HGT

2010 ANNUAL REPORT

GLOSSARY OF TERMS

The following are definitions of significant terms used in this Annual Report.

Bbl Barrel (of oil)

Bcf Billion cubic feet (of natural gas)

Mcf Thousand cubic feet (of natural gas)

MMBtu One million British Thermal Units, a common energy measurement

Net Proceeds Gross proceeds received by XTO Energy from sale of production from the underlying properties, less applicable costs, as defined in the net profits interest conveyances

Net Profits Income Net proceeds multiplied by the net profits percentage of 80%, which is paid to the trust by XTO Energy. "Net profits income" is referred to as "royalty income" for tax reporting purposes.

Net Profits Interest An interest in an oil and gas property measured by net profits from the sale of production, rather than a specific portion of production. The following defined net profits interests were conveyed to the trust from the underlying properties:

80% net profits interests – interests that entitle the trust to receive 80% of the net proceeds from the underlying properties.

Underlying Properties XTO Energy's interest in certain oil and gas properties from which the net profits interests were conveyed. The underlying properties include working interests in predominantly gas-producing properties located in Kansas, Oklahoma and Wyoming.

Working Interest An operating interest in an oil and gas property that provides the owner a specified share of production that is subject to all production expense and development costs

THE TRUST

Hugoton Royalty Trust was created on December 1, 1998 when XTO Energy Inc. conveyed 80% net profits interests in certain predominantly gas-producing properties located in Kansas, Oklahoma and Wyoming to the trust. The net profits interests are the only assets of the trust, other than cash held for trust expenses and for distribution to unitholders.

Net profits income received by the trust on the last business day of each month is calculated and paid by XTO Energy based on net proceeds received from the underlying properties in the prior month. Distributions, as calculated by the trustee, are paid to month-end unitholders of record within ten business days.

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation. The merger is not expected to have a material effect on trust annual distributable income, financial position or liquidity.

SUMMARY

The trust was created to collect and distribute to unitholders monthly net profits income related to the 80% net profits interests. Such net profits income is calculated as 80% of the net proceeds received from certain working interests in predominantly gas-producing properties in Kansas, Oklahoma and Wyoming. Net proceeds from properties in each state are calculated by deducting production expense, development costs and overhead from revenues. If monthly costs exceed revenues from the underlying properties in any state, such excess costs must be recovered, with accrued interest, from future net proceeds of that state and cannot reduce net profits income from another state. Excess costs generally can occur during periods of higher development activity and/or lower gas prices.

Costs exceeded revenues on properties underlying the Wyoming net profits interests in November 2008 and November and December 2007 and on properties underlying the Kansas net profits interests in October and November 2009. There were no excess costs at December 31, 2010. For further information on excess costs, see "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" under Item 7 of the accompanying Form 10-K.

Cost Depletion is generally available to unitholders as a deduction from royalty income. Available depletion is dependent upon the unitholder's cost of units, purchase date and prior allowable depletion. It may be more beneficial for unitholders to deduct percentage depletion. Unitholders should consult their tax advisors for further information.

As an example, a unitholder that acquired units in January 2010 and held them throughout 2010 would be entitled to a cost depletion deduction of approximately 10% of his cost. Assuming a cost of $17.00 per unit, cost depletion would offset approximately 115% of 2010 taxable trust income. Assuming a 30% tax rate, the 2010 taxable equivalent return as a percentage of unit cost would be 14%. (NOTE – Because the units are a depleting asset, a portion of this return is effectively a return of capital.)

TO UNITHOLDERS

We are pleased to present the 2010 Annual Report on Form 10-K of the Hugoton Royalty Trust as filed with the Securities and Exchange Commission. This report contains important information about the trust's net profits interests, including information provided to the trustee by XTO Energy. On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation. The merger is not expected to have a material effect on trust annual distributable income, financial position or liquidity.

For the year ended December 31, 2010, net profits income totaled $62,883,206. After adding interest income of $1,108 and deducting trust administration expense of $856,314, distributable income was $62,028,000 or $1.550700 per unit. Net profits income and distributions were 108% and 112%, respectively, higher than 2009 amounts primarily because of higher oil and gas prices and decreased development costs, partially offset by decreased gas production.

Natural gas prices averaged $4.72 per Mcf for 2010, 40% higher than the 2009 average price of $3.38 per Mcf. The average 2010 oil price was $73.77 per Bbl, 36% higher than the 2009 average price of $54.10 per Bbl.

Gas sales volumes from the underlying properties for 2010 were 24,074,923 Mcf, or 65,959 Mcf per day, a decrease of 10% from 72,991 Mcf per day in 2009. Oil sales volumes from the underlying properties were 266,656 Bbls, or 731 Bbls per day in 2010, an increase of 2% from 714 Bbls per day in 2009. For further information on sales volumes and product prices, see "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" under Item 7 of the accompanying Form 10-K.

As of December 31, 2010, proved reserves for the underlying properties were estimated by independent engineers to be 315.0 Bcf of natural gas and 2.9 million Bbls of oil. Natural gas reserves for the underlying properties declined 8.3 Bcf and oil reserves for the underlying properties declined approximately 0.1 million Bbls primarily due to current year production, partially offset by revisions from higher oil and gas prices. Based on an allocation of these reserves, proved reserves attributable to the net profits interests were estimated to be 138.4 Bcf of natural gas and 1.3 million Bbls of oil. Estimated gas and oil reserves attributable to the net profits interests increased from previously reported reserves at year-end 2009 as revisions due to higher oil and gas prices were partially offset by current year production. All reserve information prepared by independent engineers has been provided to the trustee by XTO Energy.

Estimated future net cash flows from proved reserves of the net profits interests at December 31, 2010 are $664 million. Using an annual discount factor of 10%, the present value of estimated future net cash flows at December 31, 2010 is $340 million. Proved reserve estimates and related future net cash flows have been determined based on a 12-month average gas price of $4.45 per Mcf and a 12-month average oil price of $75.91 per Bbl, based on the first-day-of-the-month price for each month in the period, and year end costs. Other guidelines used in estimating proved reserves, as prescribed by the Financial Accounting Standards Board, are described in Note 9 to Financial Statements under Item 8, "Financial Statements and Supplementary Data" of the accompanying Form 10-K. The present value of estimated future net cash flows is computed based on SEC guidelines and is not necessarily representative of the market value of trust units.

As disclosed in the tax instructions provided to unitholders in February 2011, trust distributions are considered portfolio income, rather than passive income. Unitholders should consult their tax advisors for further information.

HUGOTON ROYALTY TRUST

By: U.S. Trust, Bank of America
Private Wealth Management, Trustee

By: Nancy G. Willis
Vice President

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

FORM 10-K

**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010
Commission file number 1-10476

Hugoton Royalty Trust

(Exact name of registrant as specified in the Hugoton Royalty Trust Indenture)

Texas (State or other jurisdiction of incorporation or organization)	**58-6379215** (I.R.S. Employer Identification No.)
U.S. Trust, Bank of America Private Wealth Management Trustee P.O. Box 830650 Dallas, Texas (Address of principal executive offices)	**75283-0650** (Zip Code)

Registrant's telephone number including area code: (877) 228-5083

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

Title of each class	Name of each exchange on which registered
Units of Beneficial Interest	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (check one):

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☒

The aggregate market value of the units of beneficial interest of the trust, based on the closing price on the New York Stock Exchange as of June 30, 2010 (the last business day of its most recently completed second fiscal quarter), held by non-affiliates of the registrant on that date was approximately $753 million.

At February 16, 2011, there were 40,000,000 units of beneficial interest of the trust outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Listed below is the only document parts of which are incorporated herein by reference and the parts of this report into which the document is incorporated:

None

HUGOTON ROYALTY TRUST
2010 ANNUAL REPORT ON FORM 10-K

TABLE OF CONTENTS

[This page intentionally left blank.]

