

The USEB Settlement also provides for installment cash payments of US$30,000,000 on or before March 31, 2007, and the remaining balance on or before maturity at May 31, 2007. The parties will work together to pursue a "take-out" financing before the final installment date of May 31, 2007. Mutual general releases will be exchanged among the parties involved and will cover individuals affiliated with the Fund who have been threatened with lawsuits arising out of their prior employment by USEY. USEB filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code on November 29, 2006.

The USEB Settlement shall become effective when the approval order has been entered by the Bankruptcy Court which is expected shortly and either (i) has become a final and non-appealable order under applicable law or (ii) has become effective in accordance with its terms or Federal Rules of Bankruptcy Procedure 6004(h) and 7062 and Federal Rule of Civil Procedure 62(a), whichever is earliest, and no stay pending appeal of such order has been entered and is effective.

January 2007 Distribution

The Fund also declared that its January 2007 distribution of $0.8630 per unit will be paid on February 28, 2007, to unitholders of record as at February 8, 2007. The Fund's policy is for unitholders of record on the last business day of a calendar month to receive distributions on or about the 30th day of the following month. Holders of units who are non-residents of Canada will be required to pay all applicable withholding taxes payable in respect of any distributions by the Fund.

The Fund also closed on its waiver and amendment to its existing credit facility agreement with its lending sydicate on January 30, 2007 which provides for, among other things, permission to make unitholder distributions through the four month waiver period, ending May 31, 2007, subject to ongoing compliance with financial covenants.

Forward-Looking Statements

This press release may contain forward-looking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time to time in the Fund's annual information form dated March 31, 2006, and available on SEDAR. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

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Further information:

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COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund Announces Review of Strategic Alternatives and Retention of Financial Advisor

Fund Amends Management Agreement in Connection with Bank Waiver

(London, Ontario, February 9, 2007) Countryside Power Income Fund (TSX: COU.UN) together with its subsidiaries, (collectively the "Fund") announced today that the board of trustees has engaged Lehman Brothers Inc. to assist the board of trustees with its ongoing process of identifying and considering strategic alternatives available to the Fund to maximize unitholder value. The Fund also announced today an amendment to the management agreement dated September 23, 2005, between subsidiaries of the Fund and Countryside Ventures LLC (the "Manager") (and collectively the "Management Agreement") resulting from the waiver and amendment recently granted by its syndicate of lenders.

Review of Strategic Alternatives

The strategic review process has been advanced and formalized in response to: (i) the expected impact to the Fund of the recent ruling by the US Bankruptcy Court indicating that it is prepared to enter an order approving the U.S. Energy Biogas Corp. ("USEB") settlement (see press release dated February 2, 2007) and (ii) the Canadian government's proposed legislation to tax income trusts. The strategic review process is intended to consider a range of value enhancement alternatives that will involve a comprehensive review of the Fund's existing capital structure, growth strategy, and access to capital markets as well as prospects as an income trust. The process will also consider such alternatives as a sale of the Fund (or its segments), a conversion to a corporate structure, and/or a recapitalization. As part of the process, the Fund will consider the best use of proceeds for the expected cash monetization of its remaining US$96 million (CAD$113 million) secured claim in USEB. The Fund expects to conclude its strategic review process by the end of March 2007. There can be no assurance that the evaluation process will result in a decision regarding any transaction or that it will be completed in the specified time frame.

Amendment to Management Agreement

As of January 25, 2007, the Fund's lending syndicate approved, among other things, an extension of the prior waiver of the cross-default provisions of the credit agreement to May 31, 2007. In consideration for the waiver extension, the Fund was required to pledge the Ripon-related assets, and the Manager was required to waive certain existing rights with respect to the Manager's 25% subordinated interest in Ripon Power LLC, which was originally provided as consideration to the Manager in connection with the origination and acquisition of Ripon in 2005 (the "Manager's Subordinated Interest"). The Fund holds the remaining 75% of the subordinated interest in Ripon Power LLC. At the time of the waiver and in order to accommodate the lending syndicate's requirement, the board of trustees of the Fund entered into an agreement with the Manager to purchase, on June 29, 2007 (or before in certain circumstances), 85% of the Manager's Subordinated Interest for cash and Fund units equal to $16,026,111 based on a unit price of $8.32. Under the prior arrangement, the Manager's Subordinated Interest could be exchanged for units of the Fund on or after June 29, 2007 (or before in certain circumstances) at the option of either the Fund or the Manager (subject to regulatory approval). The consideration to be paid will comprise a minimum of 10% cash and will provide the Fund with an option to increase the cash component up to 25% of the total consideration if the board of trustees deems such payment to be economically beneficial to the Fund.

After completion of the purchase of the 85% of the Manager's Subordinated Interest, the Manager will hold 3.75% and the Fund will hold 96.25%, respectively, of the subordinated interest in Ripon Power LLC. The board of trustees believes that the retained Manager's Subordinated Interest will help ensure a continued focus by the Manager on potential Ripon-related growth opportunities. As part of its decision to enter into this agreement, the board of trustees sought and received an opinion as to the fairness of the consideration to be paid in connection with the amendment to the Management Agreement.

Forward-Looking Statements

This press release may contain forward-looking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time to time in the Fund's annual information form dated March 31, 2006, and available on SEDAR. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

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COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund Declares February Distribution

(London, Ontario, February 28, 2007) – Countryside Power Income Fund (TSX: COU.UN) (the "Fund") announced that its February 2007 distribution of $0.0863 per unit will be paid on March 30, 2007, to unitholders of record as at March 8, 2007. Holders of units who are non-residents of Canada will be required to pay all applicable withholding taxes payable in respect of any distributions by the Fund.

Forward-Looking Statements
This press release may contain forward-looking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time to time in the Fund's annual information form dated March 31, 2006, and available on SEDAR. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

About Countryside Power Income Fund
Countryside Power Income Fund has investments in two district energy systems in Canada, with a combined thermal and electric generation capacity of approximately 122 megawatts, and two gas-fired cogeneration plants in California, with a combined power generation capacity of 94 megawatts. More information about the Fund is available at www.countrysidepowerfund.com

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COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund to Hold Fourth Quarter and Year End Conference Call

(London, Ontario, March 14, 2007) -- Countryside Power Income Fund (TSX: COU.UN) today announced it will hold a conference call and live audio webcast on **Tuesday, March 27, 2007, at 10 a.m. (ET)** to discuss the Fund's financial results for the quarter and year ended December 31, 2006.

A news release announcing the Fund's results will be issued prior to the call.

The call will be hosted by Göran Mörnhed, President and Chief Executive Officer of Countryside Ventures LLC, and Edward M. Campana, Executive Vice-President and Chief Financial Officer of Countryside Ventures LLC. Following management's presentation, there will be a question and answer session for analysts and institutional investors.

To participate in the teleconference, please dial **416-644-3417** or **1-800-733-7560.** To access the live audio webcast, please visit Countryside's web site at www.countrysidepowerfund.com. The webcast will also be archived on the web site.

About Countryside
Countryside Power Income Fund has investments in two district energy systems in Canada, with a combined thermal and electric generation capacity of approximately 122 megawatts, and two gas-fired cogeneration plants in California with a combined power generation capacity of 94 megawatts. More information on the Fund is available at www.countrysidepowerfund.com.

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Further information:

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COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund Declares March Distribution

(London, Ontario, March 21, 2007) – Countryside Power Income Fund (TSX: COU.UN) (the "Fund") announced that its March 2007 distribution of $0.0863 per unit will be paid on April 30, 2007, to unitholders of record as at March 30, 2007. Holders of units who are non-residents of Canada will be required to pay all applicable withholding taxes payable in respect of any distributions by the Fund.

Forward-Looking Statements

This press release may contain forward-looking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time to time in the Fund's annual information form dated March 31, 2006, and available on SEDAR. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

About Countryside Power Income Fund

Countryside Power Income Fund has investments in two district energy systems in Canada, with a combined thermal and electric generation capacity of approximately 122 megawatts, and two gas-fired cogeneration plants in California, with a combined power generation capacity of 94 megawatts. More information about the Fund is available at www.countrysidepowerfund.com

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FORM 13-502F1
CLASS 1 REPORTING ISSUERS – PARTICIPATION FEE

Reporting Issuer Name: Countryside Power Income Fund

Financial Year Ending used to calculate capitalization: December 31, 2006

Market value of listed or quoted securities:
Total number of securities of a class or series outstanding as at the issuer's most recent financial year end — 20,812,097

Simple average of the closing price of that class or series as of the last trading day of each month of the fiscal year (See clauses 2.11(a)(ii)(A) and (B) of the Rule) — 9.20

Market value of class or series — (i) X (ii) = 191,471,292(A)

(Repeat the above calculation for each class or series of securities of the reporting issuer that was listed or quoted on a marketplace in Canada or the United States of America at the end of the fiscal year) — (B)

Market value of other securities:
(See paragraph 2.11(b) of the Rule)
(Provide details of how value was determined) — 49,406,620(C)
(Debentures outstanding times the market value at end of year times year-end fx spot rate)

(Repeat for each class or series of securities) — (D)

Capitalization
(Add market value of all classes and series of securities) — (A)+(B)+(C) +(D) = 240,877,912

Participation Fee — **6,700**
(From Appendix A of the Rule, select the participation fee beside the capitalization calculated above)

New reporting issuer's reduced participation fee, if applicable
(See section 2.6 of the Rule)

Participation fee	X	Number of entire months remaining in the issuer's fiscal year	=	
	12			

Late Fee, if applicable
(As determined under section 2.5 of the Rule)

ANNUAL CERTIFICATE
PURSUANT TO SECTIONS 3.1 AND 3.4 OF NATIONAL POLICY 41-201

COUNTRYSIDE POWER INCOME FUND

TO: Ontario Securities Commission
Alberta Securities Commission
British Columbia Securities Commission
Manitoba Securities Commission
New Brunswick Securities Commission
Nova Scotia Securities Commission
Financial Services Regulation Division
Registrar of Securities, Prince Edward Island
Autorité des marchés financiers
Saskatchewan Financial Services Commission
Registrar of Securities, Government of Yukon Territory
Securities Registry, Government of the Northwest Territories
Registrar of Securities, Nunavut
(collectively, the **"Securities Commissions"**)

COUNTRYSIDE POWER INCOME FUND (the **"Fund"**) has undertaken that in complying with the Fund's reporting issuer obligations, it will treat **RIPON POWER LLC ("Ripon")** as a subsidiary of the Fund; provided, however, that if generally accepted accounting principles prohibit the consolidation of financial information of Ripon and the Fund, for as long as Ripon (including any of its significant business interests) represents a significant asset of the Fund, the Fund will provide unitholders with separate financial statements for Ripon (including information about any of its significant business interest).

The Fund has taken appropriate measures to require each person who would be an insider of Ripon if Ripon were a reporting issuer to (a) file insider reports about trades in trust units of the Fund (including securities which are exchangeable into trust units of the Fund), and (b) comply with statutory prohibitions against insider trading.

The Fund hereby certifies that, in respect of the year ended December 31, 2006, it has complied with the undertaking set out above.

DATED this 26th day of March 2007.

COUNTRYSIDE POWER INCOME FUND

Per: *"Nicole Archibald"*

Name: Nicole Archibald
Title: VP - Administration

AUDITORS' REPORT

To the Unitholders of
Countryside Power Income Fund

We have audited the consolidated balance sheets of **Countryside Power Income Fund** as at December 31, 2006 and 2005 and the consolidated statements of income and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Manager of the Fund. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2006 and 2005, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

"Ernst & Young LLP"

London, Canada,
March 23, 2007.

Chartered Accountants

CONSOLIDATED BALANCE SHEETS

[in thousands of Canadian dollars]

As at December 31	2006 $	2005 (as restated – note 3) $
ASSETS		
Current		
Cash and cash equivalents	8,430	10,312
Accounts receivable *[note 15]*	14,811	13,025
Inventories *[note 7]*	1,222	1,310
Prepaid expenses	1,499	1,226
U.S. Energy Biogas Corp. receivable *[note 8]*	113,968	-
Future income tax asset *[note 13]*	810	1,296
Current portion of loans receivable from U.S. Energy Biogas Corp. *[note 8]*	-	2,040
Total current assets	140,740	29,209
Loans receivable from U.S. Energy Biogas Corp. *[note 8(a)]*	-	101,921
Royalty interest in U.S. Energy Biogas Corp., net *[note8(b)]*	-	7,194
Other assets *[note 9]*	3,576	6,894
Property, plant and equipment, net *[note 10]*	71,357	72,807
Other intangibles, net *[note 11]*	69,125	75,078
Future income tax asset *[note 13]*	1,393	-
Total assets	286,191	293,103
LIABILITIES AND UNITHOLDERS' EQUITY		
Current		
Bank indebtedness *[note 12]*	674	1,615
Accounts payable and accrued liabilities	13,683	7,909
Distribution payable to unitholders *[note 18]*	1,790	1,694
Current portion of long-term debt *[note 12]*	48,500	-
Total current liabilities	64,647	11,218
Long-term debt *[note 12]*	-	47,500
Debentures – liability component *[note 6]*	50,308	62,295
Other long-term liabilities	243	3,362
Future income tax liability *[note 13]*	802	1,676
Total liabilities	116,000	126,051
Commitments and contingencies [note 16]		
Unitholders' equity		
Trust units *[notes 6 & 14]*	188,918	177,505
Debentures – equity component *[note 6]*	1,377	1,715
Deficit	(16,431)	(8,497)
Cumulative translation adjustment	(3,673)	(3,671)
Total unitholders' equity	170,191	167,052
Total liabilities and unitholders' equity	286,191	293,103

See accompanying notes

Approved on behalf of Countryside Power Income Fund:

"*V. James Sardo*" "*James R. Anderson*"

V. James Sardo
Chairman of the Board
Countryside Power Income Fund

James R. Anderson
Trustee
Countryside Power Income Fund

CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT

[in thousands of Canadian dollars, except per trust unit amounts]

	2006	2005 (as restated – note 3)
For the year ended December 31,	**$**	**$**
REVENUES		
Energy sales	78,071	52,823
Fuel and other fees	1,991	2,252
Interest income on loans to U.S. Energy Biogas Corp. *[note 8]*	11,517	11,546
Income from U.S. Energy Biogas Corp. royalty interest *[note 8]*	350	369
Other income	528	171
	92,457	67,161
EXPENSES		
Fuel, operating and maintenance	53,017	34,898
General and administration *[note 21]*	9,150	10,949
Amortization	11,948	8,061
	74,115	53,908
Operating income	**18,342**	**13,253**
Interest expense *[note 12]*	7,104	5,578
Loss (gain) on derivative instruments *[note 12]*	148	(2,871)
Foreign exchange gain *[note 9]*	(373)	(750)
	6,879	1,957
Income before (recovery of) provision for income taxes	**11,463**	**11,296**
(Recovery of) provision for income taxes *[note 13]*		
Current	438	22
Future	(1,779)	30
	(1,341)	52
Net income for the year	**12,804**	**11,244**
Deficit, beginning of year as previously reported	(6,580)	(3,596)
Subordinated Interest adjustment *[note 3]*	(1,917)	-
Deficit, as restated	(8,497)	-
Distributions declared to Unitholders *[note 18]*	(20,738)	(16,145)
Deficit, end of year	**(16,431)**	**(8,497)**
Net income per trust unit – basic *[note 14]*	**0.64**	**0.72**
Net income per trust unit – diluted *[note 14]*	**0.64**	**0.72**

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS

[in thousands of Canadian dollars]

For the year ended December 31,	2006 $	2005 (as restated – note 3) $
OPERATING ACTIVITIES		
Net income for the year	12,804	11,244
Add (deduct) items not involving cash		
Amortization	11,177	7,221
Amortization of deferred financing charges	771	840
Loss (gain) on derivative instruments *[notes 9 & 12]*	148	(2,871)
(Recovery of) provision for future income taxes *[note 13]*	(1,779)	30
Unrealized gain on foreign exchange	(358)	(750)
USEB royalty interest accrual	(350)	-
Subordinated Interest adjustment *[note 3]*	-	3,196
Accreted interest on Debentures *[note 6]*	176	24
	22,589	18,934
Net change in non-cash working capital balances related to operations		
Accounts receivable	(3,823)	(1,682)
Inventories	88	(256)
Prepaid expenses	(273)	(1,139)
Accounts payable and accrued liabilities	1,849	915
Cash provided by operating activities	20,430	16,772
INVESTING ACTIVITIES		
Acquisition of Ripon Power LLC *[note 5]*	-	(42,803)
Repayment of loans receivable from U.S. Energy Biogas Corp. *[note 8]*	1,684	1,828
Purchase of property, plant and equipment	(3,399)	(855)
Cash used in investing activities	(1,715)	(41,830)
FINANCING ACTIVITIES		
Acquisition of loan and working capital revolver from Union Bank of California	-	(70,490)
Issuance of Debentures *[note 6]*	-	64,180
Deferred financing charges on Debentures *[notes 6]*	-	(3,922)
Acquisition of foreign exchange option contract *[note 16]*	-	(219)
Payment of swap breakage fee	-	(496)
Proceeds from Amended Credit Facility *[note 12]*	1,000	48,000
Repayment of Amended Credit Facility *[note 12]*	-	(30,500)
(Repayment of) proceeds from swing line credit facility *[note 12]*	(941)	1,615
Deferred financing charges on Amended Credit Facility *[note 12]*	-	(1,001)
Repayment of obligations under capital lease	(48)	(31)
Distributions paid to Unitholders *[note 18]*	(20,642)	(15,725)
Issuance of trust units on Offering *[notes 6 & 14]*	-	44,132
Expenses of Offering *[notes 6 & 14]*	-	(2,977)
Cash (used in) provided by financing activities	(20,631)	32,566
Effect of exchange rate changes on cash and cash equivalents	34	(231)
Net (decrease) increase in cash during the year	(1,882)	7,277
Cash and cash equivalents, beginning of the year	10,312	3,035
Cash and cash equivalents, end of the year	8,430	10,312
Supplemental cash flow information		
Interest paid	6,584	6,235
Income taxes paid	442	5

See accompanying notes

NOTE 1 – DESCRIPTION OF BUSINESS

Countryside Power Income Fund (the "Fund") is an unincorporated, open-ended, limited purpose trust established under the laws of the Province of Ontario on February 16, 2004. The Declaration of Trust was amended and restated on April 8, 2004, the date of the initial public offering of trust units of the Fund (the "Initial Offering"). The Fund owns 100% of Countryside Canada Power Inc. ("Countryside Canada").

The Fund holds through its indirect subsidiary Countryside District Energy Corp. ("Countryside District Energy") the district energy systems located in Charlottetown, Prince Edward Island (the "PEI System") and London, Ontario, (the "London System"), (collectively the "District Energy Systems"). In addition, the Fund has an indirect investment in 22 renewable power and energy projects located in the United States. The Fund's investment in the projects consists of a receivable from U.S. Energy Biogas Corp. ("USEB") (see note 8). Additionally, on June 29, 2005, the Fund completed the acquisition of the membership interests of Ripon Power LLC ("Ripon Power") (formerly known as Lightyear Rockland Partners LLC) whose principal assets are two gas-fired cogeneration facilities located in California (the "Cogen Facilities").

The Fund is managed by Countryside Ventures LLC ("Countryside Ventures" or the "Manager") which provides management and administrative services to Countryside Canada and Countryside US Holding Corp. ("Countryside US Holding") as well as new growth opportunities under long-term agreements.

NOTE 2 – SIGNIFICANT ACCOUNTING POLICIES

The accompanying comparative consolidated financial statements of the Fund have been prepared by management within reasonable limits of materiality using Canadian generally accepted accounting principles ("GAAP") and within the framework of the significant accounting policies summarized below.

(a) Basis of Presentation

The results of Ripon Power's operations have been reflected in the comparative consolidated financial statements of the Fund beginning on June 30, 2005, the date of its acquisition by the Fund.

(b) Basis of Consolidation

The consolidated financial statements of the Fund include the accounts of its wholly-owned subsidiary, Countryside Canada, and the accounts of Countryside Canada's direct and indirect subsidiary entities including Countryside US Holding, Countryside U.S. Power Inc. (Countryside U.S. Power), Ripon Power, Ripon Cogeneration LLC ("Ripon Cogen"), Countryside District Energy and Countryside London Cogeneration Corp. ("Countryside London Cogen"). Countryside District Energy is the legal entity that holds the District Energy Systems. All inter-entity transactions and balances have been eliminated on consolidation.

(c) Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires the Fund to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results will differ from those estimates.

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

(d) Cash and Equivalents

Cash and cash equivalents comprise only highly liquid investments with remaining maturities of 90 days or less and are recorded at cost, which approximates market value.

(e) Inventories

Inventories of spare and replacement parts and supplies are valued at the lower of cost, on a first-in, first-out basis, and net replacement value. Fuel, consisting primarily of natural gas, wood chips and oil, is carried at the lower of cost, as determined on a weighted average basis, and net realizable value.

(f) Royalty Interest in U.S. Energy Biogas Corp.

The Royalty Interest in USEB was being amortized on a straight-line basis over 20 years [note 8].

(g) Property, Plant and Equipment

Capital assets are accounted for at their acquisition cost. Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. The cost of the property, plant and equipment, less estimated residual value, is amortized on a straight-line basis over the estimated useful lives of the assets as follows:

	Years
Buildings	21-35
Equipment	
Plant and distribution	1-35
Computers	3-5
Office	3-5
Vehicles	5
Equipment under capital lease	20

Assets included in construction in progress are not amortized until the installation of the assets is complete and the assets have entered into commercial operation.

(h) Other Intangibles

The fair values at the date of acquisition of the District Energy Systems' customer relationships are being amortized on a straight-line basis over 21 years [note 11]. The fair values of the power purchase agreements at the date of acquisition of the Cogen Facilities are being amortized on a straight-line basis over their remaining lives at the time of their acquisition, of between 10 and 12.5 years [note 11].

(i) Foreign Currency Translation

The assets and liabilities of the Fund's US subsidiaries having a functional currency of US dollars are translated into Canadian dollars using the exchange rate in effect at the year end, and revenues and expenses are translated at the average rate during the year. Exchange gains or losses on translation of the Fund's net investment in these operations are recorded as a separate component of Unitholders' Equity.

(j) Financial Instruments

The Fund uses an interest rate swap contract to manage interest rate risk. Payments and receipts under the interest rate swap contract are recognized as adjustments to interest expense on an accrual basis. Any resulting carrying amounts are included in other assets in the case of favourable contracts and accounts payable and accrued liabilities in the case of unfavourable contracts (notes 9 & 12).

Realized gains and losses on interest rate swaps are reported as a component of consolidated interest expense. The change in fair value of the interest rate swaps are recorded as a component of loss (gain) on derivative instruments on the statements of income and recorded as a non-current asset or liability.

The Fund has entered into call option contracts to manage its foreign exchange exposure resulting from foreign exchange fluctuations. The fair value of the foreign exchange option contracts are recorded in other assets in the case of favourable contracts or accounts payable and accrued liabilities in the case of unfavourable contracts at the end of each reporting period [note 9].

The above derivative financial instruments represent economic hedges of known exposures; however they do not qualify for hedge accounting and therefore have been recorded at their fair value in the consolidated financial statements.

The Fund does not engage in trading or other speculative activities with respect to derivative financial instruments. The fair value of derivative financial instruments reflects the estimated amount that the Fund would have been required to pay if forced to settle all unfavourable contracts or the amount that would be received if the Fund were forced to settle all favourable contracts at year end. The fair value represents a point-in-time estimate that may not be relevant in predicting the Fund's future earnings or cash flows.

The Fund is exposed to credit risk in the event of non-performance by its counterparties. The Fund does not anticipate non-performance, as the counterparty to both the interest rate swap and the call option have investment grade credit ratings.

(k) Deferred Financing Charges

Deferred financing charges represent fees incurred related to bank financing and debenture issuances and are being amortized on a straight-line basis over the life of the respective instruments [note 9].

(l) Loan Origination Fees

Loan origination fees represent costs incurred related to the USEB Loans (as defined in the USEB Loan Agreement). Until December of 2006, these costs were being amortized on a straight-line basis over 15 years [note 8].

(m) Subordinated Interest

The Subordinated Interest is recorded as a liability and will be marked to market beginning in the second quarter of 2007 in accordance with the Operating Agreement as outlined in note 21.

(n) Revenue Recognition

Revenue derived from the sale of energy in the form of electricity, steam, hot water and chilled water is recognized on the accrual basis upon delivery at rates pursuant to the relevant energy service agreements ("ESAs") with the purchasing customers. In addition to the sale of energy under the ESAs, the Fund receives from the purchasing customers monthly capacity payments that are fixed and are not dependent upon the amount of energy delivered to its customers. This revenue is recognized as earned on a monthly basis. Income earned from receipt of waste fuel for the PEI System is based on long-term contracts and is recognized upon receipt of the waste fuel at the PEI System. Interest income from the USEB Loans and the USEB Royalty Interest is recognized as earned.

(n) Income Taxes

Future income taxes and liabilities are recognized for the future income tax consequences attributable to differences between the tax and accounting bases of assets and liabilities, as well as for the benefit of tax losses available to be carried forward to future years that are more likely than not to be realized. The differences are measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

To the extent that the Fund's taxable income and taxable capital gains are paid or payable to Unitholders, under the terms of the *Income Tax Act (Canada)*, the Fund, excluding its corporate subsidiaries, is not subject to income taxes. In addition, as the Fund is contractually committed to distribute to Unitholders all or virtually all of its taxable income and taxable capital gains that would otherwise be taxable to the Fund, the Fund is not required to apply the recommendations of the Canadian Institute of Chartered Accountants Handbook ("CICA"), section 3465. Accordingly, no provision for current income taxes for the Fund is made. Distributions may however be taxable in the hands of Unitholders.

Each of the Fund's Canadian subsidiaries is subject to corporate income and capital taxes as computed under the *Income Tax Act (Canada)* and relevant provincial tax legislation and to CICA Handbook section 3465. Each of the Funds' U.S. subsidiaries are subject to corporate and state revenue and franchise taxes as well as withholding tax on interest and dividends paid to Canadian corporations. A valuation allowance is provided to the extent that it is more likely than not that future income tax assets will not be realized.

(o) Net Income per trust unit

Net income per trust unit is based on the consolidated net income for the period, divided by the weighted average number of trust units outstanding during the year which was 19,968,697 (2005 – 15,513,147). Diluted net income per trust unit is calculated by dividing consolidated net income, plus interest expense relative to the debt that would be exchanged by the weighted average number of trust units used in the basic net income per trust unit calculation plus the number of trust units that would be issued assuming conversion of the exchangeable unsecured subordinated debentures into trust units of the Fund. For the purposes of the weighted average number of trust units calculation, trust units are determined to be outstanding from the date they are issued. Diluted income per trust unit is not calculated when the impact of the trust units issued on the exchange of the exchangeable unsecured subordinated debentures would be anti-dilutive.

NOTE 3 – ACCOUNTING FOR SUBORDINATED INTEREST

In March 2007, the Fund assessed the initial accounting for the granting of the Manager's Subordinated Interest in Ripon Power (see note 21), and determined that compensation expense consisting of the fair value of the Subordinated Interest at the time of the grant was required to be recorded in the third quarter of 2005, which represented the period in which the Subordinated Interest was granted. As a result of the Manager's option to exchange its Subordinated Interest for a variable number of units of the Fund, the Subordinated Interest is required to be classified as a liability in the Fund's consolidated financial statements. Accordingly, for the year ended December 31, 2005, general and administration expenses have been increased by $3,196, the provision for future income taxes has been reduced by $1,279, net income has been reduced by $1,917, closing deficit has been increased by $1,917, future income tax assets have been increased by $1,211, other long-term liabilities have been increased by $3,026 and the cumulative translation adjustment has been reduced by $102. Earnings per trust unit have been reduced by $0.13.

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

For the year ended December 31, 2006, the liability associated with the Subordinated Interest in the amount of $3,032 has been included in current liabilities as a component of accounts payable and accrued charges, in connection with the Fund's agreement to purchase 85% of the Manager's Subordinated Interest in June 2007.

NOTE 4 – SEASONALITY

The Cogen Facilities' results are affected by seasonality with sales and operating income that are typically greater during the second and third quarters and are typically lower during the winter season (the first and fourth quarters) when electrical capacity revenues are lower.

The District Energy Systems' energy sales volumes including steam, hot water and chilled water are seasonal, with higher demand occurring during the winter heating season and typically lower demand occurring during the summer and fall.

On a combined basis the impact of the Cogen Facilities' seasonal sales are more dominant, typically resulting in higher revenues and Adjusted EBITDA (defined in note 20 below) during the second and third quarters.

To adjust for seasonality, the Fund follows a practice of declaring equal monthly distributions to unitholders during the year through the use of cash reserves.

NOTE 5 – ACQUISITION OF RIPON POWER

The Fund's investment in Ripon Power, effective June 29, 2005 was made through its wholly-owned subsidiary, Countryside US Holding. Financing for the transaction was provided through an amendment to the Fund's Credit Facility (see note 12). The acquisition was accounted for using the purchase method. The purchase price was satisfied through cash consideration of approximately $44,000 [US $35,800], plus approximately $1,100 of transaction costs.

The purchase price was allocated, in Canadian dollars, as follows:

	Amount **$**
Working capital, including cash of $2,269	4,823
Property, plant and equipment	46,933
Power purchase agreements	69,510
Other long term liability	(3,122)
Long-term debt	(73,072)
	45,072

NOTE 6 – TRUST UNIT AND EXCHANGEABLE DEBENTURE OFFERING

Trust Unit and Exchangeable Debenture Offering (the "Offering")

On November 14, 2005, the Fund and Countryside Canada closed an offering of 4,720,000 trust units at $9.35 per unit for gross proceeds of $44,132 and $64,180 [US $55,000] aggregate principal amount of 6.25% U.S. dollar denominated exchangeable unsecured subordinated debentures ("Debentures"), due October 31, 2012 (the "Maturity Date"). The trust units were issued by the Fund and the Debentures were issued by Countryside Canada. Net proceeds of the Offering were approximately $101,413 and were used to repay indebtedness under the Fund's revolving credit facility associated with the acquisition of Ripon Power, to acquire the long-term debt and working capital revolver of the Cogen Facilities and to pay transaction costs of the Offering with the excess remaining proceeds used for working capital purposes.

Debentures

Interest is paid in US dollars, semi-annually in arrears on April 30 and October 31 of each year. The payment of Debenture principal and interest is subordinated in right of payment to the prior payment of all senior indebtedness of the Fund.

Each Debenture is exchangeable for Units at the option of the holder at any time prior to the close of business on the earlier of the Maturity Date and the business day immediately preceding the date specified by Countryside Canada for redemption of the Debentures, at an exchange price of $10.75 per Unit (the "Exchange Price") being a ratio of 109.4884 Units per one thousand US dollars in principal amount of Debentures, subject to adjustment in certain events in accordance with the trust indenture governing the terms of the Debentures. Holders exchanging their Debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their Debentures to the date of exchange. Notwithstanding the foregoing, no Debentures may be exchanged during the five business days preceding April 30 and October 31 in each year as the registers of the Debenture Trustee will be closed during such periods.

During 2006, US $10,839 Debentures were exchanged into 1,186,731 trust units, resulting in the principal amount of Debentures outstanding at December 31, 2006 of US $44,161.

The Debentures may not be redeemed by Countryside Canada on or prior to October 31, 2008, except in the event of the satisfaction of certain conditions after a Change of Control has occurred. Thereafter, but prior to October 31, 2010, the Debentures may be redeemed, in whole or in part, at a price equal to the principal amount thereof plus accrued and unpaid interest on not more than 60 days' and not less than 30 days' prior notice, provided that the weighted-average trading price of the Units on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given is not less than 125% of the Exchange Price. On or after October 31, 2010 and prior to the Maturity Date, the Debentures may be redeemed by Countryside Canada, in whole or in part, at a price equal to the principal amount thereof plus accrued and unpaid interest on not more than 60 days' and not less than 30 days' prior written notice.

Subject to regulatory approval, Countryside Canada may, at its option, elect to satisfy its obligation to pay the principal amount of the Debentures on redemption or at maturity through, in whole or in part, the delivery of freely-tradeable Units. The Fund will take all actions and do all things necessary or desirable to enable and permit Countryside Canada, in accordance with applicable law, to perform its obligations to deliver the requisite number of Units to the extent holders exercise their exchange right.

The Fund performed a valuation of the embedded holder option on the Debentures and determined that its value on November 14, 2005 was $1,715. Such portion of the value of the Debentures has been recorded as a component of unitholders' equity. The liability component of the Debentures will be accreted to the face value of the Debentures over the term to maturity and accretion for the period will be included in interest expense in the consolidated statements of income (for the year ended December 31, 2006 - $176, 2005 - $24).

NOTE 7 – INVENTORIES

Inventories consist of the following:

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

	2006 $	2005 $
Spare parts	831	822
Fuel	391	488
	1,222	**1,310**

NOTE 8 – U.S. ENERGY BIOGAS CORP. RECEIVABLE

On November 29, 2006, USEB and various subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York.

Through mediation, the Fund, the Manager (including its members, individually), U.S. Energy Systems, Inc. ("USEY"), and USEB reached agreement in principle on January 13, 2007. The USEB settlement was approved by the Bankruptcy Court in principle on February 1, 2007 and formalized in (i) a settlement agreement by and among the parties ("Parties") (the "USEB Settlement Agreement") and (ii) a stipulation and final order authorizing USEB to use certain cash collateral and granting adequate protection payments in the form of cash interest to the Fund (the "Final Cash Collateral Order"). The Settlement Agreement and Final Cash Collateral Order were formally approved by order of the Bankruptcy Court on February 16, 2007 (collectively the "Approval Order"). The Approval Order became final and non-appealable on February 26, 2007 and the Settlement Agreement became effective on March 7, 2007.

The USEB Settlement Agreement settles Countryside Canada's claims for all amounts claimed under the USEB Loans (including, without limitation, principal, pre and post-petition interest, loan breakage fees, expenses and indemnity) and the Development Agreement among USEY, Countryside US Power and an indirect subsidiary of Cinergy (see note 17) by allowance of a secured claim against USEB and its debtor affiliates of US$99,000 ($115,375 at the year end exchange rate) in the USEB Bankruptcy (the "Allowed Secured Claim"). The Allowed Secured Claim continues to be secured by a first lien on substantially all of the assets of USEB and its subsidiaries, which may be enforced through the enforcement remedies provided in the USEB Loan.

The USEB Settlement Agreement provides for installment cash payments on the Allowed Secured Claim of US$3,000 on or before January 31, 2007 (which was received in cash on January 31, 2007), US$30,000 on or before March 31, 2007 (which was received in cash over a period from March 9 -13, 2007), and the remaining principal balance and accrued unpaid interest on or before maturity at May 31, 2007. USEB may pay up to US$2,000 in USEY common stock which is registered or otherwise freely tradable with the number of shares to be calculated based on the weighted average closing price on the five trading days preceding the payment.

Outstanding principal balances under the Allowed Secured Claim bear cash interest at a rate of 10% per annum from February 1, 2007, payable monthly in U.S. dollars.

The following table illustrates the consolidation of all of the Fund's balance sheet amounts as at December 31, 2006, related to its investments in USEB.

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

	Amount $
Loans receivable from U.S. Energy Biogas Corp. (a)	102,277
Unpaid interest on loans receivable from U.S. Energy Biogas Corp. (November and December 2006)	2,056
Carrying value of royalty interest in U.S. Energy Biogas Corp. (b)	6,800
Carrying value of loan origination fees (net of accumulated amortization of $246)	1,094
Accrued income from royalty interest in U.S. Energy Biogas Corp.	921
Loan enforcement related fees to be reimbursed by U.S. Energy Biogas Corp.	820
U.S. Energy Biogas Corp. receivable	**113,968**

(a) Loans receivable from U.S. Energy Biogas Corp.

The interest rate on the USEB Loans was 11.0% per annum with a maturity date of April 8, 2019, subject to mandatory prepayment provisions and prepayment at the option of the lender after 10 years. The USEB Loans were denominated in Canadian dollars and principal and interest was paid monthly. The USEB Loans are collateralized by all the assets of USEB.

As a result of its Chapter 11 filing on November 29, 2006, USEB ceased interest and principal repayments on this loan commencing November 30, 2006, which included interest for the month of November.

(b) Royalty interest in U.S. Energy Biogas Corp.

The Fund, through Countryside Canada, acquired a convertible royalty interest in USEB ("USEB Royalty Interest") for $7,884 [US $6,000] at closing of the Initial Offering.

NOTE 9 – OTHER ASSETS

Other assets consist of the following:

	2006 $	2005 $
Deferred financing fees, net of accumulated amortization of $906 (2005 - $215)	3,258	4,671
Loan origination fees, net of accumulated amortization in 2005 of $156) [note 8]	-	1,184
Long-term receivable [note 8]	-	571
Fair value of foreign exchange option contract	101	215
Fair value of interest rate swap and other [note 12]	217	253
	3,576	**6,894**

Deferred financing fees related to the original credit facility of $415 were written off in the second quarter of 2005 because the Amended Credit Facility was entered into in order to finance the acquisition of Ripon Power [note 12].

Approximately $3,922 in costs related to the Debentures were deferred and will be amortized over the term of the Debentures. These have been included in deferred financing fees commencing in the fourth quarter of 2005.

Loan origination fees and long-term receivable related to the Fund's accrued royalty interest entitlement in USEB, previously grouped with other assets, have been reclassified to U.S. Energy Biogas Corp. receivable as described in note 8.

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

At the beginning of the year, the Fund had 35 foreign exchange option contracts remaining. The Fund does not apply hedge accounting and as a result the contracts are recorded at their fair value at each reporting period with the gain or loss being included in loss (gain) on derivative instruments on the consolidated statements of income and deficit.

During the year, the Fund exercised four foreign exchange option contracts resulting in a realized gain of $16. As at December 31, 2006 the Fund had 23 remaining foreign exchange option contracts. An unrealized loss of $111 representing the change in the fair value of these option contracts has been recorded in the consolidated statements of income and deficit for the year ended December 31, 2006 (2005 – $4).

NOTE 10 – PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following:

	2006		2005	
	Cost $	Accumulated amortization $	Cost $	Accumulated amortization $
Land	2,904	-	2,898	-
Buildings	3,366	324	3,149	187
Equipment				
Plant and distribution	71,591	8,894	70,431	4,173
Computers	234	51	95	26
Office	240	26	38	8
Vehicles	169	82	169	49
Construction in process	1,917	-	139	-
Equipment under capital lease	352	39	352	21
	80,773	9,416	77,271	4,464
Net book value		**71,357**		**72,807**

NOTE 11 – OTHER INTANGIBLES

Other intangibles consist of the following:

	2006 $	2005 $
Customer relationships, net of accumulated amortization of $1,713 (2005 - $1,090)	11,363	11,986
Power purchase agreements, net of accumulated amortization of $8,199 (2005-$2,663)	57,762	63,092
	69,125	**75,078**

Customer relationships relate to the purchase of the District Energy Systems. Power purchase agreements were acquired as part of the purchase of the Ripon Power assets.

NOTE 12 – LONG-TERM DEBT

Through a syndicate of banks led by Toronto-Dominion Bank (the "Lenders"), Countryside District Energy's (the "Borrower") amended and restated credit agreement , dated November 14, 2005 provides up to a $78,000 revolving credit commitment. The Amended Credit Facility also allows for a swing line of credit in the amount of $2,000 and has the same three year maturity as the revolving credit commitment. Advances under the Amended Credit Facility are available to be drawn in either Canadian or U.S. dollars. The interest rate on Canadian dollar advances is based on either Canadian prime rate or bankers' acceptances and U.S. dollar advances are based on either U.S. base rate or London Interbank Offered Rate ("LIBOR"). The applicable margin or stamping fee on the respective base rate is tied to the actual leverage ratio of Countryside Canada, which is calculated quarterly utilizing its' most recent quarterly financial results. Therefore, a change in the leverage ratio could result in an increase or decrease in the effective rate of interest paid on the long-term debt. The financial covenants have been amended under the most recent waiver and amendment to Amended Credit Facility dated January 25, 2007. For purposes of calculating the leverage ratio and concomitant pricing, the covenant calculation includes the operating results of Ripon Power and exclude the cash received from USEB. A standby fee, also tied to the actual quarterly leverage ratio of Countryside Canada, is charged on the unutilized portion of the Amended Credit Facility including the swing line of credit. The Amended Credit Facility further allows for letters of credit which if issued, correspondingly reduce the amount of available revolving credit commitment. The fee paid on the letters of credit is also tied to the leverage ratio of Countryside Canada

As at December 31, 2006, $48,500 was drawn under the terms of the Amended Credit Facility in the form of banker's acceptances, plus a stamping fee of 3.25%. Of the $2,000 swing line of credit, $674 was drawn at December 31, 2006 under Canadian prime rate loans, plus a spread of 2.25%. Letters of credit totaling $310 were issued in the fall of 2006 in favour of the Ontario Power Authority ("OPA") and are set to expire one year from their date of issue. The OPA letters of credit are part of the incremental completion and performance security required as part of the Combined Heat and Power Contract entered into on October 16, 2006 between Countryside London Cogen and the OPA. At December 31, 2006, these letters of credit were subject to a fee of 3.25% per annum and amounts undrawn under the Amended Credit Facility were subject to a standby fee of 0.75% per annum.

USEB's voluntary filing for reorganization under Chapter 11 of the U.S. Bankruptcy Code, along with its non-payment of debt service commencing on November 29, 2006, triggered cross-defaults under the terms of the Amended Credit Facility. As of January 25, 2007, the Lenders have granted the Fund a waiver of these default provisions through May 31, 2007 in conjunction with their approval of the USEB Settlement Agreement (see note 8). Any future payments received from USEB under the USEB Settlement Agreement are required to be applied first to the repayment of outstanding amounts under the Amended Credit Facility pursuant to the mandatory prepayment provisions therein. Such payments will also reduce the amount committed under the Amended Credit Facility. As a result, the full amount outstanding is reflected as a current liability. On March 14, 2007, the total revolving credit commitment was permanently reduced to $42,917 as a result of the US$30 million installment payment received from USEB and the corresponding mandatory prepayment by the Borrower in the amount of $35,083 in accordance with the terms of the Amended Credit Facility (see note 8).

The Borrower entered into an interest rate swap agreement to fix the interest rate paid on $47,000 of its long-term debt at a rate of 3.87%, which is based on banker's acceptances. The swap matures on June 27, 2008 and payments are due every three months. The effective rate of interest for amounts drawn under the Amended Credit Facility is the funded base rate plus the stamping fee, increased or decreased by any amounts due or owed, respectively, by the Borrower under the interest rate swap.

As at December 31, 2006 the fair value of the interest rate swap agreement was $216 favourable (2005 - $253 favourable) and has been included with other assets on the consolidated balance sheet. In conjunction with the mandatory prepayment of the Amended Credit Facility on March 14, 2007, the interest rate swap was terminated, which resulted in proceeds of $209.

Amounts drawn under the Amended Credit Facility are principally collateralized by, (i) mortgages, general security agreements and assignment of insurance proceeds by Countryside District Energy (ii) a general security agreement by London Cogen (iii) a guarantee and general security agreement by Countryside Canada and (iv) an assignment of an amended secured promissory note dated November 14, 2005 issued by Countryside US Holding to Countryside Canada in the principal amount of US $52,139 which in turn is collateralized by a secured project note issued by Ripon Cogeneration LLC and a pledge by Countryside US Holding of its membership interest in Ripon Power.

At December 31, 2006, the fair value of the amount drawn on the Amended Credit Facility approximated its carrying value.

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

NOTE 13 – INCOME TAXES

The income tax (recovery) expense consists of the following:

	2006	2005 (as restated – note 3)
	$	$
Current	438	22
Future	(1,779)	30
(Recovery of) provision for income taxes	**(1,341)**	**52**

The future income tax asset and liability consist of the following:

	2006	2005 (as restated – note 3)
	$	$
Future income tax asset		
Current:		
Losses available for carry forward	885	1,296
Long Term:		
Losses available for carry forward	3,229	2,004
Property, plant and equipment	1,272	924
Subordinated interest	1,213	1,211
Deferred financing fees	415	-
Future income tax asset	**7,014**	**5,435**
Future income tax liability		
Current:		
Gain on interest rate swap	75	-
Long Term:		
Customer relationships	3,523	4,395
Gain on interest rate swap	-	91
U.S. transaction and other costs	2,015	1,329
Future income tax liability	**5,613**	**5,815**

The (recovery of) provision for income taxes differs from the expense that would be obtained by applying Canadian statutory tax rates as a result of the following:

	2006	2005 (as restated – note 3)
	$	$
Consolidated income before provision for income taxes	11,463	11,296
Income not subject to tax accounting	13,481	13,750
Income (loss) before income taxes	(2,018)	(2,454)
Combined federal and provincial income taxes at statutory rate of 34% [2005 - 37%] and U.S. statutory rate of 40% [2005 – 40%]	(568)	(1,002)
Manufacturing and processing deduction	(25)	(42)
Change in future tax rates	(562)	45
Losses not benefited	901	2,550
Losses not previously recognized	(1,462)	(1,521)
Other	375	22
(Recovery of) provision for income taxes	**(1,341)**	**52**

At December 31, 2006, the Fund has non-capital losses available for carry forward of approximately $21,524 to reduce future taxable income. The tax benefit associated with Countryside Canada in respect of approximately $9683 of these losses has not been recognized in the accounts of the Fund as at December 31, 2006. The majority of these losses expire starting in the year 2011.

The Fund loaned $107,000 to USEB in 2004, and loaned Countryside US Holding $60,638 [US $52,139] by way of an intercompany note during 2005. The Fund has been advised by US tax counsel that interest paid by USEB on the USEB Loans should be deductible by USEB and that interest paid by Countryside US Holding on the intercompany note should be deductible by Countryside US Holding for US federal income tax purposes. The interest on the USEB loans is not subject to any US withholding tax; however, the Countryside US Holding note is subject to US withholding tax at 10%. The consolidated financial statements of the Fund reflect this opinion. However, there is a risk that the Internal Revenue Service ("IRS") could successfully challenge such treatment, resulting in some or all of the interest on the USEB Loans being non-deductible by USEB and/or also resulting in some or all of the interest on the intercompany note to Countryside US Holding being non-deductible by Countryside US Holding and some or all of such interest being subject to US withholding tax at rates of 10% to 30%. As a result, the amount of funds available for distribution to Unitholders could be reduced.

In addition to the foregoing, and in common with other complex international business structures, the Fund is subject to various additional uncertainties concerning the interpretation and application of Canadian and U.S. tax laws. If tax authorities disagreed with the Fund's application of tax laws, the Fund's profitability and cash flows could be adversely affected.

On October 31, 2006 the Canadian federal government announced tax proposals pertaining to taxation of distributions paid by income trusts and changes to the personal tax treatment of trust distributions that will be applicable starting 2011. Currently, the Fund does not pay income tax as long as distributions to Unitholders exceed the amount of the Fund's income that would otherwise be taxable. The proposed new law will result in a two-tiered tax structure similar to that of corporations whereby the taxable portion of distributions would be subject to income tax, while taxable Canadian Unitholders would receive the favourable tax treatment on distributions currently applicable to qualifying dividends. As of the date of these financial statements, the government's proposal remains draft and has not been passed into law.