HUGOTON ROYALTY TRUST

GLOSSARY OF TERMS

The following are definitions of significant terms used in this Annual Report on Form 10-K:

Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Mcf	Thousand cubic feet (of natural gas)
MMBtu	One million British Thermal Units, a common energy measurement
net proceeds	Gross proceeds received by XTO Energy from sale of production from the underlying properties, less applicable costs, as defined in the net profits interest conveyances.
net profits income	Net proceeds multiplied by the net profits percentage of 80%, which is paid to the trust by XTO Energy. "Net profits income" is referred to as "royalty income" for tax reporting purposes.
net profits interest	An interest in an oil and gas property measured by net profits from the sale of production, rather than a specific portion of production. The following defined net profits interests were conveyed to the trust from the underlying properties: *80% net profits interests* — interests that entitle the trust to receive 80% of the net proceeds from the underlying properties.
underlying properties	XTO Energy's interest in certain oil and gas properties from which the net profits interests were conveyed. The underlying properties include working interests in predominantly gas-producing properties located in Kansas, Oklahoma and Wyoming.
working interest	An operating interest in an oil and gas property that provides the owner a specified share of production that is subject to all production expense and development costs.

PART I

Item 1. *Business*

Hugoton Royalty Trust is an express trust created under the laws of Texas pursuant to the Hugoton Royalty Trust Indenture entered into on December 1, 1998 between XTO Energy Inc. (formerly known as Cross Timbers Oil Company), as grantor, and NationsBank, N.A., as trustee. Bank of America, N.A., successor to NationsBank, N.A., is now the trustee of the trust. In 2007 the Bank of America private wealth management group officially became known as ‘‘U.S. Trust, Bank of America Private Wealth Management.’’ The legal entity that serves as the trustee of the trust did not change, and references in this Form 10-K to U.S. Trust, Bank of America Private Wealth Management shall describe the legal entity Bank of America, N.A. The principal office of the trust is located at 901 Main Street, Dallas, Texas 75202 (telephone number 877-228-5083).

The trust's internet web site is www.hugotontrust.com. We make available free of charge, through our web site, our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934. These reports are accessible through our internet web site as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

Effective December 1, 1998, XTO Energy conveyed to the trust 80% net profits interests in certain predominantly natural gas producing working interest properties in Kansas, Oklahoma and Wyoming under three separate conveyances. In exchange for these net profits interest conveyances to the trust, 40 million units of beneficial interest were issued to XTO Energy. In April and May 1999, XTO Energy sold a total of 17 million units in the trust's initial public offering. In 1999 and 2000, XTO Energy also sold 1.3 million trust units to certain of its officers. The trust did not receive the proceeds from these sales of trust units. Units are listed and traded on the New York Stock Exchange under the symbol ‘‘HGT.’’ In May 2006, XTO Energy distributed all of its remaining 21.7 million trust units as a dividend to its common stockholders. XTO Energy currently is not a unitholder of the trust.

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation. The merger is not expected to have a material effect on trust annual distributable income, financial position or liquidity.

The net profits interests entitle the trust to receive 80% of the net proceeds from the sale of oil and gas from the underlying properties. Each month XTO Energy determines the amount of cash received from the sale of production and deducts property and production taxes, production expense, development costs and overhead.

Net proceeds payable to the trust depend upon production quantities, sales prices of oil and gas and costs to develop and produce oil and gas in the prior month. If monthly costs exceed revenues for any of the three conveyances (one for each of the states of Kansas, Oklahoma and Wyoming), such excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net proceeds from other conveyances.

Costs exceeded revenues on properties underlying the Wyoming net profits interests for November 2008 and November and December 2007 and on properties underlying the Kansas net profits interests for October and November 2009. There were no excess costs at December 31, 2010. For further information on excess costs, see Trustee's Discussion and Analysis of Financial Condition and Results of Operations, under Item 7.

The trust is not liable for any production costs or liabilities attributable to the underlying properties. If at any time the trust receives net profits income in excess of the amount due, the trust is not obligated to return such overpayment, but net profits income payable to the trust for the next month will be reduced by the overpayment, plus interest at the prime rate.

As a working interest owner, XTO Energy can generally decline participation in any operation and allow consenting parties to conduct such operations, as provided under the operating agreements. XTO Energy also can assign, sell, or otherwise transfer its interest in the underlying properties, subject to the net profits interests, or can abandon an underlying property if it is incapable of producing in paying quantities, as determined by XTO Energy.

To the extent allowed, XTO Energy is responsible for marketing its production from the underlying properties under existing sales contracts or new arrangements on the best terms reasonably obtainable in the circumstances. See ''Pricing and Sales Information'' under Item 2, Properties.

Net profits income received by the trust on or before the last business day of the month is related to net proceeds received by XTO Energy in the preceding month, and is generally attributable to oil and gas production two months prior. The amount to be distributed to unitholders each month by the trustee is determined by:

Adding –

(1) net profits income received,

(2) interest income and any other cash receipts and

(3) cash available as a result of reduction of cash reserves, then

Subtracting –

(1) liabilities paid and

(2) the reduction in cash available related to establishment of or increase in any cash reserve.

The monthly distribution amount is distributed to unitholders of record within ten business days after the monthly record date. The monthly record date is generally the last business day of the month. The trustee calculates the monthly distribution amount and announces the distribution per unit at least ten days prior to the monthly record date.

The trustee may establish cash reserves for contingencies. Cash held for such reserves, as well as for pending payment of the monthly distribution amount, may be invested in federal obligations or certificates of deposit of major banks.

The trustee's function is to collect the net profits income from the net profits interests, to pay all trust expenses, and pay the monthly distribution amount to unitholders. The trustee's powers are specified by the terms of the trust indenture. The trust cannot engage in any business activity or acquire any assets other than the net profits interests and specific short-term cash investments. The trust has no employees since all administrative functions are performed by the trustee.

Approximately 85% of the net profits income received by the trust during 2010, as well as 87% of the estimated proved reserves of the net profits interests at December 31, 2010 (based on estimated future net cash flows using 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period), is attributable to natural gas. There has historically been a greater demand for gas during the winter months than the rest of the year. Otherwise, trust income generally is not subject to seasonal factors, nor dependent upon patents, licenses, franchises or concessions. The trust conducts no research activities.

The oil and gas industry is highly competitive in all its phases. Operators of the properties in which the trust holds interests encounter competition from other oil and gas companies and from individual producers and operators. Oil and natural gas are commodities, for which market prices are determined by external supply and demand factors.

Item 1A. ***Risk Factors***

The following factors could cause actual results to differ materially from those contained in forward-looking statements made in this report and presented elsewhere by the trustee from time to time. Such factors may have a material adverse effect upon the trust's financial condition, distributable income and changes in trust corpus.

The following discussion of risk factors should be read in conjunction with the financial statements and related notes included under Item 8, Financial Statements and Supplementary Data. Because of these and other factors, past financial performance should not be considered an indication of future performance.

The market price for the trust units may not reflect the value of the net profits interests held by the trust.

The public trading price for the trust units tends to be tied to the recent and expected levels of cash distributions on the trust units. The amounts available for distribution by the trust vary in response to numerous factors outside the control of the trust or XTO Energy, including prevailing prices for oil and natural gas produced from the underlying properties. The market price of the trust units is not necessarily indicative of the value that the trust would realize if the net profits interests were sold to a third party buyer. In addition, such market price is not necessarily reflective of the fact that, since the assets of the trust are depleting assets, a portion of each cash distribution paid on the trust units should be considered by investors as a return of capital, with the remainder being considered as a return on investment. There is no guarantee that distributions made to a unitholder over the life of these depleting assets will equal or exceed the purchase price paid by the unitholder.

Oil and natural gas prices fluctuate due to a number of uncontrollable factors, and any decline will adversely affect the net proceeds payable to the trust and trust distributions.

The trust's monthly cash distributions are highly dependent upon the prices realized from the sale of natural gas and, to a lesser extent, oil. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the trust and XTO Energy. Factors that contribute to price fluctuations include instability in oil-producing regions, worldwide economic conditions, weather conditions, the supply and price of domestic and foreign oil, natural gas and natural gas liquids, consumer demand, the price and availability of alternative fuels, the proximity to, and capacity of, transportation facilities and the effect of worldwide energy conservation measures. Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices in the long term. Lower oil and natural gas prices may reduce the amount of oil and natural gas that is economic to produce and will reduce net profits available to the trust. The volatility of energy prices reduces the predictability of future cash distributions to trust unitholders.

Higher production expense and/or development costs, without concurrent increases in revenue, will directly decrease the net proceeds payable to the trust.

Production expense and development costs are deducted in the calculation of the trust's share of net proceeds. Accordingly, higher or lower production expense and development costs, without concurrent changes in revenue, will directly decrease or increase the amount received by the trust. If development costs and production expense for underlying properties in a particular state exceed the production proceeds from the properties (as was the case with respect to the properties underlying the Wyoming net profits interests in November and December 2007 and November 2008 and the properties underlying the Kansas net profits interests in October and November 2009), the trust will not receive net proceeds for those properties until future proceeds from production in that state exceed the total of the excess costs plus accrued interest during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs.

Proved reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions could cause the quantities and net present value of the reserves to be overstated.

Estimating proved oil and gas reserves is inherently uncertain. Petroleum engineers consider many factors and make assumptions in estimating reserves and future net cash flows. Those factors and assumptions include historical production from the area compared with production rates from similar producing areas, the effects of governmental regulation, assumptions about future commodity prices, production expense and development costs, taxes and capital expenditures, the availability of enhanced recovery techniques and relationships with landowners, working interest partners, pipeline companies and others. Lower oil and gas prices generally cause lower estimates of proved reserves. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variances could be material. Because the trust owns net profits interests, it does not own a specific percentage of the oil and gas reserves. Estimated proved reserves for the net profits interests are based on estimates of reserves for the underlying properties and an allocation method that considers estimated future net proceeds and oil and gas prices. Because trust reserve quantities are determined using an allocation formula, increases or decreases in oil and gas prices can significantly affect estimated reserves of the net profits interests.

Operational risks and hazards associated with the development of the underlying properties may decrease trust distributions.

There are operational risks and hazards associated with the production and transportation of oil and natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of oil or natural gas, releases of other hazardous materials, mechanical failures, cratering, and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, damage to the environment or natural resources, or cleanup obligations. The operation of oil and gas properties is also subject to various laws and regulations. Non-compliance with such laws and regulations could subject the operator to additional costs, sanctions or liabilities. The uninsured costs resulting from any of the above or similar occurrences could be deducted as a production expense or development cost in calculating the net proceeds payable to the trust, and would therefore reduce trust distributions by the amount of such uninsured costs.

Cash held by the trustee is not fully insured by the Federal Deposit Insurance Corporation, and future royalty income may be subject to risks relating to the creditworthiness of third parties.

Currently, cash held by the trustee as a reserve for liabilities and for the payment of expenses and distributions to unitholders is invested in Bank of America, N.A. certificates of deposit which are backed by the good faith and credit of Bank of America, N.A., but are only insured by the Federal Deposit Insurance Corporation up to $250,000. Each unitholder should independently assess the creditworthiness of Bank of America, N.A. For more information about the credit rating of Bank of America, N.A., please refer to its periodic filings with the SEC. The trust does not lend money and has limited ability to borrow money, which the trustee believes limits the trust's risk from the currently tight credit markets. The trust's future royalty income, however, may be subject to risks relating to the creditworthiness of the operators of the underlying properties and other purchasers of crude oil and natural gas produced from the underlying properties, as well as risks associated with fluctuations in the price of crude oil and natural gas. Information contained in Bank of America N.A.'s periodic filings with the SEC is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report or any other filing that the trust makes with the SEC.

Trust unitholders and the trustee have no influence over the operations on, or future development of, the underlying properties.

Neither the trustee nor the trust unitholders can influence or control the operation or future development of the underlying properties. The failure of an operator to conduct its operations or discharge its obligations in a proper manner could have an adverse effect on the net proceeds payable to the trust. Although XTO Energy and other operators of the underlying properties must adhere to the standard of a prudent operator, they are under no obligation to continue operating the properties. Neither the trustee nor trust unitholders have the right to replace an operator.

The assets of the trust represent interests in depleting assets and, if XTO Energy or any other operators developing the underlying properties do not perform additional successful development projects, the assets may deplete faster than expected. Eventually, the assets of the trust will cease to produce in commercial quantities and the trust will cease to receive proceeds from such assets.

The net proceeds payable to the trust are derived from the sale of hydrocarbons from depleting assets. The reduction in proved reserve quantities is a common measure of the depletion. Future maintenance and development projects on the underlying properties will affect the quantity of proved reserves and can offset the reduction in proved reserves. The timing and size of these projects will depend on the market prices of oil and natural gas. If the operator(s) of the properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the trust. Because the net proceeds payable to the trust are derived from the sale of hydrocarbons from depleting assets, the portion of distributions to unitholders attributable to depletion may be considered a return on capital as opposed to a return on investment. Distributions that are a return of capital will ultimately diminish the depletion tax benefits available to the unitholders, which could reduce the market value of the units over time. Eventually, the properties underlying the trust's net profits interest will cease to produce in commercial quantities and the trust will, therefore, cease to receive any net proceeds therefrom.

Terrorism and continued geopolitical hostilities could adversely affect trust distributions or the market price of the trust units.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism and other geopolitical hostilities could adversely affect trust distributions or the market price of the trust units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in oil and natural gas prices, or the possibility that the infrastructure on which the operators of the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

XTO Energy may transfer its interest in the underlying properties without the consent of the trust or the trust unitholders.

XTO Energy may at any time transfer all or part of its interest in the underlying properties to another party. Neither the trust nor the trust unitholders are entitled to vote on any transfer of the properties underlying the trust's net profits interests, and the trust will not receive any proceeds of any such transfer. Following any transfer, the transferred property will continue to be subject to the net profits interests of the trust, but the calculation, reporting and remitting of net proceeds to the trust will be the responsibility of the transferee.

XTO Energy or any other operator of any underlying property may abandon the property, thereby terminating the related net profits interest payable to the trust.

XTO Energy or any other operator of the underlying properties, or any transferee thereof, may abandon any well or property without the consent of the trust or the trust unitholders if they reasonably believe that the well or property can no longer produce in commercially economic quantities. This could result in the termination of the net profits interest relating to the abandoned well or property.

The net profits interests can be sold and the trust would be terminated.

The trust may sell the net profits interests if the holders of 80% or more of the trust units approve the sale or vote to terminate the trust. The trust will terminate if it fails to generate gross proceeds from the underlying properties of at least $1,000,000 per year over any consecutive two-year period. Sale of all of the net profits interests will terminate the trust. The net proceeds of any sale must be for cash with the proceeds promptly distributed to the trust unitholders.

Trust unitholders have limited voting rights and have limited ability to enforce the trust's rights against XTO Energy or any other operator of the underlying properties.

The voting rights of a trust unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of trust unitholders or for an annual or other periodic re-election of the trustee. Additionally, trust unitholders have no voting rights in XTO Energy or Exxon Mobil Corporation.

The trust indenture and related trust law permit the trustee and the trust to sue XTO Energy or any other operator of the underlying properties to compel them to fulfill the terms of the conveyance of the net profits interests. If the trustee does not take appropriate action to enforce provisions of the conveyance, the recourse of the trust unitholders would likely be limited to bringing a lawsuit against the trustee to compel the trustee to take specified actions. Trust unitholders probably would not be able to sue XTO Energy or any other operator of the underlying properties.

Financial information of the trust is not prepared in accordance with U.S. GAAP.

The financial statements of the trust are prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles, or U.S. GAAP. Although this basis of accounting is permitted for royalty trusts by the Securities and Exchange Commission, the financial statements of the trust differ from U.S. GAAP financial statements because net profits income is not accrued in the month of production, expenses are not recognized when incurred and cash reserves may be established for certain contingencies that would not be recorded in U.S. GAAP financial statements.

The limited liability of trust unitholders is uncertain.

The trust unitholders are not protected from the liabilities of the trust to the same extent that a shareholder would be protected from a corporation's liabilities. The structure of the trust does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to trust unitholders. While the trustee is liable for any excess liabilities incurred if the trustee fails to ensure that such liabilities are to be satisfied only out of trust assets, under the laws of Texas, which are unsettled on this point, a unitholder may be jointly and severally liable for any liability of the trust if the satisfaction of such liability was not contractually limited to the assets of the trust and the assets of the trust and the trustee are not adequate to satisfy such liability. As a result, trust unitholders may be exposed to personal liability. The trust, however, is not liable for production costs or other liabilities of the underlying properties.

Drilling oil and natural gas wells is a high-risk activity and subjects the trust to a variety of factors that it cannot control.

Drilling oil and natural gas wells involves numerous risks, including the risk that commercially productive oil and natural gas reservoirs are not encountered. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause drilling activities to be unsuccessful. In addition, there is often uncertainty as to the future cost or timing of drilling, completing and operating wells. Further, development activities may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- title problems;
- restricted access to land for drilling or laying pipeline;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions; and
- costs of, or shortages or delays in the availability of, drilling rigs, tubular materials and equipment.