NOTE 14 – TRUST UNITS

The Declaration of Trust provides that an unlimited number of trust units may be issued. Each trust unit represents an equal undivided beneficial interest in any distribution from the Fund and in any net assets of the Fund in the event of termination or wind-up. All trust units are of the same class with equal rights and privileges.

The trust units are redeemable at the holder's option at an amount equal to the lesser of: (a) 90% of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10-trading day period ending on the date on which the trust units were surrendered for redemption (the "Redemption Date"); and (b) 100% of the "closing market price" on the principal market on which the trust units are quoted for trading on the Redemption Date. Redemptions are subject to a maximum of $50 in cash redemptions in any particular month.

On November 14, 2005, the Fund closed an offering of 4,720,000 trust units and $63,965 [US $55,000] aggregate principal amount of 6.25% Debentures [note 6]. The trust unit portion of the offering resulted in net proceeds of approximately $41,155 after the deduction of $2,207 in commissions and $770 in related transaction costs.

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

	Number of Units	Amount $
Balances at April 8, 2004 and December 31, 2004	14,905,366	136,350
Issued trust units at November 14, 2005	4,720,000	44,132
Issue costs		(2,977)
Balances at December 31, 2005	19,625,366	177,505
Exchange of Debentures	1,186,731	11,413
Balances at December 31, 2006	**20,812,097**	**188,918**

The reconciliation of the denominator in calculating diluted per trust unit amounts is as follows:

	2006	2005
Weighted average number of trust units outstanding, basic	19,968,697	15,513,147
Effect of dilutive securities: Debentures	5,678,531	775,418
Weighted average number of trust units outstanding, diluted	25,647,228	16,288,565

NOTE 15 - CONCENTRATION OF CREDIT RISK

Each of the Cogen Facilities has one primary utility customer as well as one industrial customer to which it provides steam, under long-term contract. The Fund's credit risk exposure in the event of non-performance by its customers is limited to the face value of the receivables. No collateral is required on these receivables.

Electricity revenue and capacity sales, pursuant to the PPA with Southern California Edison ("SCE") and Pacific Gas & Electric ("PG&E") accounted for 32% (2005 - 31%) and 28% (2005 - 17%), respectively of revenue for the respective years ended December 31. Approximately 26% (2005 - 51%) of the year end accounts receivable balance was due from SCE, and 45% (2005 – nil) was due from PG&E relating to electricity revenue and capacity sales.

The Fund is dependent upon USEB to monetize the obligations agreed to under the USEB Settlement Agreement as described in note 8 above, including the exit financing required for USEB to repay the balance of the USEB Allowed Secured Claim outstanding, due on May 31, 2007.

NOTE 16 – COMMITMENTS AND CONTINGENCIES

Commitments

(a) As of April 8, 2004, Countryside Canada delivered a performance guarantee in favour of WPS Energy Services, Inc. ("WPS") respecting Countryside District Energy Holding Corp.'s future obligations to WPS under the Master Natural Gas Sales and Purchase Agreement dated December 1, 2001 (the "Purchase Agreement"). All natural gas utilized by the London System (a division of Countryside District Energy Corp.) is purchased under the Purchase Agreement with WPS. Such guarantee is limited to an aggregate amount of $1,000 and to liabilities incurred prior to December 31, 2005 or such earlier date designated by Countryside Canada on 10 days notice to WPS. The Fund renewed the guarantee, effective January 1, 2006 to an aggregate amount of $1,200, covering the period up to December 31, 2008.

(b) On October 16, 2006, the Ontario Power Authority (the "OPA") and Countryside London Cogen entered into a Combined Heat and Power Contract ("CHP Contract") respecting the development, operation and sale of electricity from a to-be-built 17.25 MW gas cogeneration plant located in London Ontario (the "Facility"). The CHP Contract has a term of 20 years commencing on the Facility's commercial operation date.

Countryside London Cogen is obligated to design, build and operate the Facility in accordance with the Agreement and applicable laws, codes, rules and industry practices.

Countryside London Cogen is required to commence commercial operation (as defined in the CHP Contract) by June 1, 2008 (the "Commercial Operation Date"), failing which the Countryside London Cogen is subject to liquidated damages in accordance with a formula set forth in the OPA Contract. The Commercial Operation Date may be adjusted for force majeure. The maximum exposure to Countryside London Cogen under this provision would be approximately $1 million.

In addition, if the commercial operation date does not occur within one year after such date, then such failure would permit the OPA to terminate the CHP Contract unless Countryside London Cogen has paid all liquidated damages accruing to the one year date and provided the full amount of the required completion and performance security. The failure to reach the commercial operation date within 18 months after the commercial operation milestone would be considered an event of default giving rise to the right of OPA to terminate the CHP Contract and sue for damages.

Countryside London Cogen has provided completion and performance security to the OPA of $602 upon which the OPA may draw to satisfy any damage claims. Countryside London Cogen is obligated to replenish any amounts drawn upon.

(c) The Cogen Facilities are comprised of the "Ripon Facility" and the "San Gabriel Facility". Each facility has a gas turbine lease agreement with a third party, to have turbines available for their use during the year in the case of malfunction of the existing equipment. The annual cost of these leases is approximately $367 [US $315]. The leases expire in October 2012 and July 2007, respectively. Both leases are subject to an annual escalation amount based upon an inflation factor.

The Cogen Facilities have two power turbine lease agreements with a third party, one for each facility, to have a rotor, turbine casing and transition duct available for their use during the year in the case of malfunction of the existing equipment. The annual cost of each of these leases is approximately $58 [US $50]. Both leases expire in March 2009.

(d) Commencing October 1, 2006, the Cogen Facilities entered into a fuel purchase agreement with Sempra Energy Trading Corporation ("Sempra") that terminates on March 31, 2008. The Ripon Facility is required to purchase a minimum of 6,500 Million British Thermal Units ("MMBtu's") of natural gas each day and the San Gabriel Facility is required to purchase 6,400 MMBtu's of natural gas each day. The price of fuel for both facilities resets each month based upon a monthly index price for the location where the facilities are situated.

(e) Operation and maintenance agreements have been entered into with North American Energy Services Company ("NAES") for the operation and maintenance of each of the Cogen Facilities. The agreements cover the operation of the two plant facilities including administration of all payroll and benefits for plant staff, plant operations and compliance and facility level accounting. Annual fees for each of these agreements are $198 [US $170] plus an incentive payment, which is a maximum of $93 [US $80] per year. These agreements expire in 2011.

(f) Commitments under other operating leases at December 31, 2006 are: 2007 - $422; 2008 - $297; 2009 - $256; 2010 - $226; 2011 and thereafter - $204.

<u>Derivative Financial Instruments</u>

In addition to the interest rate swap contracts (note12), the Fund purchased thirty-six consecutive monthly "knockout" foreign exchange call option contracts, commencing in December 2005, which have an exercise price of US $0.89 per Canadian dollar, at a cost of $219 and a notional amount of approximately US$5,300. To the extent that the US/Canadian dollar exchange rate reaches $0.84 (the "knockout price") at any time while the option contracts are still in effect, the remaining unexpired monthly call option contracts will immediately expire.

Contingencies

A proceeding is currently pending before the California Public Utility Commission ("CPUC"), in which the CPUC is considering whether to apply a March 2001 ruling which decreased "Short Run Avoided Cost" or "SRAC" levels retroactively for the period from December 2000 to March 2001. Such a ruling could, in theory, apply to many Qualifying Facilities ("QF's") in California, including the Cogen Facilities and may lead utilities to seek refunds or offsets from the QF's which sold the utilities' power during such 4 month period. While the Fund believes that such a result is unlikely, the outcome of such a regulatory proceeding cannot be predicted with certainty. Even in the event of an adverse result, the Fund believes Ripon would have several meritorious legal defenses under federal and state law which should protect Ripon from any material adverse impact. However, there is no assurance that Ripon would prevail on such defenses if called upon to assert them. If the CPUC ultimately adopts a final order imposing a retroactive modification to the SRAC formula, and a remedy based thereon is ordered or authorized, and if such final order and remedy is not reversed on appeal or otherwise enjoined, QFs including the Ripon and San Gabriel Facilities could be required to make refunds and/or accept reduced payments (by way of offset of past overpayment against future payments for power delivered) under their respective PPAs. Such refunds or reduced payments could materially and adversely affect the Cogen Facilities' ability to generate distributable cash.

NOTE 17 – DEVELOPMENT AGREEMENT WITH CINERGY AND USEY

As of April 8, 2004 Countryside U.S. Power entered into a Development Agreement with an indirect subsidiary of Cinergy and USEY under which, subject to its terms and conditions, the Cinergy subsidiary and USEY may contribute their experience and financial resources to the acquisition, development, improvement and operation of energy projects that they choose to pursue and that will meet the Fund's investment and growth objectives. Countryside U.S. Power provides investment analysis and evaluation services on behalf of all parties to the agreement. In consideration for these services, Countryside U.S. Power is to be paid an annual fee of approximately $512 (US $440) from an indirect subsidiary of Cinergy and USEY. Commencing in May 2005, USEY stopped making payments with respect to its portion of the fees.

Pursuant to the USEB Settlement Agreement, the obligation for Countryside U.S. Power to provide services to USEY, and the obligation for USEY to pay Development fees to Countryside U.S. Power have been terminated. See note 8.

NOTE 18 – DISTRIBUTIONS TO UNITHOLDERS

Distributions totaling $1.035 per trust unit (2005 - $1.0285) being aggregate distributions of $20,738 (2005 - $16,145) were declared. For income tax purposes $10,500 (2005 - $5,531) of the distributions are treated as a return of capital.

Distributions are declared for unitholders of record on the last business day of a calendar month to receive distributions on or about the 30th day of the following month. Holders of units who are non-residents of Canada will be required to pay all applicable withholding taxes payable in respect of any distributions by the Fund.

NOTE 19 – STOCK-BASED COMPENSATION PLAN

Deferred Trust Unit Plan

The Fund has adopted a Deferred Trust Unit Plan for trustees of the Fund and non-management directors of Countryside Canada and its subsidiaries (the "Participants"). Participants may elect to have an amount equal to all or a portion of their annual directors' retainer used to increase the number of deferred trust units ("deferred units") they are entitled to. The Chairperson of the board of Countryside Canada also receives an award of deferred units as part of his annual directors' retainer. The deferred units are issued on the basis of the market price of the Fund's units on the Toronto Stock Exchange as of the date the compensation otherwise would have been paid, based on a weighted average formula. If at any time cash distributions are declared on the deferred units, additional deferred units will be credited to each Participant's account as of the record date of such declaration. The number of such additional deferred units will be calculated based on the then current market price. The maximum number of deferred units that may be granted under this plan is 150,000. A Participant has five years to achieve his or her required ownership level, which is equal to three times their annual directors' retainer. If at the end of such five year period, a Participant has not achieved his or her required ownership level, 100% of such Participant's annual directors' retainer payable thereafter shall be automatically allocated to the Plan until such time as the required ownership level is achieved. Deferred units do not entitle the holder to vote at any meeting of Unitholders. Each Participant shall have the right to exchange the deferred units held by such Participant for an equal number of Fund units following the date on which such Participant ceases to be a non-management director, net of tax withholdings. Deferred units are not transferable except by will or testamentary instrument. As of December 31, 2006, 1,440 deferred units had been awarded with a market value of $10.

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

NOTE 20 – SEGMENTED DISCLOSURE

The Fund indirectly owns and operates the District Energy Systems and the Cogen Facilities. It also had a loan to, and a convertible royalty interest in, USEB, which is included with the Fund's corporate administrative operations for reporting purposes. These three groups of assets represent the Fund's reportable segments at December 31, 2006.

The Fund analyzes the performance of its three operating segments based on earnings before interest, income taxes, unrealized derivative instrument and foreign exchange gains and losses, and depreciation and amortization ("adjusted EBITDA"). Adjusted EBITDA is not a standard measure under Canadian GAAP and hence may not be comparable to similar EBITDA information presented by other funds.

The Cogen Facilities were purchased on June 29, 2005, thus the comparative results in the twelve-month period ended December 31, 2005 only include the last six months of results of the Cogen Facilities whereas the twelve-month period ended December 31, 2006 includes a full twelve months of operations.

				2006
	District Energy	Cogen Facilities	Corporate and Other	Total
Revenues				
Energy	17,841	60,230	-	78,071
Other	1,858	268	12,260	14,386
	19,699	60,498	12,260	92,457
Expenses				
Fuel, operating and maintenance	13,473	39,544	-	53,017
General and administration [1]	1,189	3,507	4,454	9,150
	14,662	43,051	4,454	62,167
Adjusted EBITDA	5,037	17,447	7,806	30,290
Depreciation of property, plant & equipment				4,852
Other asset amortization				7,096
Operating income				18,342
Capital expenditures	2,163	546	690	3,399

For the years ended December 31 [all amounts in thousands of dollars except per trust unit amounts].

	District Energy	Cogen Facilities	Corporate and Other	Total
				2005 (as restated – note 3)
Revenues				
Energy	17,932	34,891	-	52,823
Other	1,894	49	12,395	14,338
	19,826	34,940	12,395	67,161
Expenses				
Fuel, operating and maintenance	12,894	22,004	-	34,898
General and administration[1]	1,046	2,747	7,156	10,949
	13,940	24,751	7,156	45,847
Adjusted EBITDA	5,886	10,189	5,239	21,314
Depreciation of property, plant & equipment				3,363
Other asset amortization				4,698
Operating income				13,253
Capital expenditures	834	-	21	855

[1] Including accrual of Manager's Subordinated Interest in Ripon Power and for 2005 including the non-cash expense of the estimated value of such Subordinated Interest as of such time.

	2006	2005 (as restated – note 3)
	$	$
Total assets		
District Energy	37,752	36,012
Cogen Facilities	114,979	124,041
Corporate and Other	133,460	133,050
	286,191	**293,103**

	2006	2005
	$	$
Total other intangibles, net		
District Energy	-	-
Cogen Facilities	57,762	63,092
Corporate and Other*	11,363	11,986
	69,125	**75,078**

* The other intangibles are reflected in "corporate and other" for segment presentation purposes. However, such intangibles relate to the purchase of the District Energy Systems during the Initial Public Offering on April 8, 2004.

All assets, liabilities and revenues located in Canada relate to the District Energy Systems and the London Cogeneration Project. All assets, liabilities and revenues located in the United States relate to Ripon Power, Countryside US Holding or Countryside U.S. Power, as well as the USEB Loans, USEB Royalty Interest, the income from the USEB Royalty Interest and the development fee revenue, which are earned from entities based in the United States.

Capital expenditures included in the table above include both non-expansionary expenditures for regular operations as well as capital expenditures for improvement or growth projects.

NOTE 21 – RELATED PARTY TRANSACTIONS

Management Agreement

On September 23, 2005, Countryside US Holding and Countryside Canada entered into a management agreement ("Management Agreement") with Countryside Ventures. Under the terms of the Management Agreement, effective November 1, 2005, Countryside Ventures commenced, providing management and administrative services to Countryside Canada and Countryside US Holding as well as new growth opportunities under long-term agreements. Effective November 1, 2005, Countryside Ventures commenced employing the Fund's current executive management team on a full time basis as well as its administrative and development staff. The Fund, through Countryside U.S. Power and Countryside Canada, has a right of first offer on all investment opportunities developed by Countryside Ventures that meet the Fund's investment criteria. In consideration for providing the management and administrative services under the Management Agreement, the Manager shall be entitled to reimbursement from Countryside US Holding and, to the extent the Manager provides services to Countryside Canada at its request, Countryside Canada, of all costs and expenses reasonably incurred by the Manager and its affiliates in carrying out the services described above. During 2006, a total of $2,424 (2005 - $424) was expensed related to the Management Agreement.

As of February 9, 2007, the Fund, Countryside Canada, Countryside US Holding and Countryside Ventures entered into the first amendment of the Management Agreement under which Countryside US Holding agreed to purchase, on June 29, 2007 (or earlier in the case of a Change of Control as defined in the Management Agreement) 85% of Countryside Ventures' subordinated interest in Ripon Power (the "85 % Interest") for cash and Fund units equal to $16,026 based on a unit price of $8.32. The consideration to be paid net of 85% of the existing liability of $3,032 as described in note 3, will be charged to income in the first quarter of 2007 and will consist of a minimum of 10% cash and will provide Countryside US Holding with an option to increase the cash component up to 25%. As of February 9, 2007, Countryside Ventures will have no further rights respecting (i) distributions from Ripon Power respecting the 85% Interest and (ii) any improvement of Ripon except respecting distributions on Countryside Ventures' remaining 15% interest in Ripon Power (the "15% Interest"). With respect to such 15% Interest, neither Countryside US Holding nor Countryside Ventures will exercise its option under the Management Agreement to exchange such 15% interest for Fund units prior to February 9, 2009 except in the case of a Change of Control as set forth in the Management Agreement.

Operating Agreement

In conjunction with the Management Agreement, Countryside US Holding and Countryside Ventures entered into an Operating Agreement on November 3, 2005 respecting Ripon Power which was effective as of July 1, 2005 (see note 3). This agreement will implement for the Ripon Power acquisition, the long-term incentive plan provided for in the Management Agreement. Under the terms of the Operating Agreement, Countryside US Holding will hold a preferred membership interest (the "Preferred Interest") entitling it to preferred distributions of "net cash flow" from operations and "net cash proceeds" from capital transactions as such terms will be defined in the Operating Agreement. Countryside US Holding and Countryside Ventures will hold subordinate membership interests (the "Subordinate Interests" or "Subordinated Interest") entitling them to residual distributions of net cash flows and cash proceeds made to members, after distributions made in respect of the Preferred Interest, in a ratio of 75:25. Countryside Ventures' Subordinated Interest distribution is subject to downward adjustment and mutual exchange options to convert the Subordinated Interest into units of the Fund pursuant to the formula provided in the Management Agreement. During 2006, a total of $3,104 (2005 - $1,515) was distributed to Countryside Ventures and a total of $9,312 (2005 - $4,545) was distributed to the Fund pursuant to the Operating Agreement, related to their respective Subordinate Interests.

Shareholders Agreement

As provided for in the Management Agreement, Countryside District Energy Corp. and Countryside Ventures are finalizing a Shareholders Agreement respecting Countryside London Cogeneration Corp. This agreement, will implement for the Countryside London Cogeneration investment, the long term incentive plan provided for in the Management Agreement ("Manager's CLCC Subordinated Interest"). Countryside Canada holds 1 preferred share in Countryside London Cogeneration Corp. (the "Preferred Share") entitling it to preferred dividends from "net cash flow" from operations and "net cash proceeds" from capital transactions as such terms will be defined in the Shareholders Agreement. Countryside Canada and Countryside Ventures hold 75 and 25 shares of common stock, respectively, in Countryside London Cogeneration Corp. (the "Common Shares") entitling them to dividends paid to common shareholders, after dividends paid to the preferred shareholders, in the ratio of their common share ownership (the "Common Dividends"). Countryside Ventures' Common Shares and Common Dividends are subject to downward adjustment and mutual exchange as provided in the Management Agreement except that certain adjustments have been made to the timing and calculations respecting the mutual exchange to account for the fact that Countryside London Cogeneration Corp.'s asset is a development project that is not expected to achieve commercial operation until mid-2008.

Administration Agreement

On September 26, 2005 the Fund and Countryside U.S. Power entered into a Management and Administration Agreement ("Administration Agreement") with Countryside Canada Ventures Inc. ("Countryside Ventures Canada"), which is a wholly owned subsidiary of Countryside Ventures. Under the Administration Agreement, which was effective November 1, 2005, Countryside Ventures Canada commenced providing management and administrative services to the Fund and Countryside Canada. In carrying out the services described above, Countryside Canada Ventures and its affiliates will be entitled to reimbursement from the Fund and Countryside Canada of all costs and expenses incurred in connection therewith. During 2006, a total of $410 (2005 – nil) was expensed with respect to the Administration Agreement.

Indemnification Agreement

On December 21, 2006, The Fund and Countryside Canada agreed to indemnify the principals of Countryside Ventures respecting certain claims arising from disputes with USEY, USEB and the USEB bankruptcy.

NOTE 22 – SUBSEQUENT EVENTS

USEB Settlement

On January 13, 2007, Countryside Canada reached an agreement in principle with USEY and its wholly-owned subsidiary, USEB, resolving all issues outstanding between the parties as described in note 8 above. Such settlement was approved by the Bankruptcy Court in an order entered on February 16, 2007.

Amalgamation

On January 1, 2007, the Fund undertook an amalgamation of Countryside Canada Acquisition Inc., Countryside District Energy Holdings Corp. and Countryside District Energy. The succeeding corporation is Countryside District Energy.

NOTE 23 – COMPARATIVE AMOUNTS

The comparative consolidated financial statements have been reclassified from statements previously presented to conform to the presentation of the current year consolidated financial statements.

UNITHOLDER INFORMATION

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Website
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Auditors
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London, Ontario

Transfer Agent
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Toronto, Ontario M5C 2W9

Investor Relations Firm
BarnesMcInerney Inc.
120 Adelaide Street West, Suite 2200
Toronto, Ontario M5H 1T1

Stock Exchange Listings
Toronto Stock Exchange (TSX): Trust Units: COU.UN
Debentures: CSD.DB.U

COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund

MANAGEMENT'S DISCUSSION AND ANALYSIS

Q4 For the Year Ended December 31, 2006 [all amounts in thousands of Canadian dollars except per Trust Unit amounts, unless otherwise stated]

March 26, 2007

PRESENTATION OF FINANCIAL INFORMATION

Management's discussion and analysis ("MD&A") of the consolidated financial condition and the results of operations of Countryside Power Income Fund (the "Fund") should be read in conjunction with the audited consolidated financial statements and notes thereto.

This MD&A provides information for the period from January 1 to December 31, 2006 and for the three months ended December 31, 2006, up to and including March 26, 2007.

Forward-Looking Information

This MD&A may contain forward-looking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time-to-time in the Fund's Annual Information Form dated March 31, 2006. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

Non-GAAP Measures

Earnings before interest, income taxes, unrealized and realized interest rate swap and foreign exchange gains and losses, and depreciation and amortization ("Adjusted EBITDA") is not a measure under Canadian GAAP and there is no standardized measure of Adjusted EBITDA and therefore, it may not be comparable to similar measures presented by other income trusts or companies. Adjusted EBITDA can be calculated from the Fund's GAAP statements as operating income, plus depreciation and amortization expense. Countryside Ventures LLC ("the Manager") of the Fund (as defined below) believes that Adjusted EBITDA is a widely accepted financial indicator used by investors to assess the operational performance of a company or an income trust, and its ability to generate cash through operations.

Distributable cash is not a measure under Canadian GAAP and there is no standardized measure of distributable cash and therefore, it may not be comparable to similar measures presented by other income trusts or companies. The Fund distributes substantially all of its cash on an on-going basis. Distributable cash is a widely accepted financial indicator used by investors to assess the performance of an income trust and its ability to generate cash for distributions through ongoing operations.

OVERVIEW OF FUND AND RECENT DEVELOPMENTS

2006 Highlights

- The Fund has made all declared distributions to unitholders at a payout ratio of 87% of distributable cash flow in the fiscal year ended 2006.

- The Fund's operations performed well with its California cogeneration facilities generating a year over year increase of 20% in US dollar Adjusted EBITDA on a full year basis (although this asset was owned by the Fund for only the second half of 2005), mainly as a result of operational improvements implemented subsequent to their purchase.

- The Fund executed on its organic growth strategy and was awarded a 20-year combined heat and power generation contract by the Ontario Power Authority.

  - The Fund executed a fixed price engineering, procurement and construction contract in January 2007 (the "London Cogeneration Facility") with commercial operation expected in mid-2008 and an estimated capital cost of $27million.
  - The cogeneration facility will have 17 megawatts of electric power generation capacity and 130,000 lbs/hr of steam generation capacity.

- On October 31, 2006, the Canadian Federal government announced tax proposals pertaining to the taxation of distributions paid by income trusts and changes to the personal tax treatment of distributions that would commence in the calendar year 2011.

- U.S. Energy Biogas Corp. ("USEB") voluntarily filed a petition for reorganization under Chapter 11 of the United States Bankruptcy Code on November 29, 2006. The Fund took immediate action to address this issue with the following results:

  - The Fund was able to reach a settlement with USEB through voluntary mediation in January 2007 that resolved all outstanding claims between the parties.
  - The USEB settlement was approved by the U.S. Bankruptcy Court on February 16, 2007 pursuant to an order which became final and non-appealable on February 26, 2007. It provides among other things, an allowed U.S. dollar denominated secured claim in USEB of US$99,000 (approximately $115,000) that will bear interest at 10% with a maturity of May 31, 2007.
  - In addition to scheduled interest payments, the Fund has received two payments from USEB totaling approximately $US 33,000 on its allowed secured claim and, in turn, has made a mandatory prepayment under the Fund's Amended Credit Facility (defined herein) in the amount of approximately $35,000.

- USEB's Chapter 11 filing caused a cross-default under the Fund's Amended Credit Facility. The Fund's syndicate of lenders has provided two waivers to the Amended Credit Facility, the latest of which provides, among other things:

  - A waiver of the cross-default provisions to the USEB loan until May 31, 2007
  - Continued access to the Amended Credit Facility
  - Permitted distributions to unitholders
  - Funding of construction of the London Cogeneration Facility

- A strategic review process has been initiated by the Fund's board of trustees in response to both the expected impact to the Fund of the USEB settlement and the federal government's proposed legislation to tax income trusts.
  - As previously disclosed, the Fund has retained Lehman Brothers, Inc. to assist and advise the Fund in identifying and considering the Fund's strategic alternatives with a view toward the best interests of unitholders.
  - The Fund has also considered a range of value enhancement alternatives, including a review of the Fund's prospects going forward as an income trust, a sale of the Fund (or its segments), a conversion to a corporate structure and/or a recapitalization.
  - As part of the strategic review process, the Fund is developing plans to remain a "stand alone" entity while it seeks to determine the Fund's value through a potential sale of the trust to interested buyers.

Fund Overview

The Fund, through its operating subsidiaries, owns two district energy systems and two gas-fired cogeneration facilities. The district energy systems are located in Canada, with one in Charlottetown, Prince Edward Island (the "PEI System") and one in London, Ontario (the "London System"), and together have approximately 122MW of thermal and electric generation capacity (collectively, the "District Energy Systems"). The cogeneration facilities consist of the Ripon cogeneration plant ("Ripon Facility") located near San Francisco, California and the San Gabriel cogeneration plant ("San Gabriel Facility") located near Los Angeles, California (collectively, the "Cogen Facilities") and have approximately 94 MW of electric generation capacity, sold approximately 600,000 Mlbs (thousand pounds) of steam in 2006. The Cogen Facilities are the only asset of, and are indirectly owned by

Ripon Power LLC ("Ripon Power"), which is in turn indirectly owned by the Fund. Additionally, the Fund holds indirect investments, through the Allowed Secured Claim, in USEB's 21 renewable power and energy projects (the "Renewable Projects") located in the United States, which currently have approximately 51MW of electric generation capacity and sold approximately 660,000 MMBtus of boiler fuel in 2006.

In light of recent events, the Fund has initiated a strategic review process in which it is currently re-evaluating its growth and operating strategy in order to determine the prospects for maintaining its original objectives when it became a publicly-traded income trust. Subject to the conclusion of the strategic review, the Fund's objectives are to maintain the stability and sustainability of cash distributions to unitholders of the Fund ("Unitholders") and increase, when prudent, cash distributions per unit.

Recent Developments

USEB Bankruptcy Filing and Settlement Agreement

On November 29, 2006 USEB and various subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York.

Prior to the filing by USEB, USEB had failed to provide various financial statements required under the USEB Loan. Further, the Fund had been in discussions with USEB concerning the restructuring of the USEB Loan in light of the fact that USEB might face cash flow problems in the first quarter of 2007. USEB rebuffed the Fund's attempts to restructure the USEB Loan. Instead, USEB filed for reorganization in order "to unlock shareholder value" according to its press release. It alleged in the bankruptcy case, among other things, that its business was operationally sound and solvent but that its current capital structure was impaired by a "flawed and unjustifiably onerous" loan agreement with the Fund that, absent a restructuring, would cause USEB to become insolvent.

The Fund strongly disagreed with USEB's allegations with respect to the Fund, and the USEB Loan.

Through mediation, the Fund, the Manager (including its members, individually), U.S. Energy Systems, Inc. ("USEY"), and USEB reached agreement in principle on January 13, 2007. The USEB settlement was approved by the Bankruptcy Court in principle on February 1, 2007 and formalized in (i) a settlement agreement by and among the parties ("Parties") (the "USEB Settlement Agreement") and (ii) a stipulation and final order authorizing USEB to use certain cash collateral and granting adequate protection payments in the form of cash interest to the Fund (the "Final Cash Collateral Order"). The Settlement Agreement and Final Cash Collateral Order were formally approved by order of the Bankruptcy Court on February 16, 2007 (collectively the "Approval Order"). The Approval Order became final and non-appealable on February 26, 2007 and the Settlement Agreement became effective on March 7, 2007.

The following summary of certain terms of the USEB Settlement is subject to and qualified in its entirety by reference, to all the terms of the Settlement Agreement and the Final Cash Collateral Order.

The USEB Settlement Agreement settles Countryside Canada's claims for all amounts claimed under the USEB Loan (including, without limitation, principal, pre and post-petition interest, loan breakage fees, expenses and indemnity) by allowance of a secured claim against USEB and its debtor affiliates of US$99,000 (or approximately $116,000 at the year end exchange rate) in the USEB Bankruptcy (the "Allowed Secured Claim"). (As of November 29, 2006, the pre-petition USEB loan balance was approximately $102,300; as of January 31, 2007, accrued unpaid pre- and post-petition interest under the USEB Loan was approximately $3,200; and as of December 31, 2006, the unamortized value and accrued income under the USEB Royalty was approximately $7,700.) The Allowed Secured Claim continues to be secured by a first lien on substantially all of the assets of USEB and its subsidiaries, which may be enforced through the enforcement remedies provided in the USEB loan.

The USEB Settlement Agreement provides for installment cash payments on the Allowed Secured Claim of US$3,000 on or before January 31, 2007 (which was paid in cash on January 31, 2007), US$30,000 on or before March 31, 2007 (which was paid in cash over a period from March 9-13, 2007), and the remaining principal balance on or before maturity at May 31, 2007. USEB may pay up to US$2,000 in USEY common stock which is registered or otherwise freely tradable with the number of shares to be calculated based on the weighted average closing price on the five trading days preceding the payment.

Outstanding principal amounts under the Allowed Secured Claim bear cash interest at a rate of 10% per annum from February 1, 2007, payable monthly in U.S. dollars. Upon any default in timely payment of principal or interest, the unpaid balance of the Allowed Secured Claim shall bear 12% default interest from the date of the last payment until such default has been cured or waived.

The USEB Allowed Claim may be prepaid at any time prior to May 31, 2007 without penalty. The USEB Allowed Claim is expected to be paid from the proceeds of an exit financing to be arranged by USEB as part of its formal plan to exit Chapter 11 bankruptcy and provided that no exit financing shall prime or be parri-passu with the liens securing the Allowed Secured Claim.

The USEY Parties on the one hand and the Countryside Parties on the other hand exchanged general releases covering all claims (as defined in the Settlement Agreement) arising before the Effective Date of the Settlement Agreement with certain exceptions including claims arising from the Allowed Secured Claim, the USEB Settlement Agreement, the Final Cash Collateral. Among other things, in such releases the USEY Parties released all claims against the Countryside Parties alleging any improprieties respecting the USEB Loan, the Countryside Parties released USEB from all claims relating to the USEB Royalty and all the Parties released each other from all claims relating to the Development Agreement.

On March 22, USEY announced that USEB reached an agreement in principle with the State of Illinois resolving outstanding issues between the parties in the bankruptcy proceedings. According to USEY, among other things, the State of Illinois has agreed not to pursue repayment of approximately US$63 million in interest-free loans in return for a payment of US$5 million on the effective date of USEB's plan of reorganization (which has not yet been filed) and no later than May 31, 2007. In addition according to USEY's announcement, USEB's Illinois-based projects will withdraw from the Illinois retail rate incentive program effective May 31, 2007. Such agreement is subject to the approval of the Bankruptcy Court. The Manager believes that USEB's agreement with the State of Illinois, if approved, will improve USEB's chances of consummating an exit financing which would satisfy the Allowed Secured Claim.

Countryside London Cogeneration Corp.

During the third quarter of 2006, the Fund's newly formed indirect subsidiary, Countryside London Cogeneration Corp. ("Countryside London Cogen"), was awarded a 20-year combined heat and power generation contract ("CHP Contract") by the Ontario Power Authority ("OPA") as part of a competitive bidding process. As a result, the Fund will add natural gas-fired cogeneration adjacent to its existing London System. The facility will have 17 megawatts of electric power generation capacity and provide additional thermal capacity to support future growth of the London System (the "London Cogeneration Facility"). The Fund executed an engineering, procurement and construction contract ("EPC Contract") with Meccon Industries, Inc. in January 2007, The London Cogeneration Facility is expected to begin commercial operation in mid-2008.

Countryside London Cogen is expected to provide long-term and predictable cash flow to the Fund through new power sales. The stability of the cash flow is expected to be primarily driven by the terms of the CHP Contract which provide for: (i) an initial annual $4.1 million capacity payment from the OPA (DBRS A (High)) that will partially escalate with the Consumer Price Index and that may be otherwise adjusted in accordance with the CHP Contract and (ii) energy payments based on the project's contractual seasonal heat rates ranging from 6,470 to 8,180 British Thermal Units (HHV) per kilowatt hour which are expected to result in positive cash flow margins. In addition, the power project may provide further accretive cash flow from sales from power production above the contractual capacity.

The capital cost of the cogeneration project is estimated at $27 million with an additional $3 million to expand the London System's chilled water system to support customer growth. The Fund expects to fund the full capital cost of the cogeneration project with cash on hand and credit available under its Amended Credit Facility. Construction and cost overrun risk is expected to be mitigated through a fixed-price engineering, procurement and construction contract and the leveraging of our existing energy infrastructure, permits, zoning and operational staff experienced in cogeneration technology.

The Fund believes it will minimize the key project risks through provision of a fully developed site, a turnkey, fixed price construction contract, a favourable power revenue/fuel supply pricing structure and proven cogeneration technology. Fuel procurement will be, via the London System, at rates expected to be based on a fuel price index that is highly correlated to electric power pricing and contractual rates.

Fund's Strategic Review Process

As previously disclosed, the Fund has retained Lehman Brothers, Inc. to assist and advise the Fund in identifying and considering the Fund's strategic alternatives with a view toward the best interests of unitholders. The Fund has also considered a range of value enhancement alternatives, including a review of the Fund's prospects going forward as an income trust, a sale of the Fund (or its segments), a conversion to a corporate structure and/or a recapitalization. As part of the strategic review process, the Fund is developing plans to remain a "stand alone" entity while it seeks to determine the Fund's value through a potential sale of the trust to interested buyers. To date, the board of trustees is encouraged by the results of the sale process and will continue to weigh those plans against a stand alone strategy with a view to maximizing unitholder value. A stand alone strategy may comprise several options, including a continuation of operations under the existing trust structure and the Fund's use of proceeds from the expected monetization of the USEB allowed secured claim to (i) fund (with the incurrence of additional leverage) the re-powering of the Cogen Facilities and the new 17 megawatt London cogeneration facility and/or (ii) a recapitalization which may involve a re-leveraging of the Fund with a return of capital to unitholders through a special distribution or unit buy back. Under a potential stand alone plan, any new growth-related investment or recapitalization strategy would be designed to provide accretive distributable cash flow to unitholders. However, the Fund currently does not intend to reinvest the proceeds from any future monetization of the USEB allowed secured claim until the strategic review process has been completed. The board of trustees of the Fund expects the strategic review process to be completed by the end of June 2007.

Amended Credit Facility

The USEB bankruptcy filing and its related payment default constituted a cross default under the Fund's Amended Credit Facility. The lenders under the Amended Credit Facility granted two waivers of the cross-default including most recently a waiver granted on January 25, 2007 which among other things (i) waived the cross-default provisions under the USEB Loan Agreement until May 31, 2007, (ii) reinstated access to the Amended Credit Facility, (iii) permitted unitholder distributions and permitted investments (including the London Cogeneration Facility) under the existing terms of the Amended Credit, (iv) approved the USEB Settlement, (v) required the Countryside Canada provide additional collateral relating to Ripon related assets and (vi) required the Manager to waive certain rights respecting the Manager's Ripon Subordinated Interest which was originally provided to the Manager in connection with the origination and acquisition of the Cogen Facilities in 2005.

As part of the strategic review process, the Fund intends to seek a long-term financing arrangement that reflects the expected monetization of the Allowed Secured Claim under the USEB Settlement Agreement and provides the Fund with sufficient credit capacity to meet its growth commitments, including the full funding of construction of the new London Cogeneration Facility scheduled to be completed in 2008. There can be no assurance as to the outcome of these efforts.

Countryside Power Income Fund

OPERATING RESULTS

Consolidated Results of the Fund

SUMMARY OF ANNUAL INFORMATION

As the Fund was created on February 16, 2004, and acquired the operations of the District Energy Systems on April 8, 2004, the comparative period ended December 31, 2004 includes 267 days of operations and therefore for comparative purposes, the 2004 consolidated financial statements of the Fund exclude the period from January 1, 2004 to April 8, 2004. The Cogen Facilities were purchased on June 29, 2005, thus the comparative results in the twelve-month period ended December 31, 2004 do not reflect the results of the Cogen Facilities and the results in the twelve-month period ended December 31, 2005 only include six months of results of the Cogen Facilities whereas the twelve-month period ended December 31, 2006 includes a full twelve months of operations.

For the period ended

	Twelve-month period ended December 31, 2006	Twelve-month period ended December 31, 2005 (as restated)	267-day operational period ended December 31, 2004
Energy Volumes			
Sales of Steam (Mlbs)	985,993	665,074	253,074
Sales of Hot Water (MMBtus)	283,293	313,313	178,782
Sales of Chilled Water (MTon/hr)	2,607	2,912	2,024
Sales of Electricity (MWh)	487,505	237,686	344
Fuel Consumed (MMBtus)	6,028,894	4,045,579	716,196
Financial Indicators	$	$	$
Total Revenues	92,457	67,161	21,136
Adjusted EBITDA	30,290	21,314	11,308
Net income	12,804	11,244	7,565
Net income per trust unit - basic (whole dollars)	0.64	0.72	0.51
Net income per trust unit – fully diluted (whole dollars)	0.64	0.72	0.51
Distributable cash	23,960	20,012	11,075
Distributions declared	20,738	16,145	11,161
Distributions per unit	1.035	1.041	0.749
Payout Ratio	86.6%	80.7%	100.7%
Total Assets	286,191	293,103	166,177
Total long-term financial liabilities	50,508	109,795	30,000

The Fund's total revenue in the twelve months ended December 31, 2006 was $92.5 million, an increase of $25.3 million compared with the same period last year. The majority of this increase was related to the inclusion of the Cogen Facilities' results in the first six months in 2006.

In March 2007, the Fund assessed the initial accounting for the granting of the Manager's Subordinated Interest in Ripon Power, and determined that compensation expense consisting of the fair value of the Subordinate Interest at the time of the grant was required to be recorded in the third quarter of 2005, which represented the period in which the Subordinate Interest was granted. As a result of the Manager's option to exchange its Subordinate Interest for a variable number of units of the Fund, the Subordinate Interest is required to be classified as a liability in the Fund's consolidated financial statements. The associated cash flow and value was not reflected in the purchase price paid by the Fund for Ripon Power. For the year ended December 31, 2005, general and administration expenses have been increased by $3,196, the provision for future income taxes has been reduced by $1,279, net income has been reduced by $1,917, closing deficit has been increased by $1,917, future income tax assets have been increased by $1,211, other long-term liabilities have been increased by $3,026 and the cumulative translation adjustment has been reduced by $102. Earnings per trust unit have been reduced by $0.13.

For the year ended December 31, 2006, the liability associated with the Subordinated Interest in the amount of $3,032 has been included in current liabilities as a component of accounts payable and accrued charges, in connection with the Fund's agreement to purchase 85% of the Manager's Subordinated Interest in June 2007.

The Fund's Adjusted EBITDA in the twelve-month period ended December 31, 2006 was $30.3 million, an increase of $9.0 million from the prior year period, due primarily to the addition of the Cogen Facilities offset by lower Adjusted EBITDA at the District Energy Systems resulting mainly from unseasonably warm weather and higher maintenance costs, as well as higher general and administration expenses.

Net income in the twelve months ended December 31, 2006, was $12.8 million, or $0.64 per unit, compared with $11.2 million or $0.72 per unit in the comparable period of 2005. In addition to the changes in Adjusted EBITDA described above, the increase of $1.6 million in net income from the prior year comparative period resulted from: (i) an increase in interest expense of $1.5 million related to the refinancing which took place in the fourth quarter of 2005; (ii) an increase in the tax recovery of $1.4 million primarily related to losses not previously benefited; and, (iii) an increase in losses on derivative instruments and foreign exchange of approximately $3.4 million principally related to the carrying value of the US dollar denominated Debentures and offset in 2005 by the cancellation of the interest rate swap attached to the project debt at the Cogen Facilities.

In the twelve-month period ended December 31, 2006, distributable cash of $24.0 million was generated by the Fund which exceeded last year's comparative period by $4.0 million. On a weighted average per-unit basis, distributable cash of $1.20 per trust unit decreased 7% per trust unit from the prior year comparative period. The decrease is due to the greater number of units outstanding at the end of the current year resulting from a recapitalization and de-leveraging of the Fund' balance sheet in November 2005 following the Cogen Facilities' acquisition and to a lesser extent the early exchange of US $10.8 million of the exchangeable subordinated debentures issued at Countryside Canada ("Debentures") into 1,186,731 units of the Fund during 2006. Distributions to Unitholders declared for the twelve-month period ended December 31, 2006 totaled $1.035 per unit. The Fund's payout ratio was 87% for the twelve-month period ended December 31, 2006.

Results of Cogen Facilities

This information is provided for reference purposes only and is not intended as a comprehensive comparison of financial results of the Cogen Facilities.

Power Purchase Agreements

The Ripon Facility is a nominal 49.5 MW (gross output) gas-fired cogeneration plant and the San Gabriel Facility is a nominal 44.5 MW (gross output) gas-fired cogeneration plant. The Cogen Facilities are qualifying facilities ("QFs") under the cogeneration regulations of the Federal Energy Regulatory Commission ("FERC") implementing the Public Utilities Policy Act of 1978 ("PURPA") and thus are currently exempt from rate regulation as an electric utility under federal and state law. Power sales comprise the bulk of the Cogen Facilities sales revenue. Electrical capacity and energy is sold pursuant to long-term power purchase agreements ("PPA") with Pacific Gas & Electric ("PG&E") and Southern California Edison ("SCE") for the Ripon and San Gabriel Facilities, expiring in 2018 and 2016, respectively. For the full operating year, energy payments under the PPA have historically contributed the majority of total power sales with capacity payments making up the balance.

In 2001, the Ripon Facility and PG&E entered into a five year interim agreement of the Ripon Facility's power purchase agreement which substituted PG&E's marginal production or short-run avoided cost ("SRAC") with a primarily fixed energy rate subject to adjustment for time of use factors ("Ripon Amendment"). The Ripon Amendment expired on June 30, 2006. Also in 2001, Ripon and SCE entered into a five year amendment of the San Gabriel Facility's PPA that modified certain components of SCE's SRAC formula through June 30, 2006 ("San Gabriel Amendment"). Commencing in July 2006, the Ripon Facility and the San Gabriel Facility received energy payments based upon the full SRAC energy pricing formulae (the "Original SRAC Pricing Formula"), which are generally based on a California natural gas price index, utility system heat rates and applicable time-of-use factors.

The expiration of the Ripon and San Gabriel Amendments, in June of 2006 and the resulting reversion back to the Original SRAC Pricing Formula is generally expected to have a neutral impact on the annualized combined energy margins of the Cogen Facilities going forward. A proceeding is pending before the California Public Utilities Commission ("CPUC") to consider possible prospective modifications to the SRAC pricing formula for all of the California utilities (See "Risks and Uncertainties – Electricity Pricing"). The CPUC is expected to issue one or more preliminary decisions in the future; however, the timing of the decisions has not been disclosed publicly. PG&E's

and SCE's obligation to purchase the energy and capacity from the Ripon Facility and the San Gabriel Facility continue until the PPAs expire in 2018 and 2016, respectively. The capacity payment pricing formulae are not subject to review by the CPUC and will remain unchanged.

Steam Sales Agreements

Process steam from each of the Cogen Facilities is sold under long term steam sales agreements, which are coterminous with the PPAs. On a combined basis, process steam sales accounted for approximately 8% (2005 – 6%) of total energy revenues in the twelve-month periods ended December 31 2006. Steam is sold by the Ripon Facility to the Fox River Paper Company ("Fox River"), and by the San Gabriel Facility to the Blue Heron Paper Company of California, LLC ("Blue Heron").

On or about March 1, 2007, a subsidiary of Neenah Paper Inc. (NYSE: NP) merged with and into Fox River Corporation, the parent of Fox River. Accordingly, Fox River is now an indirect subsidiary of Neenah Paper Inc.

Fuel Supply Agreements

Full natural gas requirements were supplied to the Cogen Facilities under contracts with BP Energy Company ("BP") that expired on June 30, 2006. In the period from July 1, 2006 to September 30, 2006, the Cogen Facilities entered into an agreement to purchase their natural gas requirements from BP at pricing which was reset monthly and correlated with a location-based gas index price.

Commencing October 1, 2006, the Cogen Facilities entered into fuel purchase agreements with Sempra Energy Trading Corporation ("Sempra") that terminate on March 31, 2008. Under such agreements, the Ripon Facility has agreed to purchase 6,500 Million British Thermal Units ("MMBtu's") of natural gas each day and the San Gabriel Facility has agreed to purchase 6,400 MMBtu's of natural gas each day. The price of fuel for both facilities resets monthly and is correlated with location-based gas index prices.

Cogen Facilities' Financial Results (US$)

	Three-month period ended December 31, 2006	Three-month period ended December 31, 2005	Twelve-month period ended December 31, 2006	Twelve-month period ended December 31, 2005 (as restated)
Energy Volumes				
Sales of Electricity (MWh)	120,162	103,633	484,439	586,794
Sales of Steam (Mlbs)	123,093	125,893	600,038	500,395
Fuel Consumed (MMBtus)	1,204.295	1,083,812	4,960,189	5,679,880
Financial Indicators (US $000)	**US$**	**US$**	**US$**	**US$**
Cogen Facilities' Energy Revenues	12,562	12,637	53,164	57,050
Electrical Energy	*9,496*	*9,882*	*34,086*	*39,000*
Electrical Capacity	*2,262*	*1,746*	*14,670*	*14,679*
Steam	*804*	*1,009*	*4,408*	*3,371*
Other Revenues	87	26	236	106
Fuel and Consumables Expense	7,865	6,907	28,142	33,844
Operating, Labour and Maintenance Expense	2,217	1,950	6,696	7,919
General and Administration Expense	242	471	1,059	1,462
EBITDA before Subordinated Interest (US$000)	**2,325**	**3,335**	**17,503**	**13,931**
Manager's Subordinated Interest[1]	26	601	2,104	4,251
EBITDA (US$000)	**2,299**	**2,734**	**15,399**	**9,680**
Depreciation and Amortization Expense	1.962	1,988	7.901	6,749
Operating Income (Loss) (US$000)	**337**	**746**	**7,498**	**2,931**
	CDN$	**CDN$**	**CDN$**	**CDN$**
EBITDA ($000)	**2,649**	**3,195**	**17,447**	**11,698**
Operating Income (Loss) ($000)	**408**	**872**	**8,496**	**3,542**

[1] The Subordinated Interest expense for 2005 includes a non-cash expense of US$2,602 reflecting the estimated value of the Manager's Subordinated Interest at such time.