While these risks do not expose the trust to liabilities of the drilling contractor or operator of the well, they can reduce net proceeds payable to the trust and trust distributions by decreasing oil and gas revenues or increasing production expense or development costs from the underlying properties. Furthermore, these risks may cause the costs of development activities on the underlying properties to exceed the revenues therefrom, thereby reducing net proceeds payable to the trust and trust distributions.

The underlying properties are subject to complex federal, state and local laws and regulations that could adversely affect net proceeds payable to the trust and trust distributions.

Extensive federal, state and local regulation of the oil and natural gas industry significantly affects operations on the underlying properties. In particular, oil and natural gas development and production are subject to stringent environmental regulations. These regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning oil and natural gas wells and other related facilities, which costs could reduce net proceeds payable to the trust and trust distributions. These regulations may become more demanding in the future.

Item 1B. *Unresolved Staff Comments*

The trust did not have any unresolved comments received more than 180 days prior to December 31, 2010 from the Securities and Exchange Commission staff; however, as of December 31, 2010, the trust did have one outstanding comment which the trust does not believe to be material. This comment seeks further analysis with respect to the trust's position that gas sales contracts entered into by the operator of the properties underlying the trust's net profits interest are not required to be filed as exhibits to the trust's reports. The trust has provided the requested analysis. For more information on the terms of these contracts, see Significant Properties, under Item 2.

Item 2. *Properties*

The net profits interests are the principal asset of the trust. The trustee cannot acquire any other assets, with the exception of certain short-term investments as specified under Item 1, Business. The trustee may sell or otherwise dispose of all or any part of the net profits interests if approved by at least 80% of the unitholders, or upon termination of the trust. Otherwise, the trust may only sell up to 1% of the value of the net profits interests in any calendar year, pursuant to notice from XTO Energy of its desire to sell the related underlying properties. Any such sale must be for cash with the proceeds promptly distributed to the unitholders. All the underlying properties are currently owned by XTO Energy. XTO Energy may sell all or any portion of the underlying properties at any time, subject to and burdened by the net profits interests.

The underlying properties are predominantly gas-producing properties with established production histories in the Hugoton area of Oklahoma and Kansas, the Anadarko Basin of Oklahoma and the Green River Basin of Wyoming. The average reserve-to-production index for the underlying properties as of December 31, 2010 is approximately 14 years. This index is calculated using total proved reserves and estimated 2011 production for the underlying properties. The projected 2011 production is from proved developed producing reserves as of December 31, 2010. Based on estimated future net cash flows at 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period, the proved reserves of the underlying properties are approximately 87% natural gas and 13% oil. XTO Energy operates approximately 94% of the underlying properties.

Because the underlying properties are working interests, production expense, development costs and overhead are deducted in calculating net profits income. As a result, net profits income is affected by the level of maintenance and development activity on the underlying properties. See Trustee's Discussion and Analysis of Financial Condition and Results of Operations, under Item 7. Total 2010 development costs deducted for the underlying properties were $7 million, a decrease of 65% from the prior year. XTO Energy has informed the trustee that total 2011 budgeted development costs for the underlying properties are between $10 million and $12 million.

Significant Properties

Hugoton Area

Natural gas was discovered in the Hugoton area in 1922. With an estimated five million productive acres covering parts of Texas, Oklahoma and Kansas, the Hugoton area is one of the largest domestic natural gas producing areas. During 2010, daily sales volumes from the underlying properties in the Hugoton area averaged approximately 18,900 Mcf of gas and 116 Bbls of oil.

Most of the production from the underlying properties in the Hugoton area is from the Chase formation. XTO Energy has informed the trustee that it has begun to develop other formations that underlie the 79,500 net acres held by production by the Chase formation wells, which include the Council Grove, Morrow, Chester and St. Louis formations. These formations are characterized by both oil and gas production from a variety of structural and stratigraphic traps. Since 2003, XTO Energy has drilled wells to these formations and plans to continue this development program in 2011.

Within this area, XTO Energy drilled 2 gross (2.0 net) wells and performed 10 workovers in 2010. XTO Energy has informed the trustee that it plans to drill up to 2 new wells and perform up to 20 workovers during 2011.

XTO Energy's future development plans for the underlying properties in the Hugoton area include:

- additional compression to lower line pressures,
- installing artificial lift,
- opening new producing zones in existing wells,
- restimulating producing intervals in existing wells utilizing new technology,
- deepening existing wells to new producing zones, and
- drilling additional wells.

XTO Energy delivers most of its Hugoton gas production to a gathering and processing system owned by a subsidiary. Most of the gas is sold under the terms of a contract that was entered into in March 1996, predating the existence of the trust. This system collects the majority of its throughput from underlying properties, which, in recent months, has been approximately 13,000 Mcf per day. The gathering subsidiary purchases the gas from XTO Energy at the wellhead, gathers and transports the gas to its plant, and treats and processes the gas at the plant. The gathering subsidiary pays XTO Energy for wellhead volumes at a price of 80% to 85% of the net residue price received by XTO Energy's marketing affiliate, which amount is adjusted for the BTU content of the gas. This affiliate currently sells the residue to a pipeline at a price based on a monthly pipeline index less actual third party fees.

Other Hugoton gas production is sold under a third party contract. Under the contract, XTO Energy receives 74.5% of the net proceeds received from the sale of the residue gas and liquids.

Anadarko Basin

Oil and gas accumulations were discovered in the Anadarko Basin of western Oklahoma in 1945. XTO Energy is one of the largest producers in the Ringwood, Northwest Okeene and Cheyenne Valley fields of Major County, the Northeast Cedardale field of Woodward County and the Elk City field of Beckham County, the principal producing regions of the underlying properties in the Anadarko Basin. Daily sales volumes from the underlying properties in the Anadarko Basin averaged 29,300 Mcf of gas and 582 Bbls of oil in 2010.

The fields in the Major County area are characterized by oil and gas production from a variety of structural and stratigraphic traps. Productive zones include the Oswego, Red Fork, Inola, Chester, Manning, Mississippian, Hunton and Arbuckle formations. Within this area, XTO Energy drilled 1 gross (0.7 net) well and performed 7 workovers in 2010. XTO Energy has informed the trustee that it plans to drill up to 2 new wells and perform up to 12 workovers in Major County during 2011.

The fields within Woodward County are characterized primarily by gas production from a variety of structural and stratigraphic traps. Productive zones include the Cottage Grove, Oswego, Chester and Mississippian formations. Within this area, XTO Energy did not drill any wells or perform any workovers in 2010. XTO Energy has informed the trustee that it does not plan to drill any new wells but perform up to 4 workovers in Woodward County during 2011.

The Elk City field on the eastern edge of Beckham County produces oil and gas from a structural anticline with stratigraphic trapping features. Production zones include the Hoxbar, Atoka and Morrow formations. Within this area, XTO Energy did not drill any wells but did perform 1 workover in 2010. XTO Energy has informed the trustee that it plans to drill 1 new well and perform up to 2 workovers within the Elk City field during 2011.

XTO Energy plans to further develop the underlying properties in the Anadarko Basin primarily through:

- mechanical stimulation of existing wells,
- installing artificial lift,
- opening new producing zones in existing wells,
- deepening existing wells to new producing zones, and
- drilling additional wells.

A gathering subsidiary of XTO Energy operates a 300-mile gathering system and pipeline in the Major County area. The gathering subsidiary and a third-party processor purchase natural gas produced at the wellhead from XTO Energy and other producers in the area under various agreements, most of which were entered into in the 1960's and 1970's, and which include life-of-production terms. The gathering subsidiary gathers and transports the gas to a third-party processor, which processes the gas and pays XTO Energy and other producers for at least 50% of the liquids processed based upon a weighted average sales price. After the gas is processed, the gathering subsidiary transports the gas via a residue pipeline to a connection with an interstate pipeline. The gathering subsidiary sells the residue gas to the marketing subsidiary of XTO Energy based upon a weighted average price. The gathering subsidiary pays this price to XTO Energy less a compression and gathering fee of approximately $0.31 per Mcf of residue gas. This gathering fee was previously approved by the Federal Energy Regulatory Commission when the gathering subsidiary was regulated. During 2010, the gathering system collected approximately 10,000 Mcf per day, approximately 50% of which XTO Energy operates. Estimated capacity of the gathering system is 24,000 Mcf per day. The gathering subsidiary also provides contract operating services to properties in Woodward County, collecting approximately 10,000 Mcf per day, for an average fee of approximately $0.05 per Mcf. XTO Energy also sells gas directly to its marketing subsidiary, which then sells the gas to third parties. The price paid to XTO Energy is based upon the weighted average price of several published indices, but does not include a deduction for any marketing fees. The price paid by the marketing affiliate includes a deduction for any transportation fees charged by the third party.