The results of the Cogen Facilities will be discussed in thousands of US Dollars since the exchange to Canadian dollars skews the actual results of operations.

Following the acquisition of the Cogen Facilities in 2005, the Manager initiated an effort to improve the operations to economically benefit from the Cogen Facilities' inherent optionality. From the spring of 2006, the Cogen Facilities' operations were economically optimized on a daily basis, taking into account factors such as electricity capacity and energy pricing, natural gas pricing, steam demand and pricing, as well as heat rates. The focus on economic optimization has resulted in an increase in cash flow compared with prior year periods and when operating base load.

Energy Revenues and Volumes

In the three-month period ended December 31, 2006 electrical energy sales volumes increased by 16% from the prior year comparative period. The increase in electrical energy sales volumes resulted from a maintenance outage of the Ripon Facility during November and December of 2005. The 17% decrease in electrical energy sales volume in the twelve-month period ended December 31, 2006 when compared with the prior year period was primarily due to the shut down at the Ripon Facility from January to mid-March 2006 and the economic optimization of the Cogen Facilities throughout 2006.

Electrical energy revenue decreased by 4% and 13% in the three-month and twelve-month periods ended December 31, 2006, respectively, when compared with the prior year periods due primarily to economic optimization at both Facilities throughout 2006, coupled with lower index fuel and energy prices in the fourth quarter 2006. In the three months ended December 31, 2006, capacity revenue increased 30% from the prior year comparative period due primarily to the maintenance outage of the Ripon Facility during November and December of 2005. In the twelve-month period ended December 31, 2006, capacity revenues were generally in line with the prior year period.

In the three-month periods ended December 31, 2006, steam sales volumes decreased by 2% from the prior year comparative period. In the twelve-month period ended December 31, 2006, steam sales volumes increased 20% when compared with the prior year period due to increased steam demand from the facilities' steam customers.

Steam revenue decreased 20% in the three-month period ended December 31, 2006 due to lower steam prices in the fourth quarter 2006 as a result of lower natural gas prices which drive steam pricing. The 31% increase in steam revenue in the twelve-month period ended December 31, 2006 was primarily due to increased steam demand from the facilities' hosts throughout the year.

Other revenues consist of interest income earned during the period which increased $61 in the three-month and $130 in the twelve-month comparative periods due to higher cash balances on which interest was earned.

Fuel and Consumables Volumes and Expense

In the three-month period ended December 31, 2006, fuel consumed increased 11% from the prior year comparative period. The increase in fuel consumption was due to lower electricity production in the prior year period. The 13% decrease in fuel volume in the twelve-month period ended December 31, 2006 when compared with the prior year period was primarily due to the planned outage at the Ripon Facility from January to mid-March 2006, coupled with lower production due to economic optimization at both Cogen Facilities.

Fuel and consumables expense in the three-month and twelve-month periods ended December 31, 2006 increased by 14% and decreased by 17%, respectively, when compared with the prior year periods. In the three-month period, the increase in fuel and consumables costs was due to higher power production at the Cogen Facilities when compared to the fourth quarter 2005. In the twelve-month period, the decrease in fuel and consumables costs was due to the lower power production when compared with the full year 2005.

During periods when the Cogen Facilities are not operating, excess natural gas or fuel purchased under the gas purchase agreement but not consumed is released to the fuel supplier based on the market value of the fuel at such time. Such releases will result in a gain or a loss compared to the monthly index-based price paid under the gas purchase agreements, and is accounted for as an adjustment to the fuel and consumables expense. The cost of additional gas purchased in excess of the volume agreed under the gas purchase agreement is accordingly added to the fuels and consumables expense. Operating decisions to incur gains or losses resulting from the release of natural gas, as well as additional purchases of natural gas beyond contracted purchases for use in power generation are made in the context of their expected impact to the Cogen Facilities' net margins.

Total Non-Fuel Expenses

Operating, labour and maintenance expense in the three-month period ended December 31, 2006 increased by 14% when compared with the prior year period. The increase was due to a hot section overhaul at the Ripon Facility in the fourth quarter 2006. In the twelve-month period ending December 31, 2006 the decrease in non-fuel expenses was 15% due to a hot section overhaul performed at the San Gabriel Facility in 2005 offset by the hot section overhaul at the Ripon Facility in the current period.

General and administration expense in the three-month and twelve-month periods ended December 31, 2006 decreased 49% and 28%, respectively, when compared with the prior year periods as a result of reduced professional and management fees being incurred in 2006 under the Fund's ownership.

The Subordinated Distribution (as defined below in the section "Transactions With Related Parties – Operating Agreement") accrued to the Manager was $26 and $2,104, respectively in the three-month and twelve-month periods ended December 31, 2006. Pursuant to the Operating Agreement between the Manager and the Fund, the Fund and Manager share the Subordinated Distribution on a 25:75 basis, respectively, as earned. The Fund's share of the Subordinated Distribution was $78 and $6,312 respectively in the three-month and twelve-month periods ended December 31, 2006, reflecting the improved performance of the Cogen Facilities.

EBITDA

EBITDA decreased by 16% in the three-month period and increased by 59% in the twelve-month period ended

December 31, 2006 compared with the prior year periods. The change in the three month period ended December 31, 2006 is due to the lower natural gas and associated electric energy prices in 2006 than in the prior period, as well as higher non-fuel costs associated with a hot section overhaul at the Ripon Facility. In addition to the impact of the non-cash expense of the Manager's Subordinated Interest in 2005, the increase in the twelve-month period is due to the economic optimization of the operations in 2006, combined with higher fuel and associated electric energy prices during the first part of the year, compared to the prior year period.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased by 1% in the three-month period and increased by 17% in the twelve-month period ended December 31, 2006 when compared with the prior year periods. The increase in the twelve-month period was a result of recording the acquired property, plant and equipment and other intangibles on the date of acquisition of Ripon Power on June 29, 2005 at their fair values, and their corresponding higher depreciation and amortization expense recorded beginning in the third quarter of 2005.

Results of District Energy Systems

This information is provided for reference purposes only and is not intended as a comprehensive comparison of financial results of the District Energy Systems.

The District Energy Systems' revenue is mainly derived from long-term energy sales contracts with long-standing and creditworthy customers. The energy sales contracts are generally structured with energy and capacity payments, with the energy component typically providing for the pass through of changes in fuel prices to the customers. The energy rates paid by customers in London are generally reflective of the price of natural gas and are adjusted upward or downward to compensate for changes in the price of natural gas. In regard to the PEI System, the energy rates paid by larger customers are generally reflective of the cost and mix of fuels and are adjusted upward or downward to compensate for changes in the price of fuel. Smaller customers of the PEI System have rates based on the local price of fuel oil. For such customer rates, changes in the local fuel price will have a greater impact on the revenues of the PEI System than the impact that such changes will have on the cost of operation of the PEI System. As a result of the energy rate pricing structures, the District Energy Systems' revenue can increase or decrease depending on changes in fuel prices and, to a lesser extent, the fuel mix. During the last year, the market price fluctuations for natural gas have affected our District Energy Systems in terms of both decreased fuel costs and corresponding decreased energy revenues. Due to the pricing structure described above, fuel price changes may impact energy-related revenues and fuel and consumables expense considerably, but have a limited impact on EBITDA.

Countryside Power Income Fund

District Energy Financial Results

	Three-month period ended December 31, 2006	Three-month period ended December 31, 2005	Twelve-month period ended December 31, 2006	Twelve-month period ended December 31, 2005
Energy Volumes				
Sales of Steam (Mlbs) (Combined PEI & London Systems)	104,288	114,190	385,954	422,826
Sales of Hot Water (MMBtus) (PEI System only)	85,123	88,053	283,293	313,314
Sales of Chilled Water (MTon/hr) (London System only)	315	268	2,606	2,913
Fuel Consumed (MMBtus) (Combined PEI & London Systems)	295,883	305,587	1,068,614	1,138,032
Financial Indicators [000's]		$		$
District Energy Systems' Energy-related Revenues	4,680	5,188	17,841	17,932
Energy	[illegible]	*3,314*	[illegible]	*10,561*
Capacity	[illegible]	*1,874*	[illegible]	*7,371*
Other Revenues	445	447	1,858	1,894
Fuel and Consumables Expense	2,481	2,688	8,732	8,548
Operating, Labour and Maintenance Expense	1,231	1,107	4,741	4,346
General and Administration Expense	223	280	1,189	1,046
EBITDA	**1,190**	**1,560**	**5,037**	**5,886**
Depreciation and Amortization Expense	382	348	1,505	1,469
Operating Income	**808**	**1,212**	**3,532**	**4,417**

Energy Volumes and Revenues

In the three-month period ended December 31, 2006, the District Energy Systems' steam sales volumes decreased by 9% and hot water sales volumes decreased by 3 % compared with the prior comparative period. In the twelve-month period ended December 31, 2006 both steam sales and hot water sales volumes decreased by 9% and 10% respectively. This reduction was principally driven by unseasonably warm weather during the principal heating season during the first and fourth quarters of 2006, resulting in lower energy requirements from customers.

In the three-month period ended December 31, 2006, total revenues decreased by 10% from the prior year comparative period. The decrease in energy revenue of 16% was due primarily to lower sales volumes and energy rate decreases as a result of lower natural gas prices for the London System. Capacity payments were consistent with the prior comparative period. Capacity payments are fixed payments, which are received regardless of energy volumes delivered.

In the twelve-month period ended December 31, 2006, total combined revenues were consistent with the prior year comparative period. Decreased energy revenue of 3% was offset partly by increased capacity revenue of 2%. Energy revenue decreased from the prior period primarily as a result of lower sales volumes. Capacity revenue increased from the prior period as a result of contract adjustments and as a result of new customer connections for both the PEI System and the London System.

Other Revenues

Other revenues mainly consist of waste fuel fees received at the PEI System as well as other miscellaneous revenue items, and were consistent with the prior year for both comparative periods presented.

Fuel and Consumables Volume and Expense

In the three-month period ended December 31, 2006 total fuel consumed (in MMBtus) by the District Energy Systems decreased by approximately 3%. This decrease was primarily related to lower sales volumes for the London System. Fuel and consumables expense decreased by 8% for the three months ended December 31, 2006.

In the twelve-month period ended December 31, 2006 total fuel consumed by the District Energy Systems decreased by approximately 6%. The decrease was primarily due to reduced energy sales volumes to customers compared with the prior period.

Fuel and consumables expense increased 2% in the twelve-months ended December 31, 2006 primarily due to increased oil consumption in PEI due to planned maintenance of the wood and waste fuelled facilities and natural gas consumption in London due to plant maintenance of the electrical system.

Total Non-Fuel Expenses

For the period ended December 31, 2006, operating, labour and maintenance expense was 11% and 9% higher than in the prior year comparative three-month and twelve-month periods, respectively, due to planned maintenance outages on the wood and waste-fired systems at the PEI System, and maintenance at the London System.

General and administration expenses in the quarter ended December 31, 2006 decreased by 20%. The decrease was related primarily to the reallocation of resources to operations. General and administration expenses increased in the twelve-months ended December 31, 2006, when compared with the same period in 2005, by 14% due to increased audit and other professional fee allocations.

EBITDA

In the three-month period ended December 31, 2006, EBITDA margin was 16% lower than the prior year comparative quarter and for the twelve-month comparative periods, it was 14% lower. The margins decreased due to lower steam and hot water sales resulting mainly from unseasonably warm weather for both the PEI and London Systems during the primary heating season and higher costs of planned maintenance.

Depreciation and Amortization Expense

Depreciation and amortization expense for the three-month and twelve-month periods ended December 31, 2006 was consistent with the prior comparative periods.

Results of Corporate and Other

Corporate and Other results as presented below include the Fund's investment in USEB as well as its' corporate administrative operations, including those related to the Cogen Facilities.

Corporate and Other

	Three-month period ended	Three-month period ended	Year ended	Year ended (as restated)
	December 31, 2006	December 31, 2005	December 31, 2006	December 31, 2005
	$	$	$	$
Interest Income on Loans to USEB	2.995	2,868	11,517	11,546
Other Revenues	90	221	743	849
Total Revenue	3.085	3,089	12,260	12,395
General and Administration Expense	1,787	1,402	4,454	3,960
Adjusted EBITDA	**1,298**	**1,687**	**7,806**	**8,435**
Depreciation and Amortization Expense	390	366	1,492	1,824
Operating Income	**908**	**1,321**	**6,314**	**6,611**
Interest Expense (Consolidated Fund)	**1,657**	**2,237**	**7,104**	**5,578**

Revenue

Interest Income on Loans to USEB

Interest income on loans to USEB was $2,995 in the three-month and $11,517 in the twelve-month period ended December 31, 2006 based on a fixed interest rate of 11.0% per annum. The principal amounts of the loan balances remaining as at December 31, 2006 were $102,277. As a result of USEB's filing under Chapter 11 of the U.S. Bankruptcy Code, and non-payment of debt service on November 30, 2006, interest for the month of December was accrued at the default rate of 13% in accordance with the terms of the USEB loan documents. The interest accrued for the November and December payments was received by the Fund in January 2007. The USEB loans were scheduled to pay principal and interest monthly. As at the end of December 31, 2006, the Fund had received a total of $175 in principal repayments on the loans receivable from USEB during the quarterly period and $1,684 during the twelve-month period. Principal and interest payments were not received for the months of November and December 2006 as a result of the automatic stay provisions under the U.S. Bankruptcy Code. Please see section "Overview of Fund and Recent Developments – Recent Developments – USEB Settlement Subsequent to USEB's Voluntary Filing for Reorganization Under Chapter 11 of the U.S. Bankruptcy Code" for discussion of current status of the USEB loans. Pursuant to the terms of the USEB Settlement Agreement, the Fund will be permitted to accrue interest on its outstanding US dollar denominated Allowed Secured Claim from February 1, 2007 through to maturity and then at a default rate thereafter, if applicable. Under the USEB Settlement Agreement, the outstanding balance of the secured claim will bear interest at 10% and will be payable in cash on the second to last business day of each month (in U.S. dollars). Therefore, the Fund is now exposed to near term foreign exchange rate fluctuations with respect to the financial reporting of interest payable on the Allowed Secured Claim and is exposed to foreign currency transaction risk on any cash flow and/or proceeds received from USEB that are required to meet Canadian level commitments, including any future unitholder distributions or debt repayment. The strengthening of the U.S. dollar since the USEB bankruptcy filing has been favorable to the Fund upon the exchange to of U.S. dollar payments received from USEB to meet Canadian level obligations.

Other Revenues

Other revenues at the Fund level are comprised of USEB royalty interest, fee revenue from U.S. development partners as well as miscellaneous interest income on cash equivalents held at the Fund level. In the three-month comparative period ended December 31, other revenues decreased by 60% in the current period solely as a result of the fact that the Fund curtailed the accrual of the royalty interest from USEB in the fourth quarter of 2006 in light of USEB's filing under Chapter 11 of the U.S. Bankruptcy Code. The decrease of 12% in other revenues for the twelve-month comparative period was as a result of a reduction in Development Agreement fees accrued as described in the section " Transactions With Related Parties – Development Agreement with Cinergy and USEY" below, offset by an increase in interest earned due to higher cash balances maintained throughout 2006.

Total General and Administration Expenses

In the three-month period ended December 31, 2006, general and administration expense increased by 27% when compared with the prior year comparative period, primarily due to approximately $427 in transaction costs related to the Countryside London Cogen CHP contract. A portion of these costs were not deducted in the calculation of distributable cash per unit, as the costs were financed as part of the Countryside London Cogen transaction and not paid from cash flow from regular operations. This was offset by the write-off in the fourth quarter of 2005 of $165 of Development fee revenue and expenses owing from USEY accrued during the period from May through September 2005. The remainder of the increase in general and administration costs related primarily to incremental costs associated with increased professional fees paid relating to enforcement of Countryside U.S. Power's rights under the Development Agreement.

In the comparative twelve-month period ended December 31, 2006, general and administration expense increased 12% as a result of approximately $427 in transaction costs related to the Countryside London Cogen CHP contract coupled with approximately $155 in fees paid to the Fund's lending syndicate in connection with waivers and amendments to the Amended Credit Facility related to USEB financial non-compliance and bankruptcy issues. These cost increases were offset by the write-off, in 2005 of the $165 related to the Development fee revenue as described for the change in the three-month comparative period ended December 31, 2006. The remainder of the changes in general and administration costs related primarily to incremental costs associated with increased professional fees paid relating to Countryside U.S. Power's enforcement of rights under the Development Agreement.

Adjusted EBITDA

Adjusted EBITDA decreased by 23% in the three-month period ended December 31, 2006 and decreased by 7% in the twelve-month period ended December 31, 2006, when compared with the results from the comparative periods in 2005 due to the general and administrative expenses described above.

Depreciation and Amortization Expense

There was little change in depreciation and amortization expense in the comparative three-month period ended December 31, 2006. The 18% decrease from the prior year comparative twelve-month period was primarily as a result of the expense of $415 related to deferred financing fees associated with the original credit facility for the Fund which was amended in the second quarter of 2005 resulting in the settlement for accounting purposes of the original credit facility.

Interest Expense

Interest expense decreased by 26% in the three-month period and increased 27% twelve-month period ended December 31, 2006, respectively, when compared with the prior year periods. The substantial changes from the applicable periods were due to the implementation of a recapitalization of the Fund following the Ripon acquisition in June 2005. After funding the acquisition of Cogen Facilities under the Amended Credit Facility, the Fund's syndicate of lenders required that the Fund reduce its bank debt levels prior to the end of 2005 in accordance with terms of the previous credit agreement. As a result, the Fund obtained permanent financing in the form of a trust unit and Debenture offering in mid-November of 2005 (the "Offering") which reduced the Fund's bank debt and acquired and refinanced the Ripon project related debt on more favorable terms. Accordingly, interest expense decreased in the fourth quarter 2006 from the prior year period since the average debt outstanding was lower. In the twelve-month period ended December 31, 2006, interest expense increased as average debt outstanding for the full year 2006, when compared with 2005, was significantly higher as the Cogen Facilities'- acquisition- related bank and project debt was outstanding for only the second half of 2005.

During 2006, US $10,839 of the Debentures were exchanged into 1,186,731 Units, resulting in the principal amount of Debentures outstanding at December 31, 2006 of US $44,161.

Countryside Power Income Fund

DISTRIBUTIONS DECLARED TO UNITHOLDERS

	Three-month period ended December 31, 2006	Three-month period ended December 31, 2005	Year ended December 31, 2006	Year ended December 31, 2005 (as restated)
	$	$	$	$
Cash provided by operating activities	**3,903**	**3,145**	**20,430**	**16,772**
Add: Changes in working capital	876	2,205	2,159	2,162
Funds from operations before working capital changes	4,779	5,350	22,589	18,934
Add:				
Receipt of principal on USEB loans	175	476	1,684	1,828
Transaction costs expensed[1]	357	642	357	1,080
Deduct:				
Principal repayments on Cogen Facilities' project-related debt	-	-	-	957
Purchases of capital assets for regular operations[2]	310	128	670	504
Royalty Interest[3]	-	133	-	369
Distributable cash for the period	**5,001**	**6,207**	**23,960**	**20,012**
Distributions declared for the period	**5,382**	**4,674**	**20,738**	**16,145**
Weighted Average number of trust units outstanding				
– basic (thousands of trust units)	**20,730,576**	**17,316,670**	**19,968,697**	**15,513,147**
– diluted (thousands of trust units)	**26,461,700**	**23,338,532**	**25,647,228**	**21,535,009**
Distributable cash per trust unit for the period - basic	**0.241**	**0.358**	**1.200**	**1.290**
Distributions declared per trust unit for the period (whole dollars)	**0.259**	**0.271**	**1.035**	**1.041**

[1] During 2005, transaction costs related to the Ripon acquisition transaction and during 2006, related to the London Cogen project acquisition were paid to the Manager and advisors out of financing proceeds and were not operational in nature

[2] Purchases of capital assets for regular operations are non-expansionary capital expenditures. Total capital expenditures were as follows: in the three-month period ended December 31, 2006 - $1,613, for the three-month period ended December 31, 2005 - $65, in the twelve-month period ended December 31, 2006 - $3,399 and in the twelve-month period ended December 31, 2005 - $855.

[3] As the timing of the receipt of the royalty interest income earned in a period is dependent upon the timing and extent of equity distributions made by USEB to its shareholders', royalty interest income will only be included in the calculation of distributable cash when payments related to the royalty interest are received from USEB.

The Fund pays monthly cash distributions to Unitholders on or about the last business day of each month to Unitholders of record on the last business day of the prior month. The ex-distribution date is two business days prior to the last business day of the prior month. Distributions paid in 2006 amounted to $1.035 per trust unit per annum.

The Fund intends to meet future distribution payments from cash flow generated from its operating assets and cash on hand.

Countryside Power Income Fund

The composition of distributions paid by the Fund is approximately as follows:

Composition of Distributions paid by the Fund	% Return on Capital	% Return of Capital
2004	71	29
2005	66	34
2006	49	51

U.S. Resident Taxpayer Information

After consultation with its U.S. tax advisors, the Fund believes that its trust units more likely than not will be properly classified as equity in a corporation, rather than debt, for U.S. federal income tax purposes, and that distributions paid to its individual U.S. unitholders will more likely than not be qualified dividends. As such, the portion of the distributions made to U.S. individual unitholders that are considered dividends should qualify for the reduced rate of tax applicable to certain capital gains.

Composition of Distributions paid by the Fund	% Non-taxable	% taxable as "Qualified Dividend"
2004	27.1	72.9
2005	32.8	67.2
2006	35.0	65.0

This information is not meant to be an exhaustive discussion of all possible U.S. income tax considerations, but a general guideline and is not intended to be legal or tax advice to any particular holder or potential holder of trust units. Holders or potential holders of trust units should consult their own tax advisors as to their particular tax consequences of holding trust units. The Fund has not obtained a legal or tax opinion, nor has it requested a ruling from the IRS, on these matters.

LIQUIDITY AND CAPITAL RESOURCES

The Fund expects to be able to meet all of its obligations from cash flow from operations, cash on hand, interest and principal installments received on the USEB Allowed Secured Claim and its Amended Credit Facility. The Fund has $8,430 of cash on hand as at December 31, 2006. The Fund, through Countryside District Energy Corp. (as borrower) currently has total revolver and swing line credit commitments of approximately $45,000 and approximately $13,500 of loans outstanding under its Amended Credit Facility following the mandatory prepayment made on March 14, 2007 by the Fund in the amount of approximately $35,000, as a result of the receipt of the second installment from USEB which reduced the Allowed Secured Claim pursuant to the USEB Settlement Agreement. When including outstanding letters credit, swing line balances and guarantees, the Fund has available credit capacity of approximately $30,000 subject to ongoing loan compliance. This remaining unutilized commitment amount remains available for working capital purposes, including the ongoing funding for construction of the Countryside London Cogen project.

Cash used in investing activities was $1,715 in the twelve-month period ended December 31, 2006, due to repayments of $1,684 received by the Fund on the USEB loans offset by $3,399 in capital expenditures. Of the capital expenditures, $670 were operations related capital expenditures and of the remaining $2,729 the majority was related to plant upgrades, new customer connections at the PEI System, and expansion of the Fund's offices.

Net cash used in financing activities of $20,631 consists primarily of distributions to Unitholders and the repayment of the $2,000 swing line under the Amended Credit Facility, which fluctuates significantly based on daily cash flow requirements.