Green River Basin

The Green River Basin is located in southwestern Wyoming. Natural gas was discovered in the Fontenelle Field of the Green River Basin in the early 1970's. The producing reservoirs are the Frontier, Baxter and Dakota sandstones.

Daily 2010 sales volumes from the underlying properties in the Fontenelle Field averaged 17,800 Mcf of natural gas and 33 Bbls of oil. In 2010, XTO Energy did not drill any wells but did perform 1 workover. XTO Energy has advised the trustee that it does not plan to drill any new wells but may perform up to 4 workovers in the Green River Basin during 2011. XTO Energy has advised the trustee that it is continuing its efforts to reduce pipeline pressure which has shown potential for increasing production and extending field life in the Fontenelle Field.

Potential development activities for the underlying properties in this area include:

- installing artificial lift,
- restimulating producing intervals utilizing new technology,
- additional compression to lower line pressures, and
- opening new producing zones in existing wells.

XTO Energy markets the gas produced from the Fontenelle Unit and nearby properties under various marketing arrangements. Under the agreement covering the majority of the gas sold, XTO Energy compresses the gas on the lease, transports it off the lease and compresses the gas again prior to entry into the gas plant pipeline. The pipeline transports the gas to the gas plant, where the gas is processed, then redelivered to XTO Energy. The owner of the gas plant and related pipeline charges XTO Energy for operational fuel and processing. In 2010, the fuel charge was 1.89% of the volumes produced and the processing fee was approximately $0.11 per MMBtu. XTO Energy transports and sells this gas directly to the markets based on a spot sales price. The gas not sold under the above arrangement is sold either under a similar arrangement where the fee is approximately $0.17 per MMBtu, or under a contract where XTO Energy directly sells the gas to a third party on the lease at an adjusted index price. Condensate is sold at the lease to an independent third party at market rates.

Producing Acreage, Drilling and Well Counts

For the following data, ‘‘gross’’ refers to the total wells or acres on the underlying properties in which XTO Energy owns a working interest and ‘‘net’’ refers to gross wells or acres multiplied by the percentage working interest owned by XTO Energy. Although many of XTO Energy’s wells produce both oil and gas, a well is categorized as an oil well or a gas well based upon the ratio of oil to natural gas production. Operated wells are managed by XTO Energy, while nonoperated wells are managed by others.

The underlying properties are interests in developed properties located primarily in gas producing regions of Kansas, Oklahoma and Wyoming. The following is a summary of the approximate producing acreage of the underlying properties at December 31, 2010. Undeveloped acreage is not significant.

	Gross	Net
Hugoton Area	212,725	197,623
Anadarko Basin	174,295	134,607
Green River Basin	37,912	28,626
Total	424,932	360,856

The following is a summary of the producing wells on the underlying properties as of December 31, 2010:

	Operated Wells		Nonoperated Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Gas	1,252.0	1,109.9	290.0	66.4	1,542.0	1,176.3
Oil	40.0	35.4	8.0	1.4	48.0	36.8
Total	1,292.0	1,145.3	298.0	67.8	1,590.0	1,213.1

The following is a summary of the number of wells drilled on the underlying properties during the years indicated. No exploratory wells were drilled on the underlying properties in the periods indicated; all wells drilled were developmental. There were 3 gross (0.8 net) wells in process of drilling at December 31, 2010.

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Completed gas wells	3	2.7	9	5.1	54	35.0
Completed oil wells	—	—	1	1.0	1	0.1
Dry wells	—	—	—	—	—	—
Total[(a)]	3	2.7	10	6.1	55	35.1

(a) Included in totals are zero wells in 2010, 5 gross (1.2 net) wells in 2009 and 14 gross (2.6 net) wells in 2008, drilled on nonoperated interests.

Estimated Proved Reserves and Future Net Cash Flows

The following are proved reserves of the underlying properties, as estimated by independent engineers, and proved reserves and future net cash flows from proved reserves of the net profits interests, based on an allocation of these reserves, at December 31, 2010:

	Underlying Properties		Net Profits Interests			
	Proved Reserves[(a)]		Proved Reserves[(a)(b)]		Future Net Cash Flows from Proved Reserves[(a)(c)]	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Undiscounted	Discounted
(in thousands)						
Oklahoma	205,530	2,561	97,024	1,206	$503,256	$253,764
Wyoming	85,680	102	30,408	37	108,105	56,082
Kansas	23,784	198	11,004	93	52,402	29,825
TOTAL	314,994	2,861	138,436	1,336	$663,763	$339,671

(a) Based on 12-month average oil price of $75.91 per Bbl and $4.45 per Mcf for gas, based on the first-day-of-the-month price for each month in the period. Discounted estimated future net cash flows from proved reserves increased 54% from year-end 2009 to 2010, primarily because of a 36% increase in natural gas prices and a 33% increase in oil prices.

(b) Since the trust has defined net profits interests, the trust does not own a specific percentage of the oil and gas reserves. Because trust reserve quantities are determined using an allocation formula, any fluctuations in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the net profits interests.

(c) Before income taxes since future net cash flows are not subject to taxation at the trust level. Future net cash flows are discounted at an annual rate of 10%.

Proved reserves consist of the following:

	Underlying Properties		Net Profits Interests	
	Proved Reserves		Proved Reserves	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
(in thousands)				
Proved developed reserves	276,089	2,513	126,349	1,218
Proved undeveloped reserves	38,905	348	12,087	118
Total proved reserves	314,994	2,861	138,436	1,336

Approximately 88% of the underlying proved reserves are proved developed reserves.

The process of estimating oil and gas reserves is complex and requires significant judgment as discussed in Item 1A, Risk Factors, and is performed by XTO Energy. As a result, XTO Energy has developed internal policies and controls for estimating and recording reserves. XTO Energy's policies regarding booking reserves require proved reserves to be in compliance with the SEC definitions and guidance. XTO Energy's policies assign responsibilities for compliance in reserves bookings to its reserve engineering group and require that reserve estimates be made by qualified reserves estimators, as defined by the Society of Petroleum Engineers' standards. All qualified reserves estimators are required to receive education covering the fundamentals of SEC proved reserves assignments.

The XTO Energy reserve engineering group reviews reserve estimates with our third-party petroleum consultants, Miller and Lents, Ltd., independent petroleum engineers. Miller and Lents, Ltd. estimated oil and gas reserves attributable to the underlying properties as of December 31, 2010, 2009, 2008 and 2007. Miller and Lents' primary technical person responsible for calculating the trust's reserves has more than 30 years of experience as a reserve engineer. The estimated reserves for the underlying properties are then used by XTO Energy to calculate the estimated oil and gas reserves attributable to the net profits interests. Numerous uncertainties are inherent in estimating reserve volumes and values, and such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimates.

Reserve quantities and revenues for the net profits interests were estimated from projections of reserves and revenues attributable to the combined interests of the trust and XTO Energy in the subject properties. Since the trust has defined net profits interests, the trust does not own a specific percentage of the oil and gas reserve quantities. Accordingly, reserves allocated to the trust pertaining to its 80% net profits interests in the properties have effectively been reduced to reflect recovery of the trust's 80% portion of applicable production and development costs. Because trust reserve quantities are determined using an allocation formula, any fluctuations in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the net profits interests.