The decrease in cash during the twelve-month period is related to changes in working capital balances and capital expenditures.

Payments Due by Period

Contractual Obligations	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 Years
Long-term debt	$ 48,500	$ 48,500	$ -	$ -	$ -
Exchangeable debentures	50,308	-	-	-	50,308
Swing line of credit	674	674	-	-	-
Capital lease obligations	289	64	127	78	20
Operating leases	5,285	1,417	2,254	1,451	163
Total Contractual Obligations	**$ 105,056**	**$ 50,655**	**$ 2,381**	**$ 1,529**	**$ 50,491**

The Fund is in discussions with its lenders on obtaining a new or amended credit facility to support the Fund's ongoing liquidity and growth initiatives based on the expectation that the remaining proceeds to be received under the USEB Settlement Agreement will result in mandatory repayment of outstanding loans and the permanent reduction of the remaining credit commitment to nil on or before May 31, 2007 pursuant to the terms of the existing Amended Credit Facility.

According to the terms of the USEB Settlement Agreement, the Fund expects to receive a payment of approximately US $66,000 (or approximately $78 million based on a 1.17 exchange rate) on or before May 31, 2007. At the conclusion of the Fund's strategic review process, (see "Overview of Fund and Recent Developments – Fund's Strategic Review Process") the use of cash proceeds from USEB that remain after all loan balances have been fully repaid, unless otherwise agreed to by the lenders under Amended Credit Facility, will be determined with a view to the best interest of unitholders.

Countryside Power Income Fund

SUMMARY OF QUARTERLY OPERATIONAL RESULTS

	Three-month Period Ended March 31, 2005	Three-month Period Ended June 30, 2005	Three-month Period Ended September 30, 2005 *(as restated)*	Three-month Period Ended December 31, 2005
	Q1	*Q2*	*Q3*	*Q4*
Energy Volumes				
Sales of Steam (Mlbs)	171,842	72,222	180,926	240,084
Sales of Hot Water (MMBtus)	132,625	60,119	32,516	88,053
Sales of Chilled Water (MTon/hr)	136	915	1,593	268
Sales of Electricity (MWh)	292	171	133,393	103,830
Fuel Consumed (MMBtus)	436,099	223,442	1,498,207	1,887,829
Financial Indicators	$	$	$	$
Total Revenues	9,376	7,189	26,754	23,842
Adjusted EBITDA	4,427	3,145	7,256	6,486
Net income	3,020	891	3,294	4,039
Net income per trust unit (whole dollars)	0.20	0.06	0.22	0.24
Distributable cash	4,344	3,228	6,232	6,207
Distributions declared	3,819	3,820	3,832	4,674
Distributions per unit	0.256	0.256	0.257	0.259

	Three-month Period Ended March 31, 2006	Three-month Period Ended June 30, 2006	Three-month Period Ended September 30, 2006	Three-month Period Ended December 31, 2006
	Q1	*Q2*	*Q3*	*Q4*
Energy Volumes				
Sales of Steam (Mlbs)	324,825	228,968	204,819	227,381
Sales of Hot Water (MMBtus)	109,742	53,518	34,910	85,123
Sales of Chilled Water (MTon/hr)	115	784	1,393	315
Sales of Electricity (MWh)	106,583	139,176	120,830	120,916
Fuel Consumed (MMBtus)	1,508,711	1,611,029	1,408,976	1,500,178
Financial Indicators	$	$	$	$
Total Revenues	22,263	22,560	24,963	22,672
Adjusted EBITDA	7,985	7,555	9,613	5,137
Net income	2,439	5,564	3,177	1,624
Net income per trust unit (whole dollars)	0.12	0.28	0.16	0.08
Distributable cash	6,307	5,907	6,707	5,001
Distributions declared	5,083	5,088	5,185	5,382
Distributions per unit	0.259	0.259	0.259	0.259

The Cogen Facilities would normally be expected to be most profitable in the third quarter when capacity payments under the power purchase agreements are at their highest. While the first quarter of the calendar year is generally the most profitable quarter for the District Energy Systems, as it represents the primary heating season, the second and third quarters are generally the weakest quarters due to warmer temperatures, which result in lower demand for thermal energy by customers.

All of the indicators outlined above have been significantly impacted by the acquisition of the Cogen Facilities beginning with the third quarter ended September 30, 2005. The third quarter of 2005 was the first period during which the Cogen Facilities' energy volumes and financial results were incorporated into those of the Fund, and the quarter included the full quarter of the Cogen Facilities' results. This makes the comparability of quarters before and after the acquisition of the Cogen Facilities on June 29, 2005 less meaningful.

For financial reporting purposes, revenues and expenses earned and paid in US dollars are consolidated into the Fund's results at the prevailing market foreign exchange rates, which can cause significant differences when comparing results of the Fund on a quarterly basis, given the significant contribution to overall results of the Cogen Facilities segment.

District Energy System energy volumes and sales are seasonal, with a majority of energy volumes, sales and earnings occurring during the winter heating season and typically lower results during spring and fall when less heating is required by customers. Sales of steam and hot water are greatest during the winter heating season in the first quarter and the fourth quarter, while sales in the summer quarters, the second and third quarters, are much lower in terms of revenue earned. The Cogen Facilities' sales are also seasonal. The majority of the Cogen Facilities' earnings occur during the summer quarters, the second and third quarters and results are lower during the winter season when electrical capacity revenues are lower.

Although adjusted EBITDA and net income will generally follow a seasonal pattern, net income may be significantly affected by unrealized gains and losses on derivative instruments and foreign exchange.

Prior to the third quarter of 2005, the variance in revenue between quarterly periods was due primarily to the commencement of the winter heating season in the three-month period ended December 31, 2004. The Cogen Facilities contributed much of the increases in sales volumes and fuel consumed beginning in the third quarter of 2005.

FINANCIAL INSTRUMENTS

Interest Rate Swap

During December 2005 one of the Fund's indirect subsidiaries entered into an interest rate swap agreement with a Schedule I bank to fix the interest rate paid on $47,000 of its long-term debt at a current rate of 3.87%. As of March 15, 2007, the interest rate swap was settled between the parties and the Fund received approximately $209. The favourable settlement was a result of the concurrent mandatory prepayment of the outstanding loans under the Amended Credit Facility following receipt of the second installment from USEB to repay the Allowed Secured Claim pursuant to the USEB Settlement Agreement.

Foreign Exchange

Substantially all of the District Energy System's operations and earnings are in Canadian dollars. Prior to the USEB Bankruptcy filing, the USEB loan was denominated in Canadian dollars and the interest was fixed at 11.0% per annum, which mitigated the foreign exchange and revenue volatility risk of the Fund, respectively. The USEB Allowed Secured Claim is denominated in the U.S. dollars and therefore, the foreign exchange risk has been transferred to the Fund. The operations and earnings of the Cogen Facilities are in US dollars. The Fund has capital-related obligations in the form of interest payments on the Debentures, as a result of the acquisition of Ripon Power. Of the annual US dollar cash flow from the Cogen Facilities that is expected to meet those obligations, as of December 31, 2006, approximately US $2,800 is naturally hedged through the fixed interest coupon related to the US dollar denominated Debentures issued through Countryside Canada.

Approximately US $5,300 of annual cash flow from the Cogen Facilities, all or a portion of which is expected to be used to meet Canadian dollar denominated debt service obligations and anticipated monthly unitholder distributions, is hedged using Canadian dollar, monthly "knockout" call option contracts which have an exercise price of US $0.89 per Canadian dollar. The Fund has purchased thirty-six consecutive monthly call option contracts at the same exercise price until December 2008. To the extent that the US/Canadian dollar exchange rate reaches US $0.84 (the "Knockout Price") at anytime while option contracts are still in effect, the remaining unexpired monthly call option contracts will immediately expire. When the US dollar exchange rate reaches $0.89 or higher, the Fund has the right to exercise the call option and fix the exchange rate at $0.89. The parameters related to the call options and currency hedge described above have the effect of limiting the Fund's risk to foreign exchange fluctuation between $0.84 and $0.89 on US $5,300 annually for the remaining two year period.

The call option contracts were entered into with a Schedule 1 bank during December of 2005 at a cost of US $188.

RISKS AND UNCERTAINTIES

USEB Bankruptcy Risk

On November 29, 2006, USEB and substantially all of its subsidiaries filed a petition for reorganization under Chapter 11 of the US Bankruptcy Code. At the time of such filing, USEB alleged, among other things, that the USEB Loan was "unjustifiably onerous" and that it intended to initiate proceedings to void or restructure the

USEB Loan as well as obtain other relief. The Fund disputed USEB's allegations and stated its intention to move to dismiss the bankruptcy case on the ground it was filed in bad faith. On January 13, 2007, the parties reached a settlement agreement. For details of the USEB Settlement Agreement see "Recent Developments – USEB Bankruptcy Filing and Settlement". On February 1, 2007, the Bankruptcy Court stated it would approve the USEB Settlement Agreement subject to review and approval of the final documentation. On February 16, 2007 the Bankruptcy Court entered a formal order approving the USEB Settlement Agreement (the "Approval Order") and on February 26, 2007, the Approval Order became final an non-appealable. The USEB Settlement Agreement became effective on March 7, 2007.

In addition to scheduled interest payments, Countryside Canada has received US$33 million in payment pursuant to the USEB Settlement Agreement leaving the balance of US$66.4 million to be paid on or before May 31, 2007. USEB's ability to pay the balance of the Allowed Secured Claim on or before maturity will depend on its ability to consummate an exit financing within such time frame. The success of such a financing can depend on many factors which are beyond the Fund's control including the capital market conditions, the financial and operational performance of USEB, events in USEB bankruptcy proceedings, completion of satisfactory due diligence by potential funding parties, negotiation and completion of definitive documentation by USEB and the potential funding parties and the actions by third parties. Accordingly there can be no assurance that USEB shall consummate an exit financing sufficient to pay the entire Allowed Secured Claim on or before May 31, 2007.

In the event USEB does not pay the full Allowed Claim on or before May 31, 2007, Countryside Canada may, among other things, seek to enforce its rights under the Allowed Secured Claim (including enforcement actions as to the collateral) or sell the Allowed Secured Claim. There can be no assurance that the Fund will realize the full value of the Allowed Secured Claim under any of these courses of action.

Amended Credit Facility

The USEB bankruptcy filing and USEB's payment default under the Amended Credit Facility caused a cross-default under the USEB Loan. The Fund has negotiated a waiver under which the lending syndicate has agreed to waive such cross-defaults through May 31, 2007. There can be no assurances that the lenders will agree to extend such waiver beyond such date, particularly if there are adverse changes in the business or financial condition of the Fund during such period. For this reason, the Fund is seeking a new or amended credit facility as well as other strategic alternatives. If the lenders do not extend such waiver beyond May 31, 2007 that would prevent the Fund from continued access to the Amended Credit Facility, the Fund may encounter liquidity problems absent the receipt of any further installments from USEB pursuant to the USEB Settlement Agreement. If the lenders enforce their rights under the Amended Credit Facility, the Fund will be required, among other things, to suspend unitholder distributions and funding of the London Cogeneration Project.

Risks Related to Operations

The District Energy Systems' ability to deliver steam, hot water and chilled water to its customers is the main factor for determining the Fund's cash available for making distributions to unitholders and debt service obligations from such facilities. Likewise, the Cogen Facilities' ability to deliver electricity and steam to their customers is the main factor for determining the Fund's cash available for making distributions to unitholders and debt service obligations from such facilities. If operations are interrupted at the Fund's operating facilities or USEB due to mechanical failure, lack of fuel supply or for other reasons, it could have a negative effect on distributable cash to unitholders and other stakeholders. USEB's Renewable Projects' ability to generate and deliver to its customers electricity and biogas (as applicable) on a daily basis and at certain expected levels is the main factor in determining the cash available for interest payments due to Countryside Canada from USEB pursuant to the USEB Settlement Agreement.

The amount of energy generated by the London System is dependent on the availability of natural gas fuel which may be subject to adverse changes beyond the control of the Fund. Likewise, the amount of energy generated by the PEI System is dependent on the availability of a suitable supply of wood waste and municipal solid waste which may be subject to adverse change for reasons beyond the control of the Fund.

The Cogen Facilities use natural gas for fuel. The Cogen Facilities currently purchase natural gas through purchase contracts with Sempra which expire on March 31, 2008. When such contracts expire or are terminated, there can be no assurance that the Cogen Facilities will enter into new long-term gas contracts or otherwise purchase natural gas in the market on the same basis as the current contracts. Further, the prices which the Cogen

Facilities currently pay for natural gas correlate with the energy prices which the Cogen Facilities receive under its PPA's. The energy prices received under the PPA's are in turn based on the respective utilities' full short run avoided costs, commonly referred to as Short Run Avoided Cost or "SRAC". The Ripon PPA and the San Gabriel PPA do not expire until 2018 and 2016 respectively. The SRAC rates are the subject of a pending regulatory proceeding and may be modified. (See "Risks and Uncertainties – Electricity Pricing"). In the event SRAC rates are modified in a manner which creates a discontinuity between the Cogen Facilities' gas costs and energy prices, operating margins at the Cogen Facilities may be reduced in turn reducing the Fund's distributable cash.

The amount of energy produced by USEB's Renewable Projects depends on the extraction and availability of biogas from public and privately owned landfills. The quantity of biogas available and the ability to collect it is determined by numerous factors which are beyond the control of USEB and which cannot be predicted with certainty.

Electricity Pricing

The Cogen Facilities sell power pursuant to two long term PPAs which provide for capacity payments (which are substantially fixed) and energy payments, which generally are based on utilities' full SRAC as determined by the CPUC. Under the PPAs, the Cogen Facilities' ongoing ability to receive the full firm capacity payment and capacity bonus payments is conditioned upon the delivery of the contract capacity during on-peak hours during the summer peak months May through October for the Ripon Facility and June through September for the San Gabriel Facility subject to certain terms and conditions. Any adverse change in capacity and/or capacity bonus payments may negatively impact the Cogen Facilities' cash flow which in turn may negatively impact the Fund's distributable cash.

The Cogen Facilities receive energy payments which generally are based on the utilities' full SRAC as determined by the CPUC. The authority to modify the elements of the SRAC energy price formula rests with the CPUC, subject to certain statutory requirements imposed by the Electric Utility Industry Restructuring Act (Assembly Bill 1890). There is an open proceeding in which the CPUC has indicated it will review the SRAC pricing for possible prospective changes. There can be no assurance that any change in the SRAC price methodology will not adversely affect the operating margins derived by the Cogen Facilities from the PPAs and, consequently, the Fund's distributable cash.

Furthermore, the Cogen Facilities' PPAs terminate in 2018 (Ripon) and 2016 (San Gabriel). There is no assurance that upon expiry of such PPAs, the Fund's subsidiaries will be able to enter into new PPAs or otherwise sell their power into the market at prices at or above projected levels. Future prices and rates cannot be predicted with certainty and will inevitably deviate from such forecasts and such deviation may be material.

Currently, a majority of the off-takers of USEB's Renewable Projects are contractually obligated to purchase electricity under long-term PPAs. Should any of the long-term contracts terminate or expire, USEB will be required to either re-negotiate with existing off-takers, negotiate new PPAs with new off-takers, or sell electricity into the electricity wholesale market or spot market, in which case the prices for electricity will depend on prevailing market conditions. Under the proposed settlement between USEB and the State of Illinois, USEB's Illinois-based projects shall withdraw from the retail rate incentive program effective May 31, 2007. If such settlement is consummated and such withdrawal occurs, it is expected that the projects will seek to negotiate new contracts in the wholesale and green power markets based on rates prevailing in those power markets at the time. USEB's ability to consummate a successful exit financing may be affected by USEB's ability to negotiate new contracts and/or prospective conditions in the green power wholesale market.

Significant declines in prices and rates would be expected to have a material adverse impact on USEB and/or Cogen Facilities as applicable. While the Manager believes that strategies exist to mitigate, at least in part, the adverse effects of such price declines, there is no assurance such strategies will be available or implemented successfully.

Foreign Currency Fluctuations

A majority of the Fund's costs and its financial obligations to its lenders and unitholders are denominated in Canadian dollars. It's obligation to Debenture holders is denominated in US dollars.

Under the USEB Settlement, the USEB loan, formerly denominated in Canadian dollars and the USEB royalty, formerly denominated in US dollars, are now in the form of the remaining Allowed Secured Claim denominated in US dollars. Accordingly, the value received by the Fund from interest payments and principal repayments respecting such Allowed Secured Claim under the USEB Settlement is subject to fluctuations in the US dollar/ Canadian dollar exchange rate. The Fund is continuously monitoring the foreign exchange rates and will consider entering into hedging contracts to mitigate this risk if it deems appropriate. Due to the expected near term maturity of the remaining balance of the Allowed Secured Claim in May 2007, the Fund does not believe it is necessary to enter into a hedge against foreign exchange fluctuations at this juncture in light of current exchange rates.

The Cogen Facilities' revenues derived from PPAs and steam sale agreements are denominated in US dollars as is the expected resultant US dollar denominated distributable cash from the Cogen Facilities. The Manager has entered into a foreign exchange option to mitigate the effect of the resultant foreign exchange risk related to the portion of US dollar revenues required to meet its Canadian dollar obligations and anticipated unitholder distributions as outlined under the section "Financial Instruments - Foreign Exchange".

Interest Rate and Debt Repayment Risk

At present, the Fund's Amended Credit Facility bears interest at a variable rate based on short-term Canadian banker's acceptances and Canadian prime rates. An increase in short-term interest rates, if unhedged, could affect the Fund's ability to pay interest on outstanding balances under the Amended Credit Facility and distributions to unitholders.

The Fund has US$44,161 of Debentures outstanding which bear interest at a fixed coupon rate of 6.25% and are payable in US dollars. A decrease in revenues earned or an increase in expenses incurred by the Cogen Facilities could affect the Fund's ability to pay interest to holders of the Debentures.

With regard to debt repayment risk, there can be no assurance that the Fund will have sufficient capital or be successful in refinancing the Amended Credit Facility or the Debentures when they mature.

Tax Related Risks

There can be no assurance that Canadian federal income tax laws and administrative policies respecting the treatment of mutual fund trusts will not be changed in a manner that adversely affects the holders of Units. If the Fund ceases to qualify as a "mutual fund trust" under the Tax Act, the income tax considerations described herein would be materially and adversely different in certain respects, including that the Units may cease to be qualified investments. The Tax Act imposes penalties for the acquisition or holding of non-qualified investments.

On October 31, 2006, the Department of Finance (Canada) announced the "Tax Fairness Plan" whereby the income tax rules applicable to certain publicly listed trusts and partnerships will be significantly modified. In particular, certain income of (and distributions made by) these entities will be taxed in a manner similar to income earned by (and distributions made by) a corporation. These proposals will be effective for the 2007 taxation year with respect to trusts which commence public trading after October 31, 2006, but the application of the rules will be delayed to the 2011 taxation year with respects to trusts which were publicly listed prior to November 1, 2006 (although the announcement suggested that this transitional relief could be lost under certain circumstances, including the "undue expansion" of an income trust). On December 21, 2006, the Department of Finance issued for public comment the draft legislation to implement these proposals. There is no assurance that the draft legislation will be enacted in the manner proposed or at all.

On December 15, 2006, the Department of Finance (Canada) released guidance for income trusts and other flow-through entities that qualify for the four-year transitional relief. The guidance establishes objective tests with respect to how much an income trust is permitted to grow without jeopardizing its transitional relief. In general, the Fund will be permitted to issue new equity in each of the next four years equal to the great of $50 million and a certain percentage of the Fund's market capitalization as of the end of trading on October 31, 2006 (up to 100% percent over the four years). This latter amount is cumulative to the extent it is not used in a given year and, accordingly, the Fund will be permitted to issue new equity over the next four years at least equal to its October 31, 2006 market capitalization (subject to the applicable annual limits). Market capitalization, for these purposes, is to be measured in terms of the value of the Fund's issued and outstanding publicly-traded units. If these limits are exceeded, the Fund may lose its transitional relief and thereby become immediately subject to the proposed rules.

The Fund is considering these announcements and the possible impact of the proposed rules to the Fund. The proposed rules (including the guidance released on December 15, 2006) may adversely affect the marketability of the Fund's units and the ability of the Fund to undertake financings and acquisitions, and, at such time as the proposed rules apply to the Fund, the distributable cash of the Fund may be materially reduced.

Currently, a trust will not be considered to be a mutual fund trust if it is established or maintained primarily for the benefit of non residents unless all or substantially all of its property is property other than taxable Canadian property as defined in the Tax Act. On September 16, 2004, the Minister of finance (Canada) released draft amendments to the Tax Act. Under the draft amendments, a trust would lose its status as a mutual fund trust if the aggregate fair market value of all units issued by the trust held by one or more non-resident persons or partnerships that are not Canadian partnerships is more than 50% of the aggregate fair market value of all the units issued by the trust where more than 10% (based on fair market value) of the trust's property is taxable Canadian property or certain other types of property. If the draft amendments are enacted as proposed, and if, at any time, more than 50% of the aggregate fair market value of units of the Fund were held by non-residents and partnerships other than Canadian partnerships, the Fund would thereafter cease to be a mutual fund trust. The draft amendments do not currently provide any means of rectifying a loss of mutual fund trust status. On December 6, 2004, the Department of Finance tabled a Notice of Ways and Means Motion which did not include these proposed changes. The Department of Finance indicated that the implementation of the proposed changes would be suspended pending further consultation with interested parties. The issue of ownership of units of mutual fund trusts by non-resident persons and partnerships other than Canadian partnerships was not addressed in the December 21, 2006 proposals.

There can be no assurance that the Units will continue to be qualified investments under the Tax Act. The Tax Act currently imposes penalties for the acquisition or holding of non-qualified investments.

Income fund structures generally involve significant amounts of inter company or similar debt, generating substantial interest expense, which serves to reduce earnings and therefore income tax payable. There can be no assurance that taxation authorities will not seek to challenge the amount of interest expense deducted. If such a challenge were to succeed against Countryside Canada, or Countryside US Holding, it could materially adversely affect the amount of cash available to the Fund for distribution to Unitholders or available to Countryside Canada to make interest payments on the Debentures. The Manager of the Fund believes that the interest expense inherent in the structure of the Fund is supportable and reasonable in light of the terms of the Countryside Canada Notes, the Debentures and the Countryside US Holding Note. On October 31, 2003 the Department of Finance released, for public comment, proposed amendments to the Tax Act that relate to the deductibility of interest and other expenses for income tax purposes for taxation years commencing after 2004. In general, the proposed amendments may deny the realization of losses in respect of a business if there is no reasonable expectation that the business will produce a cumulative profit over the period that the business can reasonably be expected to be carried on. The Fund has advised counsel that it does not believe that the proposed amendments will have a material affect on the tax position of the Fund or Countryside Canada. As part of the 2005 Federal Budget, the Minister of Finance (Canada) announced that an alternative proposal to replace the proposed amendment would be released at an early opportunity.

Further, interest on the Countryside Canada Notes accrues at the Fund level for Canadian federal income tax purposes whether or not actually paid. The Declaration of Trust provides that an amount equal to the taxable income of the Fund will be distributed each year to Unitholders in order to reduce the Fund's taxable income to zero. Where interest payments on the Countryside Canada Notes are due but not paid in whole or in part, the Declaration of Trust provides that additional Units must be distributed to Unitholders in lieu of cash distributions. Unitholders will generally be required to include an amount equal to the fair market value of those Units in their Canadian federal taxable income, in circumstances when they do not directly receive a cash distribution.

Countryside District Energy's tax liability is currently reduced by tax loss carry-forwards. Should the taxing authorities reduce or eliminate such tax loss carry forwards, Countryside District Energy's tax liability may increase and adversely impact distributable cash.