Oil and Natural Gas Production

Trust production is recognized in the period net profits income is received, which is the month following receipt by XTO Energy, and generally two months after the time of production. Oil and gas production and average sales prices attributable to the underlying properties and the net profits interests for each of the three years ended December 31, 2010 were as follows:

	2010	2009	2008
Production			
Underlying Properties			
Gas – Sales (Mcf)	**24,074,923**	26,641,595	28,176,094
Average per day (Mcf)	**65,959**	72,991	76,984
Oil – Sales (Bbls)	**266,656**	260,499	341,754
Average per day (Bbls)	**731**	714	934
Net Profits Interests			
Gas – Sales (Mcf)	**12,455,292**	8,326,148	13,134,564
Average per day (Mcf)	**34,124**	22,811	35,887
Oil – Sales (Bbls)	**140,544**	90,552	169,915
Average per day (Bbls)	**385**	248	464
Average Sales Price			
Gas (per Mcf)	**$ 4.72**	$ 3.38	$ 7.75
Oil (per Bbl)	**$ 73.77**	$ 54.10	$ 104.62

Oil and gas production by conveyance attributable to the underlying properties for each of the three years ended December 31, 2010 were as follows:

	Underlying Gas Production (Mcf)		
Conveyance	**2010**	**2009**	**2008**
Kansas	**2,323,436**	2,130,093	2,250,447
Oklahoma	**15,268,280**	17,344,457	18,372,867
Wyoming	**6,483,207**	7,167,045	7,552,780
Total	**24,074,923**	26,641,595	28,176,094

	Underlying Oil Production (Bbls)		
Conveyance	**2010**	**2009**	**2008**
Kansas	**34,462**	12,858	12,861
Oklahoma	**220,149**	230,838	313,159
Wyoming	**12,045**	16,803	15,734
Total	**266,656**	260,499	341,754

Pricing and Sales Information

A subsidiary of XTO Energy purchases most of XTO Energy's natural gas production based on a weighted average sales price, then sells the gas to third parties for the best available price. Oil production is generally marketed at the wellhead to third parties at the best available price. XTO Energy arranges for some of its natural gas to be processed by unaffiliated third parties and markets the natural gas liquids. Most of the natural gas attributable to the underlying properties is marketed under contracts existing at trust inception. Contracts covering production from the Ringwood area of the Major County area are generally for the life of the lease, and the contract for the majority of production from the Hugoton area was extended through 2011. If new contracts are entered with unaffiliated third parties, the proceeds from sales under those new contracts will be included in gross proceeds from the underlying properties. If new contracts are entered with XTO Energy's marketing subsidiary, it may charge XTO Energy a fee that may not exceed 2% of the sales price of the oil and natural gas received from unaffiliated parties. The sales price is net of any deductions for transportation from the wellhead to the unaffiliated parties and any gravity or quality adjustments. For further information on these arrangements see Significant Properties above.

Regulation

Natural Gas Regulation

The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation and storage rates charged, tariffs, and various other matters, by the Federal Energy Regulatory Commission. Federal price controls on wellhead sales of domestic natural gas terminated on January 1, 1993. While natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act, including enforcement rules and new annual reporting requirements for certain sellers of natural gas. It is impossible to predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, such proposals might have on the operations of the underlying properties.

Federal Regulation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances.

On December 19, 2007, the President signed into law the Energy Independence & Security Act of 2007 (PL 110-140). The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations, and establishes penalties for violations thereunder. XTO Energy has advised the trustee that it cannot predict the impact of future government regulation on any crude oil, condensate or natural gas liquids facilities, sales or transportation transactions.

Environmental Regulation

Companies that are engaged in the oil and gas industry are affected by federal, state and local laws regulating the discharge of materials into the environment. Those laws may impact operations of the underlying properties. No material expenses have been incurred on the underlying properties in complying with environmental laws and regulations. XTO Energy does not expect that future compliance will have a material adverse effect on the trust.

There is an increased focus by local, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change. Several states have adopted climate change legislation and regulations, and various other regulatory bodies have announced their intent to regulate GHG emissions or adopt climate change regulations. As these regulations are under development, XTO Energy is unable to predict the total impact of the potential regulations upon the operators of the underlying properties, and it is possible that operators of the underlying properties could face increases in operating costs in order to comply with climate change or GHG emissions legislation, which costs could reduce net proceeds payable to the trust and trust distributions.

State Regulation

The various states regulate the production and sale of oil and natural gas, including imposing requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rates of production may be regulated and the maximum daily production allowables from both oil and gas wells may be established on a market demand or conservation basis, or both.

State Tax Withholding

Several states have enacted legislation to require state income tax withholding from nonresident recipients of oil and gas proceeds. After consultation with its state tax counsel, XTO Energy has advised the trustee that it believes the trust is not subject to these withholding requirements. However, regulations are subject to change by the various states, which could change this conclusion. Should the trust be required to withhold state taxes, distributions to the unitholders would be reduced by the required amount, subject to the unitholder's right to file a state tax return to claim any refund due.

Other Regulation

The Minerals Management Service of the United States Department of the Interior amended the crude oil valuation regulations in July 2004 and the natural gas valuation regulations in June 2005 for oil and natural gas produced from federal oil and natural gas leases. The principal effect of the oil regulations pertains to which published market prices are most appropriate to value crude oil not sold in an arm's-length transaction and what transportation deductions should be allowed. The principal effect of the natural gas valuation regulations pertains to the calculation of transportation deductions and changes necessitated by judicial decisions since the regulations were last amended. Seven percent of the net acres of the underlying properties, primarily located in Wyoming, involve federal leases. Neither of these changes have had a significant effect on trust distributions.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws, including, but not limited to, regulations and laws relating to environmental protection, occupational safety, resource conservation and equal employment opportunity. XTO Energy has advised the trustee that it does not believe that compliance with these laws will have any material adverse effect upon the unitholders.

Item 3. *Legal Proceedings*

An amended petition for a class action lawsuit, *Beer, et al. v. XTO Energy Inc.*, was filed in January 2006 in the District Court of Texas County, Oklahoma by certain royalty owners of natural gas wells in Oklahoma and Kansas. The plaintiffs allege that XTO Energy has not properly accounted to the plaintiffs for the royalties to which they are entitled and seek an accounting regarding the natural gas and other products produced from their wells and the prices paid for the natural gas and other products produced, and for payment of the monies allegedly owed since June 2002, with a certain limited number of plaintiffs claiming monies owed for additional time. XTO Energy removed the case to federal district court in Oklahoma City. A hearing on the class certification was conducted in October 2008. At the class certification hearing, the plaintiffs sought to certify a class of royalty owners whose wells were connected to a processing plant owned by a subsidiary of XTO Energy in the Hugoton Field, with two sub-classes consisting of owners in Oklahoma and Kansas. In March 2009, the court granted the motion to certify the class. The plaintiffs filed a motion for summary judgment for only the two named plaintiffs. The court granted the motion in the amount of $12,779. A motion for summary judgment related to the remainder of the class was denied. Trial was scheduled for April 2010; however, the court vacated the trial date. At a hearing in April 2010, the court ruled that the class representatives were no longer proper representatives and stated that it was considering whether to dismiss class counsel or decertify the class in whole or in part. In a subsequent ruling in April 2010, the court decertified the class. In April 2010, new counsel and representative parties, Fankhouser and Goddard, filed a motion to intervene and prosecute the *Beer* class. This motion was granted on July 13, 2010. The new plaintiffs and counsel filed an amended complaint asserting new causes of action for breach of fiduciary duties and unjust enrichment. Following an additional class discovery period, a class certification hearing was held on September 27, 2010. On December 16, 2010, the court certified the class. XTO Energy has informed the trustee that it believes that it has strong defenses to this lawsuit and intends to vigorously defend its position. However, if XTO Energy ultimately makes any settlement payments or receives a judgment against it, the trust will bear its 80% share of such settlement or judgment related to production from the underlying properties. Additionally, if a judgment or settlement increases the amount of future payments to royalty owners, the trust would bear its proportionate share of the increased payments through reduced net proceeds. XTO Energy has informed the trustee that, although the amount of any reduction in net proceeds is not presently determinable, in its management's opinion, the amount is not currently expected to be material to the trust's annual distributable income, financial position or liquidity. It could, however, result in costs exceeding revenues on the properties underlying the Oklahoma and Kansas net profit interests for one or more monthly distributions, depending on the size of the judgment or settlement, if any, and the net proceeds being paid at that time.

In September 2008, a class action lawsuit was filed against XTO Energy styled *Wallace B. Roderick Revocable Living Trust, et al. v. XTO Energy Inc.* in the District Court of Kearny County, Kansas. XTO Energy removed the case to federal court in Wichita, Kansas. The plaintiffs allege that XTO Energy has improperly taken post-production costs from royalties paid to the plaintiffs from wells located in Kansas, Oklahoma and Colorado. The plaintiffs also seek to represent all royalty owners in these three states as a class. The plaintiffs' claims overlap the claims made by the plaintiffs in the *Beer/Fankhouser* case as to certain properties. XTO Energy has answered, denying all claims, and has filed motions to dismiss a portion of the claims. In January 2010, the federal court granted XTO Energy's motion for summary judgment concerning prior settled class actions that overlap plaintiffs' proposed class action. The court also granted XTO Energy's motion to dismiss those portions of plaintiffs' class that are currently being prosecuted in the *Beer/Fankhouser* class action discussed above. The *Roderick* plaintiffs have also filed a motion to include the former *Beer/Fankhouser* class into this litigation. The court denied the motion. The plaintiffs have filed a motion to certify the class. XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to this lawsuit and intends to vigorously defend its position. However, if XTO Energy ultimately makes any settlement payments or receives a judgment against it, the trust will bear its 80% share of such settlement or judgment related to production from the underlying properties. Additionally, if the judgment or settlement increases the amount of future payments to royalty owners, the trust would bear its proportionate share of the increased payments through reduced net proceeds. XTO Energy has informed the trustee that, although the amount of any reduction in net proceeds is not presently determinable, in its management's opinion, the amount is not currently expected to be material to the trust's annual distributable income, financial position or liquidity. It could, however, result in costs exceeding revenues on the properties underlying the Oklahoma and Kansas net profit interests for one or more monthly distributions, depending on the size of the judgment or settlement, if any, and the net proceeds being paid at that time.

Certain of the underlying properties are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. XTO Energy has advised the trustee that it does not believe that the ultimate resolution of these claims will have a material effect on trust annual distributable income, financial position or liquidity.

Item 4. ***[Removed and Reserved]***

PART II

Item 5. *Market for Units of the Trust, Related Unitholder Matters and Trust Purchases of Units*

Units of Beneficial Interest

The units of beneficial interest in the trust began trading on the New York Stock Exchange on April 9, 1999 under the symbol "HGT." The following are the high and low unit sales prices and total cash distributions per unit paid by the trust during each quarter of 2010 and 2009:

Quarter	Sales Price High	Sales Price Low	Distributions per Unit
2010			
First	**$18.65**	**$15.00**	**$0.414128**
Second	**22.13**	**16.58**	**0.468323**
Third	**21.39**	**18.01**	**0.363184**
Fourth	**21.65**	**19.39**	**0.305065**
			$1.550700
2009			
First	$18.08	$ 7.29	$0.136634
Second	15.02	9.26	0.106593
Third	19.05	11.96	0.209290
Fourth	18.40	15.45	0.280139
			$0.732656

At December 31, 2010, there were 40,000,000 units outstanding and approximately 964 unitholders of record; 39,372,541 of these units were held by depository institutions.

The trust has no equity compensation plans, nor has it purchased any units during the period covered by this report.

Item 6. *Selected Financial Data*

	Year Ended December 31 2010	2009	2008	2007	2006
Net Profits Income	**$ 62,883,206**	$ 30,180,880	$117,268,069	$ 70,499,584	$ 91,241,196
Distributable Income	**62,028,000**	29,306,240	116,494,400	69,388,520	90,910,760
Distributable Income per Unit	**1.550700**	0.732656	2.912360	1.734713	2.272769
Distributions per Unit	**1.550700**	0.732656	2.912360	1.734713	2.272769
Total Assets at Year-End	**129,222,886**	144,162,380	147,867,855	161,034,033	165,609,772

Item 7. *Trustee's Discussion and Analysis of Financial Condition and Results of Operations*

Calculation of Net Profits Income

The following is a summary of the calculation of net profits income received by the trust:

	Year Ended December 31[a]			Three Months Ended December 31[a]	
	2010	2009	2008	2010	2009
Sales Volumes					
Gas (Mcf)[b]					
Underlying properties	**24,074,923**	26,641,595	28,176,094	**5,958,663**	6,536,638
Average per day	**65,959**	72,991	76,984	**64,768**	71,050
Net profits interests	**12,455,292**	8,326,148	13,134,564	**2,712,500**	3,053,845
Oil (Bbls)[b]					
Underlying properties	**266,656**	260,499	341,754	**63,693**	54,739
Average per day	**731**	714	934	**692**	595
Net profits interests	**140,544**	90,552	169,915	**29,949**	26,195
Average Sales Prices					
Gas (per Mcf)	**$ 4.72**	$ 3.38	$ 7.75	**$ 4.18**	$ 3.45
Oil (per Bbl)	**$ 73.77**	$ 54.10	$ 104.62	**$ 74.46**	$ 78.90
Revenues					
Gas sales	**$113,571,616**	$ 90,049,682	$218,253,910	**$24,878,394**	$22,564,668
Oil sales	**19,670,776**	14,092,634	35,754,556	**4,742,506**	4,318,749
Total Revenues	**133,242,392**	104,142,316	254,008,466	**29,620,900**	26,883,417
Costs					
Taxes, transportation and other	**15,224,494**	13,849,086	23,271,226	**3,333,703**	3,664,113
Production expense	**21,086,979**	21,038,815	27,454,543	**5,580,756**	4,925,553
Development costs[c]	**7,250,000**	21,000,000	46,000,000	**2,550,000**	1,500,000
Overhead	**10,974,111**	10,628,875	9,830,861	**2,763,317**	2,728,359
Excess costs[d]	**102,800**	(100,560)	866,750	**—**	(100,560)
Total Costs	**54,638,384**	66,416,216	107,423,380	**14,227,776**	12,717,465
Net Proceeds	**78,604,008**	37,726,100	146,585,086	**15,393,124**	14,165,952
Net Profits Percentage	**80%**	80%	80%	**80%**	80%
Net Profits Income	**$ 62,883,206**	$ 30,180,880	$117,268,069	**$12,314,499**	$11,332,762

(a) Because of the two-month interval between time of production and receipt of net profits income by the trust: 1) oil and gas sales for the year ended December 31 generally relate to twelve months of production for the period November through October, and 2) oil and gas sales for the three months ended December 31 generally relate to production for the period August through October.

(b) Oil and gas sales volumes are allocated to the net profits interests based upon a formula that considers oil and gas prices and the total amount of production expense and development costs. Changes in any of these factors may result in disproportionate fluctuations in volumes allocated to the net profits interests. Therefore, comparative discussion of oil and gas sales volumes is based on the underlying properties.

(c) See Note 5 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

(d) See Note 4 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

Results of Operations

Years Ended December 31, 2010, 2009 and 2008

Net profits income for 2010 was $62,883,206, as compared with $30,180,880 for 2009 and $117,268,069 for 2008. The 108% increase in net profits income from 2009 to 2010 is primarily the result of higher oil and gas prices ($32.6 million) and decreased development costs ($11.0 million), partially offset by decreased gas production ($9.7 million). The 74% decrease in net profits income from 2008 to 2009 is primarily the result of lower oil and gas prices ($112.2 million) and decreased oil and gas production ($7.7 million), partially offset by lower development costs ($20.0 million), lower taxes, transportation and other costs ($7.5 million) and decreased production expense ($5.1 million). Approximately 85% in 2010, 84% in 2009 and 85% in 2008 of net profits income was derived from natural gas sales.

Trust administration expense was $856,314 in 2010 as compared to $875,105 in 2009 and $864,872 in 2008. Interest income was $1,108 in 2010, $465 in 2009 and $91,203 in 2008. Changes in interest income are attributable to fluctuations in net profits income and interest rates. Distributable income was $62,028,000 or $1.550700 per unit in 2010, $29,306,240 or $0.732656 per unit in 2009 and $116,494,400 or $2.912360 per unit in 2008.

Net profits income is recorded when received by the trust, which is the month following receipt by XTO Energy, and generally two months after oil and gas production. Net profits income is generally affected by three major factors:

- oil and gas sales volumes,
- oil and gas sales prices, and
- costs deducted in the calculation of net profits income.

Volumes

From 2009 to 2010, underlying gas sales volumes decreased 10% due to natural production decline and the timing of cash receipts, partially offset by increased production from new wells and workovers. Underlying oil sales volumes increased 2% from 2009 to 2010 primarily because of increased production from new wells and workovers, partially offset by natural production decline and the timing of cash receipts. From 2008 to 2009, underlying gas sales volumes decreased 5% due to natural production decline, partially offset by the timing of cash receipts and increased production from new wells and workovers. Underlying oil sales volumes decreased 24% from 2008 to 2009 primarily because of the timing of cash receipts and natural production decline, partially offset by increased production from new wells and workovers.