Regulatory and Legislative Risk

The Fund's District Energy Systems, USEB's Renewable Projects and the Cogen Facilities must be licensed to comply with energy, operational, environmental, and safety statutes, standards, orders and regulations enacted by legislative bodies and imposed by regulatory bodies. Although the Fund believes that all such facilities are in compliance in all material respects with such statutes, permits, standards, orders, variances and regulations, failure to operate the facilities in compliance with such statutes, permits standards, orders and regulations may require temporary or permanent cessation of operations of the facilities and may expose owners and operators to claims and clean-up costs. Any new law or regulation could require significant new expenditures to achieve or maintain compliance.

In May 2006, the Ripon Facility performed a diagnostic test which revealed that its auxiliary boiler could not be operated in compliance with its operating permits at all load conditions. Since that date the Ripon Facility has received variances from the San Joaquin Valley Unified Air Pollution Control District (the "San Joaquin District") which, among other things, permit the Ripon Facility to operate the auxiliary boiler with excess NOx and CO emissions subject to certain conditions. The current variance expires on the earlier of October 31, 2007 or when the subject boiler achieves compliance with the permitted emissions limit whichever comes first. Ripon Cogeneration is currently exploring different methods of achieving compliance including equipment modifications and permit modifications. The auxiliary boiler is used to provide steam to Fox River, in conformance with the requirements of the steam agreement, when the Ripon Facility gas turbine is not operating. If the auxiliary boiler cannot run, Ripon Cogeneration plans to operate the gas turbine.

From time to time, Ripon Cogeneration has received notices of violation ("NOV's") from the San Joaquin District respecting alleged violations of applicable laws and permits. Such NOV's do not allege excess emissions but mainly relate to data collection and reporting. Ripon Cogeneration has settled certain of the NOV's for immaterial sums and intends to contest or resolve the pending NOV's on terms which are not expected to be materially adverse to the Fund. Ripon Cogeneration is in the process of upgrading its data collection equipment. The Manager believes such upgrade will address the compliance issues raised by the NOV's on a long-term basis.

Qualifying Facility and Qualifying Solid Waste Energy Facility Status

The Cogen Facilities and the majority of USEB's facilities are QFs under the Public Utilities Act of 1978 as amended ("PURPA") as implemented by the Federal Energy Regulatory Commission ("FERC"). Loss of QF status could trigger defaults under covenants to maintain QF status under the PPAs and debt agreements and result in PPA termination, penalties or acceleration of indebtedness under such agreements plus interest. Further, under PURPA, a regulated utility could refuse to purchase electricity from the facility(ies) at such utility's avoided cost if QF status were lost and may be entitled to certain remedies for breach of an existing PPA including the right to terminate the PPA. In addition, the FERC has asserted jurisdiction over the rates charged by QFs during periods when a facility does not operate in compliance with the applicable QF criteria and has indicated its willingness to order the refund of payments previously made under PPAs in some cases. Further, loss of QF status could expose either Facility to regulation by FERC under the Federal Power Act, by the CPUC Commission under the Public Utility Holding Company Act. Additionally if one of USEB's Illinois facilities lost QF status, it may lose QSW status (as defined below) under the Illinois Public Utilities Act.

Any of these consequences would result in substantial regulatory burdens, potentially lower revenues from power sales and potentially insurmountable impediments to affected entities with regard to conducting business in the manner currently contemplated. Accordingly, the Cogen Facilities ability to generate distributable cash as well as the ability of USEB's facilities to generate cash and/or consummate a refinancing to make payments under the USEB Allowed Claim is dependent on their maintaining QF status. A facility may lose its QF status either temporarily or permanently.

On August 8, 2005, comprehensive energy legislation was enacted when the President of the United States signed into law EPA 2005, including several changes to PURPA. On February 2, 2006, the FERC issued its Order No. 671 promulgating new regulations to reflect the changes in PURPA made by EPA 2005.

Most of the changes to PURPA made by EPA 2005 and the FERC's Order No. 671 will apply only to new cogeneration facilities and, therefore, will not affect the Cogen Facilities or USEB's facilities at least for as long as the thermal output of the facilities is sold to the existing steam hosts. If any such facilities should lose QF status and if it should be determined that the purchasing utility has the right to terminate its PPA as a result thereof, the provisions of EPA 2005 and the new FERC regulations promulgated there under may apply to any new PPA entered into under PURPA for any of the facilities. In Order No. 671, the FERC eliminated the exemption from rate regulations under Sections 205 and 206 of the Federal Power Act for sales of electricity made by qualifying facilities other than pursuant to a State regulatory authority's implementation of PURPA. As a result, should electricity be sold from either of the Cogen Facilities other than pursuant to their existing PPAs, the contract or tariff pursuant to which the electricity is sold will have to be filed with, and accepted for filing by, the FERC.

Certain of USEB's Renewable Projects in Illinois receive certain benefits and exemptions because each is a Qualified Solid Waste Energy Facility ("QSW Status") under the Retail Rate Law of the Illinois Public Utilities Act (the "Retail Rate Law"). Under the proposed settlement with the State of Illinois, USEB's Illinois-based projects are to withdraw from the Retail Rate Law program effective May 31, 2007. If such settlement is consummated, risks formerly associated with loss of QSW status shall no longer affect the Fund.

If such settlement is not approved or consummated, the State of Illinois may seek leave from the Bankruptcy Court to revoke such projects' QSW Status. If any of USEB's Illinois Renewable Projects were to lose its QSW status, the facility would no longer be entitled to the benefits of the Retail Rate Law. In such event the applicable Illinois utility may no longer be required to purchase electricity from the relevant projects at the rates provided for in the Retail Rate Law. Under certain circumstances, loss of QFW Status on a retroactive basis could lead to, among other things, claims by the utility customers for a refund of payments already made.

Further, such facilities may lose all or some of such benefits if PURPA or the Illinois Public Utilities Act (or the regulations or orders promulgated there under) were repealed or modified or if any court or regulatory body adopted a new interpretation of such statute, regulation or order or if a court or regulatory body determined that an Illinois Renewable Project violated a statute, regulation or order. From time to time, legislation modifying the Illinois Public Utility Act has been proposed. If certain of the introduced legislation had been enacted in its proposed form, it would reasonably be expected to have a material adverse effect on the QSWEFS. To date such legislation has not been enacted; however there can be no assurance that such legislation will not be enacted in the future. If USEB does not consummate its settlement with the the State of Illinois, any of these events could have a material adverse effect on USEB's ability to generate cash and/or consummate a take out refinancing to make payments under the USEB Allowed Claim or on the Fund's ability to fully realize on the Allowed Claim if such take out financing is not consummated.

<u>Potential Cogen Facilities' Refund Liability</u>

A proceeding is currently pending before the CPUC in Docket No. R 99-11-022 in which the CPUC is considering whether to apply retroactively for the period December, 2000 through March, 2001 a March, 2001 decision (D. 01-03-067) which, among other things, modified the methodology used in calculating SRAC and thereby decreased SRAC levels for the period commencing March 27, 2001. In September, 2002, the California Court of Appeals found that the CPUC had violated PURPA for failing to consider SCE's argument that the CPUC should retroactively apply the modified SRAC formula. Southern Cal. Edison vs. Public Utilities Comm'n., 101 Cal. App. 4th 982 (2002). The Court of Appeals directed the CPUC to consider SCE's request. In February, 2005, a Draft Decision was issued by the assigned Commissioner who found that "evidence shows SRAC prices were correct between December 2000 and March 2001, and retroactive application of the modified SRAC formula is not warranted". Various parties have submitted comments on the Draft Decision, including PG&E, SCE, a ratepayer organization and the CPUC's Office of Ratepayer Advocates, objecting to the Draft Decision. The CPUC has not yet issued a final decision in the matter and is free to accept the Draft Decision as written, modify it or reject it in its entirety. The outcome of this proceeding cannot be predicted. Even in the event of an adverse CPUC decision, the Manager has been advised by counsel that the Cogen Facilities would have several meritorious legal defenses that would be available to protect the Cogen Facilities from any material adverse impact. However, there is no assurance that the Cogen Facilities would prevail on such defenses if called upon to assert them. If the CPUC ultimately adopts a final order imposing a retroactive modification to the SRAC formula, and a remedy based thereon is ordered or authorized, and if such final order and remedy is not reversed on appeal or otherwise enjoined, QFs including the Ripon and San Gabriel Facilities could be required to make refunds and/or accept reduced payments (by way of offset of past overpayment against future payments for power delivered) under their respective PPAs. Such refunds or reduced payments could materially and adversely affect the Cogen Facilities' ability to generate distributable cash.

Potential Cogen Facilities' Steam Host Termination for Convenience

Both steam hosts at the Cogen Facilities are permitted to terminate their respective steam sales agreements for convenience under certain circumstances. Each steam sales agreement provides that, in such event, the steam customer must make a specific monetary payment to the Cogen Facilities to cover their cost of obtaining a replacement steam host. The San Gabriel Facility's steam host's obligation to make such payment terminates after the twelfth year of the steam sale agreement. Such steam host may also discharge its obligation by obtaining a replacement steam host. It is possible that either steam host may exercise such termination right but fail to comply with its obligations to obtain or fund the cost to obtain a replacement steam host due to lack of resources or for other reasons. In such event the Cogen Facilities may not have an adequate remedy against the steam host and be required to obtain a replacement steam host at its own expense or probably lose its QF status. Loss of QF Status would have a material adverse effect on the Cogen Facilities.

On March 7, 2007, Blue Heron Paper Company ("Blue Heron") announced that it had issued a plant closing warning to its employees at the paper mill which serves as the Steam Host for the San Gabriel Facility. In the announcement, Blue Heron claimed that the potential closing was due to shrinking margins caused by recently increasing waste paper costs and decreasing newsprint prices. At this juncture, it is uncertain whether the mill will close. A mill closing may have a material adverse effect on the San Gabriel Facility's QF Status unless alternative steam sales arrangements are made. The Manager is currently exploring various measures to mitigate against any such adverse effect including alternative arrangements with Blue Heron that would protect the San Gabriel Facility's QF even if the paper mill ceases or suspends its current operations. Under the steam sales agreement, Blue Heron is required to purchase a minimum volume of steam annually from the San Gabriel Facility and is liable for costs associated with replacing Blue Heron as a steam customer to preserve the San Gabriel Facility's QF status, up to a limit in excess of $4,000. Subject to preservation of QF status, the adverse effect of a mill closing on the Fund would not be expected to be material. See "Risk and Uncertainties" – Qualifying Facility and Qualifying Solid Waste Energy Facility Status".

Reliance on Third Parties and Potential Conflicts of Interest

Pursuant to the Management Agreement and the Administration Agreement, commencing on November 1, 2005 the Fund and its subsidiaries will rely substantially on the Manager and its Canadian subsidiary for management, administration and project development functions. (See "Transactions with Related Parties – Management Agreement and Administration Agreement"). There may be circumstances in which the interests of the Manager, its affiliates or entities managed by such parties may conflict with those of the Fund, Countryside Canada, its subsidiaries and the Unitholders. Although the Manager's senior executives are required to devote a significant majority of their time for the benefit of Countryside Canada, Countryside US Holdings and its subsidiaries and to the development of projects reasonably expected to be within the acquisition criteria of the Fund, the Manager's personnel are not required to devote their time exclusively to these activities. Further, while the Manager is prohibited from providing management and administrative services to third parties other than the Fund, the Manager may develop and own energy and utility infrastructure projects for its own account or jointly with third parties, subject to its obligation to provide the Fund with a first opportunity to invest in such projects. Thus, subject to the constraints described above, the Manager and its senior executives may engage in activities similar to the current activities of the Fund, Countryside Canada and its subsidiaries.

The Manager and its affiliates, however, will provide Countryside Canada and its subsidiaries with the first opportunity to invest in any entity or asset that meets the investment criteria of the Fund and Countryside Canada that the Manager or its affiliates develop, own or control. The Manager shall only be free to offer such investment opportunities to third parties or to pursue them for its own account if Countryside Canada or its subsidiaries decline or are unable to pursue such opportunities.

Circumstances may arise where the Fund trustees or members of the board of directors of a corporation in which the Fund has invested are directors or officers of corporations that compete with the interests of the Fund. No assurances can be given that opportunities identified by such persons will be provided to the Fund or an entity in which the Fund has invested.

Further provisions in the Declaration of Trust, which are similar to those contained in the Canada Business Corporations Act, provide certain procedures to be followed in the event of such conflicts of interests, and certain remedies may be available to the Fund where such procedures are not followed.

The Fund is reliant upon USEB with respect to the administration and operations management of the USEB Renewable Projects. The Cogen Facilities are partially reliant on independent contractors for the day to day operational and asset management of the facilities.

London Cogeneration Project

On October 16, 2006, the Ontario Power Authority (the "OPA") and Countryside London Cogen entered into a Combined Heat and Power Contract ("CHP Contract") respecting the development, operation and sale of electricity from a to-be-built 17 MW (nameplate) gas cogeneration plant located in London Ontario (the "London Cogeneration Facility"). The CHP Contract has a term of 20 years commencing on the London Cogeneration Facility's commercial operation date. Countryside London Cogen is obligated to design, build and operate the London Cogeneration Facility in accordance with the Agreement and applicable laws, codes, rules and industry practices.

Countryside London Cogen is required to commence commercial operation (as defined in the CHP Contract) by June 1, 2008 (the "Commercial Operation Date"), failing which the Countryside London Cogen is subject to liquidated damages in accordance with a formula set forth in the OPA Contract. The Commercial Operation Date may be adjusted for force majeure. The maximum exposure to Countryside London Cogen under this provision would be approximately $1 million.

In addition, if the commercial operation date does not occur within one (1) year after such date, then such failure would permit the OPA to terminate the CHP Contract unless Countryside London Cogen has paid all liquidated damages accruing to the one year date and provided the full amount of the required completion and performance security. The failure to reach the commercial operation date within eighteen (18) months after the commercial operation milestone would be considered an event of default giving rise to the right of Countryside London Cogen to terminate the CHP Contract and sue for damages.

Countryside London Cogen has provided completion and performance security to the OPA of $602 upon which the OPA may draw to satisfy any damage claims. Countryside London Cogen is obligated to replenish any amounts drawn upon.

The profitability of the CHP Contract for Countryside London Cogen will be reduced to the extent Countryside London Cogen operates at less than the capacity or efficiency contained in its bid or with higher O&M costs contained in its bid.

There are events of default for both Countryside London Cogen and the OPA. These additional events of default include: a cross-default provision (default by Supplier of financial obligations to a third party); failure to meet the commercial operation date; failure to meet the availability requirements; capacity check requirement failures; and performance security failures subject to cure provisions.

For certain Countryside London Cogen events of default, the OPA is entitled to levy a performance assessment set-off, as liquidated damages equal to three (3) times the average Contingent Support Payment (as defined in the OPA Contract) payable to Countryside London Cogen for the most recent twelve (12) months where there has been three (3) or more Countryside London Cogen events of default within a contract year regardless of whether such events had been subsequently cured.

The development of the London Cogeneration Facility is subject to risks normally associated with development projects of this type including construction and equipment procurement delays, cost-overruns, permitting, labour disruptions, fuel procurement, interconnection issues etc. However Countryside London Cogen has sought to mitigate the risks by entering into a fixed price engineering, procurement and construction contract with Meccon London Inc. backed by performance and payment bonds. In addition, material land use and air and noise emissions permits have been obtained. Nonetheless there are no assurances that the London Cogeneration project will be completed on time or on budget and without any additional exposure to Countryside London Cogen.

Other Risks

For a more detailed discussion of risk factors, reference should be made to the 2005 Annual Information Form and the 2006 Annual Information which shall be filed on or before March 30, 2007, as well as the Prospectus of the Fund and Countryside Canada filed with securities regulators on November 8, 2005 pages 55 to 65 which are incorporated by reference and filed on www.sedar.com.

TRANSACTIONS WITH RELATED PARTIES

Development Agreement with Cinergy and USEY

Countryside U.S. Power, a subsidiary of Countryside Canada, entered into a Development Agreement with an indirect subsidiary of Cinergy and USEY under which, subject to its terms and conditions, the Cinergy subsidiary and USEY contributed their experience and financial resources to the acquisition, development, improvement and operation of energy projects that they choose to pursue and that will meet the Fund's investment and growth objectives. Countryside U.S. Power, through service provided by the Manager, provided investment analysis and evaluation services on behalf of all parties to the agreement. In consideration for these services, Countryside U.S. Power was to be paid an annual fee of approximately US $440 for 2006 from an indirect subsidiary of Cinergy and USEY.

Pursuant to the USEB Settlement Agreement, the obligation for USEY to pay development fees to Countryside U.S. Power and Countryside U.S. Power's obligation to provide services to USEY has been terminated.

Management Agreement

The Fund entered into a management agreement dated September 23, 2005, between subsidiaries of the Fund and the Manager ("Countryside Ventures LLC") (and collectively the "Management Agreement"). Under the terms of the Management Agreement, effective November 1, 2005, Countryside Ventures commenced, providing management and administrative services to Countryside Canada and Countryside US Holding as well as new growth opportunities under long-term agreements. Effective November 1, 2005, Countryside Ventures commenced employing the Fund's current executive management team on a full time basis as well as its administrative and development staff. The Fund, through Countryside U.S. Holding and Countryside Canada, has a right of first offer on all investment opportunities developed by Countryside Ventures that meet the Fund's investment criteria. In consideration for providing the management and administrative services under the Management Agreement, the Manager shall be entitled to reimbursement from Countryside US Holding and, to the extent the Manager provides services to Countryside Canada at its request, Countryside Canada, of all costs and expenses reasonably incurred by the Manager and its affiliates in carrying out the services described above. During 2006, a total of $2,424 (2005 - $424) was expensed related to the Management Agreement. During 2006, the Management Agreement was amended as described below under "Transactions With Related Parties – Operating Agreement".

The Management Agreement is outlined in the Fund's Annual Information Form for December 31, 2005 pages 61 – 66, as filed on SEDAR at www.sedar.com. During 2006, a total of $2,931 (2005 - $805) was paid to the Manager related to the short term incentive plan and reimbursement of costs pursuant to the Management Agreement.

Shareholders' Agreement

As provided for in the Management Agreement, Countryside District Energy Corp. and Countryside Ventures are finalizing a Shareholders Agreement respecting Countryside London Cogeneration Corp. This agreement, will implement for the Countryside London Cogeneration investment, the long term incentive plan provided for in the Management Agreement ("Manager's CLCC Subordinated Interest"). Countryside Canada holds 1 preferred share in Countryside London Cogeneration Corp. (the "Preferred Share") entitling it to preferred dividends from "net cash flow" from operations and "net cash proceeds" from capital transactions as such terms will be defined in the Shareholders Agreement. Countryside Canada and Countryside Ventures hold 75 and 25 shares of common stock, respectively, in Countryside London Cogeneration Corp. (the "Common Shares") entitling them to dividends paid to common shareholders, after dividends paid to the preferred shareholders, in the ratio of their common share ownership (the "Common Dividends"). Countryside Ventures' Common Shares and Common

Dividends are subject to downward adjustment and mutual exchange as provided in the Management Agreement except that certain adjustments have been made to the timing and calculations respecting the mutual exchange to account for the fact that Countryside London Cogeneration Corp.'s asset is a development project that is not expected to achieve commercial operation until mid-2008.

Administration Agreement

On September 26, 2005 the Fund and Countryside U.S. Power entered into a Management and Administration Agreement ("Administration Agreement") with Countryside Canada Ventures Inc. ("Countryside Ventures Canada"), which is a wholly owned subsidiary of the Manager. Under the Administration Agreement, effective November 1, 2005, Countryside Ventures Canada commenced, providing management and administrative services to the Fund and Countryside Canada. In carrying out the services described above, Countryside Canada Ventures and its affiliates will be entitled to reimbursement from the Fund and Countryside Canada of all costs and expenses incurred in connection therewith. During 2006, a total of $416 (2005 – nil) was paid to Countryside Ventures Canada.

Operating Agreement

As provided for in the Management Agreement, Countryside US Holding and the Manager entered into an Operating Agreement on November 3, 2005 respecting Ripon Power which was effective as of July 1, 2005. This agreement implemented for the Ripon Power acquisition, the long-term incentive plan provided for in the Management Agreement. Under the terms of the Operating Agreement, Countryside US Holding will hold a preferred membership interest (the "Preferred Interest") entitling it to preferred distributions of "net cash flow" from operations and "net cash proceeds" from capital transactions as such terms will be defined in the Operating Agreement. Countryside US Holding and the Manager will, hold subordinate membership interests (the "Subordinate Interests") entitling them to residual distributions made to members, after distributions made in respect of the Preferred Interest, in a ratio of 75:25. The Manager's Subordinate Interest distribution is subject to downward adjustment and mutual exchange rights as provided in the Management Agreement.
During 2006 a total of $3,104, (2005 - $1,515) was distributed to Countryside Ventures and a total of $9,312 (2005 - $4,545) was distributed to the Fund pursuant to the Operating Agreement related to its Subordinated Interest.

As additional consideration for the waiver extension, the Fund was required by the syndicate of lenders to induce the Manager to waive certain existing rights and protections with respect to the Manager's 25% Subordinated Interest in Ripon Power LLC, which was originally provided as consideration to the Manager under the Management Agreement in connection with the origination and acquisition of Ripon in 2005 (the "Manager's Ripon Subordinated Interest"). The Fund holds the remaining 75% of the subordinated interest in Ripon Power LLC. In order to accommodate the lending syndicate's requirement, the board of trustees of the Fund entered into an agreement on February 9, 2007 with the Manager to purchase, on June 29, 2007 (or before in certain circumstances), 85% of the Manager's Ripon Subordinated Interest for cash and Fund units equal to $16,026 based on a unit price of $8.32. Under the prior arrangement, the Manager's Ripon Subordinated Interest could be exchanged for units of the Fund on or after June 29, 2007 (or before in certain circumstances) at the option of either the Fund or the Manager (subject to regulatory approval). The consideration to be paid will comprise a minimum of 10% cash and will provide the Fund with an option to increase the cash component up to 25% of the total consideration if the board of trustees deems such payment to be economically beneficial to the Fund. The net consideration, after settlement of 85% of the initial liability of $3,032 associated with the subordinated interest, will be charged to income in the first quarter of 2007.

In determining whether it was in the best interests of the Fund to enter into the amendment to the Management Agreement, the board of trustees of the Fund considered, among other things: (i) the importance of the waiver extension from the lending syndicate to permit the Fund to avoid enforcement actions under the Amended Credit Facility, maintain access to liquidity, pay distributions and accommodate an orderly strategic review process, (ii) the financial performance of Ripon, (iii) that the purchase price and transaction timing is substantially consistent with the consideration and transaction timing contemplated in the existing Management Agreement given that an exchange under the Management Agreement could occur no earlier than June 29, 2007, and (iv) that the amendment serves to further align the interests of Manager and the unitholders of the Fund.

After completion of the purchase of 85% of the Manager's Ripon Subordinated Interest, the Manager will hold

3.75% and the Fund will hold 96.25%, respectively, of the subordinated interest in Ripon Power LLC. The board of trustees believes that the retained Manager's Ripon Subordinated Interest will help ensure a continued focus by the Manager on potential Ripon-related growth opportunities. The Fund and Manager have also agreed that neither party will exercise its option to exchange the remaining 15% of the Manager's Subordinated Interest until February 9, 2009 (or earlier in certain circumstances). As part of its decision to enter into this agreement, the board of trustees sought and received an opinion as to the fairness of the consideration to be paid in connection with the amendment to the Management Agreement.

Indemnification Agreement

On December 21, 2006, The Fund and Countryside Canada agreed to indemnify the principals of Countryside Ventures respecting certain claims arising out disputes with USEY, USEB and the USEB bankruptcy.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

The Fund's Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining the Fund's disclosure controls and procedures and internal control over financial reporting (as defined in the Canadian Securities Administrators' Multilateral Instrument 52-109).

The Chief Executive Officer and the Chief Financial Officer, after evaluating the effectiveness of the Fund's disclosure controls and procedures as at December 31, 2006, have concluded that the Fund's disclosure controls and procedures are adequate and effective to ensure that material information relating to the Fund and its consolidated subsidiaries would have been known to them.

Internal control over financial reporting ("ICFR") is designed to provide reasonable assurance regarding the reliability of the Fund's financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The Chief Executive Officer and the Chief Financial Officer have evaluated whether there were any material changes in the Fund's ICFR that were made during the quarter ended December 31, 2006. No such changes were identified through their evaluation.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Fund's consolidated financial statements requires the Fund to make estimates and judgments as they relate to matters that are inherently uncertain. Changes in these judgments or estimates could have a significant impact on the Fund's consolidated financial statements. The Fund believes that the following critical accounting estimates involve the more significant estimates and judgments used in the preparation of our annual consolidated financial statements.

Power Purchase Agreements

Power purchase agreements ("PPAs") were recorded at their fair values at the time of the purchase of Ripon Power. The fair value of the intangible asset balance is being amortized over the life of the PPAs expiring in 2016 & 2018.

Customer Relationships

Customer relationships were recorded at their fair values at the time of the acquisition of the District Energy Systems. The fair value of the customer relationships balance is being amortized over 21 years on a straight-line basis. The Fund has used judgment and estimates in determining the appropriate amortization period giving consideration to both the historical performance of customer renewals and the useful life of the energy service agreements in place at the time of the acquisition of the District Energy Systems by the Fund.

USEB Loan Receivable

The Fund has both credit and market risk with respect to the future monetization of the USEB Allowed Secured Claim under the USEB Settlement Agreement as described above under "Overview of Fund and Recent Developments – Recent Developments – USEB Settlement Subsequent to USEB's Voluntary Filing for

Reorganization Under Chapter 11 of the U.S. Bankruptcy Code", including the exit financing required for USEB to repay the balance of the Allowed Secured Claim outstanding on May 31, 2007.

OUTLOOK

As part of the strategic review process, the Fund is developing plans to remain a "stand alone" entity while it seeks to determine the Fund's value through a potential sale of the trust to interested buyers. To date, the board of trustees is encouraged by the results of the sale process and will continue to weigh those plans against a stand alone strategy with a view to maximizing unitholder value. A stand alone strategy may comprise several options, including a continuation of operations under the existing trust structure and the Fund's use of proceeds from the expected monetization of the USEB allowed secured claim to (i) fund (with the incurrence of additional leverage) the re-powering of the Cogen Facilities and the new 17 megawatt London cogeneration facility and/or (ii) a recapitalization which may involve a re-leveraging of the Fund with a return of capital to unitholders through a special distribution or unit buy back. Under a potential stand alone plan, any new growth-related investment or recapitalization strategy would be designed to provide accretive distributable cash flow to unitholders. However, the Fund currently does not intend to reinvest the proceeds from any future monetization of the USEB allowed secured claim until the strategic review process has been completed. The board of trustees of the Fund expects the strategic review process to be completed by the end of June 2007

During the course of 2007, the Fund will reassess the level of its unitholder distributions as part of its the strategic review process currently underway, and will take into consideration important factors such as the; (i) a possible sale of the Fund or remaining independent (ii) the impact of the expected monetization of the USEB Allowed Secured Claim and concomitant use of proceeds, (iii) the SRAC proceeding before the California Public Utility Commission as it relates to energy payments received under the power purchase agreements and (iv) successful placement of a new or amended credit facility or other financing to support liquidity and ongoing growth initiatives.

Operations

The ongoing operations of the District Energy Systems, combined with both the completion of the 17 MW cogeneration facility at the London system in mid-2008, and the addition of peak boiler capacity in PEI in 2007, is expected to result in expanded operations and provide opportunities for additional customer growth beyond customers already contracted for connection in the next few years.

Major maintenance is planned for the Cogen Facilities for the 2008-2009 periods. However, the Fund has developed advanced plans for the re-powering of the facilities with more efficient combustion turbines, which would replace the existing turbines and eliminate the need for major overhaul in the next several years. The re-powering of the Cogen Facilities would also provide for improved efficiency and additional energy production at the facilities. Subject to, among other things, normal course permitting and finalizing documentation relating to additional off-take arrangements as well as construction contracts, the re-powering of the Cogen Facilities would be expected to reach commercial operation by the end of 2008.

COUNTRYSIDE
POWER INCOME FUND

Countryside Power Income Fund Reports Financial Results for Fiscal Year 2006

Strategic Alternatives Review Process Continues

(London, Ontario, March 27, 2007) -- Countryside Power Income Fund (TSX: COU.UN) ("the Fund") today announced its financial results for the fourth quarter and year ended December 31, 2006. All figures are in Canadian dollars unless otherwise stated.

Highlights for Fiscal 2006:

- The Fund made all declared monthly distributions to unitholders and ended year with payout ratio of 87% of total distributable cash flow

- Adjusted EBITDA for 2006, was \$30.3 million, an increase of \$9.0 million or 42% from the prior year period, due primarily to the economic optimization of the California cogeneration facilities ("Cogen Facilities") and the inclusion of their full year results in 2006

- Organic growth strategy was advanced with the awarding of a 20-year combined heat and power generation contract by the Ontario Power Authority for a new cogeneration facility at the site of the Fund's district energy system in London, Ontario

- On October 31, 2006, the Canadian Federal government announced tax proposals pertaining to the taxation of distributions paid by income trusts and changes to the personal tax treatment of distributions that would commence in the calendar year 2011

- Following the U.S. Energy Biogas Corp.'s ("USEB") Chapter 11 filing, the Fund entered into a settlement agreement with USEB in January 2007 that resolved all outstanding claims between the parties, including the USEB loan, which provided the Fund with an allowed secured claim of US\$99 million (approximately \$115 million at Cdn/US dollar exchange rate of 1.17)

- The U.S. Bankruptcy Court approved the USEB settlement in principle on February 1, 2007 and it became final and non-appealable on February, 26 2007. To date, the Fund has received approximately US\$34 million from USEB in the form of both principal and interest payments pursuant to the court-approved settlement agreement

- The Fund's board of trustees has initiated a strategic review process in response to both the expected full monetization of the Fund's allowed secured claim in USEB and the federal government's proposed legislation to tax income trusts with a view to maximizing unitholder value

"We had a strong year of operating results that was overshadowed in the final months by two significant events – the Canadian government's trust tax proposal and USEB's filing for reorganization," said Göran Mörnhed, President and Chief Executive Officer of Countryside Ventures LLC (the "Manager"). "The substantial increase in distributable cash flow was driven primarily by the performance of the cogen facilities and validates our successful economic optimization plan for these assets. In light of the successful settlement agreement with USEB and potential tax impact on the income trust market, we must now decide on a strategic path for the Fund that will serve the best interests of unitholders" said Mr. Mörnhed.

Results for Fiscal 2006

The Fund's total revenue in the twelve months ended December 31, 2006, was $92.5 million, an increase of $25.3 million compared with the same period last year. The majority of this increase resulted from inclusion of the Cogen Facilities' results for the full fiscal year 2006.

Adjusted EBITDA for 2006, was $30.3 million, an increase of $9.0 million from the prior year period, due primarily to the addition and economic optimization of the Cogen Facilities. When excluding the non-cash general and administrative expense of the Manager's Ripon-related subordinated interest in the third quarter of 2005, the Adjusted EBITDA, reflecting solely the operating performance of the Fund's energy portfolio, increased by 24% or $5.8 million. The increase in margins at the Cogen Facilities was offset by lower margins at the district energy systems due to warmer weather during the primary heating season and higher planned maintenance costs, as well as higher associated general and administrative expenses.

Net income for 2006 was $12.8 million, or $0.64 per unit, compared with $11.2 million or $0.72 per unit in the comparable period of 2005. When excluding the non-cash general and administrative expense of the Manager's Ripon-related subordinated interest in the third quarter of 2005, net income decreased by $0.21 per trust unit as a result of an increase in interest expense and non-cash losses on derivative instruments and foreign exchange, offset by an increase in the tax recovery.

In the twelve-month period ended December 31, 2006, distributable cash of $24.0 million increased by 20% or $4.0 million from the prior year period. On a weighted-average per-unit basis, distributable cash of $1.20 per trust unit decreased 7% per trust unit from the prior year comparative period. The decrease in per unit distributable cash flow was due to the greater number of weighted average units outstanding at the end of the 2006 primarily resulting from the issuance of new trust units in November 2005 to refinance bank debt related to the Ripon acquisition and to de-lever the Fund's balance sheet in accordance with terms of the Fund's credit agreement with a syndicate of lenders. Distributions to Unitholders declared for 2006 totaled $1.035 per unit. The Fund's payout ratio was 87% for the twelve-month period ended December 31, 2006.

Comparisons of the Fund's overall results in the twelve-month period ended December 31 are significantly influenced by the acquisition of the Cogen Facilities at the end of the second quarter of 2005 in that the results of the Cogen Facilities were not included in the Fund's results for the first six months of 2005.

Consolidated Statements of Income and Deficit

[in thousands of Canadian dollars, except per trust unit amounts]	Three Months ended Dec. 31, 2006	Three Months ended Dec. 31, 2005	Year ended Dec. 31, 2006	Year ended Dec. 31, 2005 (as restated)
	$	$	$	$
REVENUES				
Energy sales	19,042	20,274	78,071	52,823
Fuel and other fees	432	422	1,991	2,252
Interest income on loans to U.S. Energy Biogas Corp.	2,995	2,868	11,517	11,546
Income from U.S. Energy Biogas Corp. royalty interest	-	133	350	369
Other income	202	145	528	171
	22,672	23,842	92,457	67,161
EXPENSES				
Fuel, operating and maintenance	15,136	14,391	53,017	34,898
General and administration	2,398	2,965	9,150	10,949
Amortization	3,013	3,097	11,948	8,061
	20,547	20,453	74,115	53,908
Operating income	**2,124**	**3,389**	**18,342**	**13,253**
Interest expense	1,657	2,237	7,104	5,578
Loss (gain) on derivative instruments	287	(784)	148	(2,871)
Foreign exchange gain	2,474	(750)	(373)	(750)
	4,418	703	6,879	1,957
Income before (recovery of) provision for income taxes	**(2,294)**	**2,686**	**11,463**	**11,296**
(Recovery of) provision for income taxes				
Current	(1,267)	(1,077)	438	22
Future	(2,651)	(276)	(1,779)	30
	(3,918)	(1,353)	(1,341)	52
Net income for the period	**1,624**	**4,039**	**12,804**	**11,244**
Deficit, beginning of year as previously reported	(10,756)	(7,862)	(6,580)	(3,596)
Correction of prior year	(1,917)	-	(1,917)	-
Deficit, as restated	(12,673)	-	(8,497)	-
Distributions declared to Unitholders	(5,382)	(4,674)	(20,738)	(16,145)
Deficit, end of year	**(16,431)**	**(8,497)**	**(16,431)**	**(8,497)**
Net income per trust unit – basic	**0.08**	**0.23**	**0.64**	**0.72**
Net income per trust unit – diluted	**0.09**	**0.22**	**0.64**	**0.72**

[1] The subordinated interest expense for 2005 includes a non-cash expense of $3,196 reflecting the estimated value of the Manager's subordinated interest at such time.

Results for Fourth Quarter 2006

The Fund's total revenue for the three months ended December 31, 2006, was $22.7 million, a decrease of $1.2 million compared with the same period last year.

Adjusted EBITDA in the three-months ended December 31, 2006, was $5.1 million, a decrease of 11% from the prior year period, due primarily to the unfavorable foreign exchange impact on results from the Cogen Facilities, coupled with reduced margins from lower natural gas and associated electric energy pricing, as well as higher non-fuel costs primarily driven by a hot section overhaul at the Ripon facility. The lower results were also due to lower margins from the district energy business due to moderate weather during the primary heating season along with higher operating costs.

Net income in the three-month period ended December 31, 2006, was $1.6 million or $0.08 per unit, compared with $4.0 million or $0.23 per unit in the comparable period of 2005.

In the three-month period ended December 31, 2006, the Fund generated distributable cash of $5.0 million which was lower than the prior year comparative period by $1.2 million. The decrease in distributable cash was primarily a result of the factors related to the decrease in Adjusted EBITDA, coupled with a reduction in the receipt of principal on the USEB Loans. On a per-unit basis, distributable cash of $0.241 per trust unit decreased $0.12 per trust unit from the prior year comparative period. Distributions to unitholders declared for the quarter were $0.259 per unit. The Fund's payout ratio was 108% in the three-month period ended December 31, 2006 due to the seasonality of its cash flows and non-payment of scheduled principal payments from USEB.

Accounting for Manager's Subordinated Interest

In March 2007, the board of trustees reviewed the initial accounting for the granting of the Manager's subordinated interest in Ripon Power LLC and determined that compensation expense consisting of the fair value of the subordinate interest at the time of the grant was required to be recorded in the third quarter of 2005. Accordingly, in the fiscal year ended 2005, general and administrative expenses have been increased by $3.2 million, offset by a decrease in the provision for future income taxes and net income of $1.3 million and $1.9 million, respectively. As a result of the Manager's option to exchange its subordinated interest for a variable number of units of the Fund, the subordinated interest has been classified as a long-term liability totaling approximately $3 million in the Fund's consolidated balance sheet in 2005. However, the associated cash flow and value of the subordinated interest was not reflected in the purchase price paid by the Fund for the Ripon cogeneration assets.

In the twelve-month period ended 2006, the liability associated with the Manager's subordinated interest in the amount of $3 million has now been included in current liabilities in light of the Fund's agreement to purchase 85% of the Manager's subordinated interest in June 2007. The resulting prior period adjustment did not have any impact on distributable cash flow in fiscal 2005 as the associated expense was a non-cash item.

Distributable Cash Summary

The Fund pays monthly cash distributions to unitholders on or about the last business day of each month to unitholders of record on the last business day of the prior month.

	Three-month period ended December 31, 2006	Three-month period ended December 31, 2005	Year ended December 31, 2006	Year ended December 31, 2005 (as restated)
	$	$	$	$
Cash provided by operating activities	**3,903**	**3,145**	**20,430**	**16,772**
Add: Changes in working capital	876	2,205	2,159	2,162
Funds from operations before working capital changes	4,779	5,350	22,589	18,934
Add:				
Receipt of principal on USEB loans	175	476	1,684	1,828
Transaction costs expensed[1]	357	642	357	1,080
Deduct:				
Principal repayments on Cogen Facilities' project-related debt	-	-	-	957
Purchases of capital assets for regular operations[2]	310	128	670	504
Royalty Interest[3]	-	133	-	369
Distributable cash for the period	**5,001**	**6,207**	**23,960**	**20,012**
Distributions declared for the period	**5,382**	**4,674**	**20,738**	**16,145**
Weighted Average number of trust units outstanding				
– basic (thousands of trust units)	**20,730,576**	**17,316,670**	**19,968,697**	**15,513,147**
– diluted (thousands of trust units)	**26,461,700**	**23,338,532**	**25,647,228**	**21,535,009**
Distributable cash per trust unit for the period - basic	**0.241**	**0.358**	**1.200**	**1.290**
Distributions declared per trust unit for the period (whole dollars)	**0.259**	**0.271**	**1.035**	**1.041**

[1] During 2005, transaction costs related to the Ripon acquisition transaction and during 2006, related to the London Cogen project acquisition were paid to the Manager and advisors out of financing proceeds and were not operational in nature

[2] Purchases of capital assets for regular operations are non-expansionary capital expenditures. Total capital expenditures were as follows: in the three-month period ended December 31, 2006 - $1,613, for the three-month period ended December 31, 2005 - $65, in the twelve-month period ended December 31, 2006 - $3,399 and in the twelve-month period ended December 31, 2005 - $855.

[3] As the timing of the receipt of the royalty interest income earned in a period is dependent upon the timing and extent of equity distributions made by USEB to its shareholders', royalty interest income will only be included in the calculation of distributable cash when payments related to the royalty interest are received from USEB.

Outlook

USEB Settlement Agreement: Pursuant to the USEB settlement agreement the Fund has received approximately US$33 million in payments against the allowed secured claim and in turn has made a $35 million mandatory prepayment in accordance with the terms of its credit facility provided by a syndicate of lenders. The Fund currently has a remaining balance of approximately US$66 million (or $78 million) that matures on May 31, 2007. USEB is pursuing an exit financing from a third party lender which is expected to fully repay the Fund's remaining allowed secured claim. The Fund is exposed to both credit and market risk with respect to USEB and the successful efforts to complete an exit financing, respectively. On March 22, 2007, USEB announced that it has reached an agreement in principle with the State of Illinois and the Illinois Commerce Commission (collectively, the "ICC") on eliminating a significant balance sheet liability for USEB and resolving the principal remaining outstanding issue in its Chapter 11 filing. The ICC agreement is subject to court approval which the ICC and USEB expect to occur next month. As a result of the USEB agreement with the ICC along with its court-approved settlement agreement with the Fund, USEB indicated that it expects to file shortly a plan of reorganization with the Court that should enable it to exit Chapter 11 in the first half of 2007.

Fund Credit Facility: The USEB bankruptcy filing and its related payment default caused a cross default under the Fund's credit facility. The lenders under the credit facility granted two waivers of the cross-default including most recently a waiver granted on January 25, 2007, which among other things (i) waived the cross-default provisions under the USEB loan agreement until May 31, 2007, (ii) reinstated the credit facility's credit commitment (subject to compliance with financial covenants), (iii) permitted unitholder distributions and permitted investments and capital expenditures (including the London cogeneration facility), (iv) approved the USEB settlement agreement, (v) required the Fund to provide additional collateral relating to Ripon-related assets and (vi) for the Manager to waive certain rights associated with its subordinated interest in Ripon.

Following the Fund's receipt of the US$30 million installment under the USEB settlement agreement and subsequent mandatory prepayment of $35 million on March 14, 2007 in accordance with terms of its bank credit facility, the revolver commitment portion of the credit facility was permanently reduced to approximately $43 million. However, the Fund continues to have ample liquidity with approximately $30 million of unutilized credit capacity and $8 million of cash on hand to fund the construction of London cogeneration facility and meet ongoing liquidity needs. As part of the strategic review process, the Fund is in discussion with it lenders on a long-term financing arrangement that reflects the expected full monetization of the USEB allowed secured claim under the settlement agreement and provides the Fund with sufficient credit capacity to meet its existing growth commitments.

Operations and Growth: The ongoing operations of the District Energy Systems, combined with both the completion of the 17 MW cogeneration facility at the London system in mid-2008, and the addition of peak boiler capacity in PEI in 2007, is expected to result in expanded operations and provide opportunities for additional customer growth beyond customers already contracted for connection in the next few years.

Major maintenance is planned for the Cogen Facilities for the 2008-2009 periods. However, the Fund has developed advanced plans for the re-powering of the facilities with more efficient combustion turbines, which would replace the existing turbines and eliminate the need for major overhaul in the next several years. The re-powering of the Cogen Facilities would also provide for improved efficiency and additional energy production at the facilities. Subject to, among other things, normal course permitting and finalizing documentation relating to additional off-take arrangements as well as construction contracts, the re-powering of the Cogen Facilities would be expected to reach commercial operation by the end of 2008.

Strategic Review Update: As previously disclosed, the Fund has retained Lehman Brothers, Inc. to assist and advise the Fund in identifying and considering the Fund's strategic alternatives with a view toward the best interests of unitholders. The Fund has also considered a range of value enhancement alternatives, including a review of the Fund's prospects going forward as an income trust, a sale of the Fund (or its segments), a conversion to a corporate structure and/or a recapitalization. As part of the strategic review process, the Fund is developing plans to remain a "stand alone" entity while it seeks to determine the Fund's value through a potential sale of the trust to interested buyers. To date, the board of trustees is encouraged by the results of the sale process and will continue to weigh those plans against a stand alone strategy with a view to maximizing unitholder value. A stand alone strategy may comprise several options, including a continuation of operations under the existing trust structure and the Fund's use of proceeds from the expected monetization of the USEB allowed secured claim to (i) fund (with the incurrence of additional leverage) the re-powering of the Cogen Facilities and the new 17 megawatt London cogeneration facility and/or (ii) a recapitalization which may involve a re-leveraging of the Fund with a return of capital to unitholders through a special distribution or unit buy back. Under a potential stand alone plan, any new growth-related investment or recapitalization strategy would be designed to provide accretive distributable cash flow to unitholders. However, the Fund currently does not intend to reinvest the proceeds from any future monetization of the USEB allowed secured claim until the strategic review process has been completed. The board of trustees of the Fund expects the strategic review process to be completed by the end of June 2007.

Conference Call and Webcast

Management will host a conference call at 10 a.m. (ET) on Tuesday, March 27, 2007, to discuss the results. Please call **416-644-3417** or **1-800-733-7560** to access the call. The call will be webcast live and archived on the Countryside web site at www.countrysidepowerfund.com.

Countryside's financial statements for the period and management's discussion and analysis are available at www.countrysidepowerfund.com.

* Non-GAAP Measures

Distributable cash does not have any standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other issuers. Since the Fund and its subsidiaries distribute substantially all of their available cash on an on-going basis, management believes that distributable cash is an important measure in evaluating the performance of the Fund and determining whether to invest in units of the Fund. For a reconciliation of cash provided by operating activities from the Consolidated Statements of Cash Flows to distributable cash please see the Fund's MD&A for the period ended December 31, 2006.

Adjusted earnings before interest, income taxes, unrealized (gains) losses on derivative instruments, foreign exchange gains and losses, and depreciation and amortization ("Adjusted EBITDA") is not a measure under Canadian GAAP and there is no standardized measure of Adjusted EBITDA and therefore, it may not be comparable to similar measures presented by other funds or companies. Management uses Adjusted EBITDA as a key measure of operating performance, and thus has framed a portion of the MD&A comments accordingly. Adjusted EBITDA can be calculated from the Fund's GAAP statements as operating income, plus depreciation and amortization.

Forward-Looking Statements

This press release may contain forward-looking statements relating to expected future events and financial and operating results of the Fund that involve risks and uncertainties. Actual results may differ materially from management expectations as projected in such forward-looking statements for a variety of reasons, including market and general economic conditions and the risks and uncertainties detailed from time to time in the Fund's prospectus filed with the Canadian securities regulatory authorities. Due to the potential impact of these factors, the Fund disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable law.

About Countryside Power Income Fund

Countryside Power Income Fund has investments in two district energy systems in Canada, with a combined thermal and electric generation capacity of approximately 122 megawatts, and two gas-fired cogeneration plants in California with a combined power generation capacity of 94 megawatts. More information about the Fund is available at www.countrysidepowerfund.com

Further information:

BarnesMcInerney Inc.	Edward M. Campana	Nicole Archibald
Andrew Kondraski	Executive Vice President & CFO	Vice President Finance & Administration
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Certification of Annual Filings

Form 52-109F1

I, Edward M. Campana, Executive Vice President and Chief Financial Officer of Countryside Ventures LLC, the manager of certain subsidiaries of Countryside Power Income Fund, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of **Countryside Power Income Fund** (the issuer) for the period ending December 31, 2006;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

   a. designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared.

   b. designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

   c. evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

"Edward M. Campana"

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Edward M. Campana
Executive Vice President and Chief Financial Officer
Countryside Ventures LLC

March 30, 2007

Certification of Annual Filings

Form 52-109F1

I, Göran Mörnhed, President and Chief Executive Officer of Countryside Ventures LLC, the manager of certain subsidiaries of Countryside Power Income Fund, certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of **Countryside Power Income Fund** (the issuer) for the period ending December 31, 2006;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

   a. designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared.

   b. designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

   c. evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

"Goran Mornhed"

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Göran Mörnhed
President and Chief Executive Officer
Countryside Ventures LLC

March 30, 2007

END