The rate of natural production decline on the underlying oil and gas properties is approximately 6% to 8% a year.

Prices

Gas. The 2010 average gas price was $4.72 per Mcf, a 40% increase from the 2009 average gas price of $3.38 per Mcf, which was 56% lower than the 2008 average gas price of $7.75 per Mcf. Natural gas prices are affected by the level of North American production, weather, crude oil and natural gas liquids prices, the U.S. economy, storage levels and import levels of liquefied natural gas. Natural gas prices are expected to remain volatile. The average NYMEX price for November 2010 through January 2011 was $4.06 per MMBtu. Recent trust gas prices have averaged approximately 10% higher than the NYMEX price. At February 14, 2011, the average NYMEX gas price for the following 12 months was $4.31 per MMBtu.

Oil. The average oil price for 2010 was $73.77 per Bbl, 36% higher than the average oil price for 2009 of $54.10 per Bbl, which was 48% lower than the average oil price for 2008 of $104.62 per Bbl. Oil prices are expected to remain volatile. The average NYMEX price for November 2010 through January 2011 was $87.77 per Bbl. At February 14, 2011, the average NYMEX oil price for the following 12 months was $95.00 per Bbl. Recent trust oil prices have averaged approximately 4% lower than the NYMEX price.

Costs

The calculation of net profits income includes deductions for production expense, development costs and overhead since the related underlying properties are working interests. If monthly costs exceed revenues for any state, these excess costs must be recovered, with accrued interest, from future net proceeds of that state and cannot reduce net profits income from another state. See ''Excess costs'' below.

Taxes, transportation and other. Taxes, transportation and other generally fluctuates with changes in total revenues. Taxes, transportation and other increased 10% from 2009 to 2010 primarily because of increased production taxes related to higher revenues, partially offset by decreased property taxes. Taxes, transportation and other decreased 40% from 2008 to 2009 primarily because of decreased production taxes related to lower revenues, partially offset by increased other deductions as a percentage of oil and gas revenues.

Production. Production expense remained relatively flat from 2009 to 2010 as increased repairs and maintenance and fuel costs were offset by decreased compressor rentals and outside operated costs. Production expense decreased 23% from 2008 to 2009 primarily because of decreased repairs and maintenance, location and power and fuel costs.

Development. Development costs deducted were $7.3 million in 2010, $21.0 million in 2009 and $46.0 million in 2008. In 2010, actual development costs were $9.0 million. At December 31, 2010, cumulative actual costs exceeded cumulative budgeted costs by approximately $0.8 million. The monthly development cost deduction was $3.75 million from the January 2008 distribution through the August 2008 distribution. Due to higher than anticipated costs as a result of the timing of expenditures, the monthly development cost deduction was increased to $4.0 million beginning with the September 2008 distribution and was maintained at that level through the March 2009 distribution. As a result of decreased development activity and revisions to the 2009 development budget, the development cost deduction was decreased to $2.0 million beginning with the April 2009 distribution, to $1.0 million beginning with the June 2009 distribution and to $500,000 beginning with the September 2009 distribution and was maintained at that level through the July 2010 distribution. As a result of increased development activity, the development cost deduction was increased to $600,000 beginning with the August 2010 distribution and to $850,000 beginning with the October 2010 distribution and was maintained at that level through the remainder of 2010. For further information on 2011 budgeted development costs, see Properties, under Item 2. The monthly deduction is based on the current level of development expenditures, budgeted future development costs and the cumulative actual costs under (over) previous deductions. XTO Energy has advised the trustee that this monthly deduction will continue to be evaluated and revised as necessary.

Overhead. Overhead is charged by XTO Energy for administrative expenses incurred to support operations of the underlying properties. Overhead fluctuates based on changes in the active well count and drilling activity on the underlying properties, as well as an annual cost level adjustment.

Excess costs. Costs exceeded revenues by $513,475 ($410,780 net to the trust) on properties underlying the Kansas net profits interests in October and November 2009. Lower gas prices caused costs to exceed revenues on properties underlying the Kansas net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the partial recovery of excess costs of $410,957 ($328,766 net to the trust), plus accrued interest of $1,958 ($1,566 net to the trust) in December 2009 and the full recovery of excess costs of $102,518 ($82,014 net to the trust), plus accrued interest of $282 ($226 net to the trust) in January 2010.

Costs exceeded revenues by $970,780 ($776,624 net to the trust) on properties underlying the Wyoming net profits interests in November 2008. Lower gas prices caused costs to exceed revenues on properties underlying the Wyoming net profits interest, however, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the full recovery of excess costs, plus accrued interest of $3,192 ($2,554 net to the trust) in December 2008.

Costs exceeded revenues by $853,468 ($682,774 net to the trust) on properties underlying the Wyoming net profits interests in November and December 2007. Lower gas prices caused costs to exceed revenues on properties underlying the Wyoming net profits interest, however, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the full recovery of excess costs, plus accrued interest of $10,090 ($8,072 net to the trust) in February 2008.

There were no excess costs as of December 31, 2010.

Fourth Quarter 2010 and 2009

During fourth quarter 2010 the trust received net profits income totaling $12,314,499 compared with fourth quarter 2009 net profits income of $11,332,762. This 9% increase in net profits income was primarily due to higher gas prices ($3.8 million) and increased oil production ($0.5 million), partially offset by decreased gas production ($1.9 million), higher development costs ($0.8 million) and increased production expense ($0.6 million).

Administration expense was $112,267 and interest income was $368, resulting in fourth quarter 2010 distributable income of $12,202,600 or $0.305065 per unit. Distributable income for fourth quarter 2009 was $11,205,560 or $0.280139 per unit. Distributions to unitholders for the quarter ended December 31, 2010 were:

Record Date	Payment Date	Per Unit
October 29, 2010	November 15, 2010	$0.116577
November 30, 2010	December 14, 2010	0.082760
December 31, 2010	January 14, 2011	0.105728
		$0.305065

Volumes

Fourth quarter underlying gas sales volumes decreased 9% and underlying oil sales volumes increased 16% from 2009 to 2010. Gas sales volumes decreased primarily because of natural production decline and the timing of cash receipts, partially offset by increased production from new wells and workovers. Oil sales volumes increased primarily because of increased production from new wells and workovers, partially offset by the timing of cash receipts and natural production decline.

The rate of natural production decline on the underlying oil and gas properties is approximately 6% to 8% a year.

Prices

The average fourth quarter 2010 gas price was $4.18 per Mcf, or 21% higher than the fourth quarter 2009 average price of $3.45 per Mcf. The average fourth quarter 2010 oil price was $74.46 per Bbl, or 6% lower than the fourth quarter 2009 average price of $78.90 per Bbl. For further information about product prices, see "Years Ended December 31, 2010, 2009 and 2008 – Prices" above.

Costs

Taxes, transportation and other. Taxes, transportation and other generally fluctuates with changes in total revenues. Taxes, transportation and other decreased 9% from 2009 to 2010 primarily due to lower property taxes, partially offset by increased production taxes related to higher revenues.

Production. Fourth quarter production expense increased 13% from 2009 to 2010 primarily because of increased repairs and maintenance, compressor rentals and location costs.

Development. Development costs, which were deducted based on budgeted development costs, increased 70% from fourth quarter 2009 to 2010 primarily because of increased development activity.

Overhead. Overhead increased 1% from fourth quarter 2009 to 2010 primarily because of the annual rate adjustment based on an oil and gas industry index.

Excess costs. Costs exceeded revenues by $513,475 ($410,780 net to the trust) on properties underlying the Kansas net profits interests in October and November 2009. Lower gas prices caused costs to exceed revenues on properties underlying the Kansas net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the partial recovery of excess costs of $410,957 ($328,766 net to the trust), plus accrued interest of $1,958 ($1,566 net to the trust) in December 2009 and the full recovery of excess costs of $102,518 ($82,014 net to the trust), plus accrued interest of $282 ($226 net to the trust) in January 2010.

There were no excess costs as of December 31, 2010.

Liquidity and Capital Resources

The trust's only cash requirement is the monthly distribution of its income to unitholders, which is funded by the monthly receipt of net profits income after payment of trust administration expenses. The trust is not liable for any production costs or liabilities attributable to the net profits interests. If at any time the trust receives net profits income in excess of the amount due, the trust is not obligated to return such overpayment, but future net profits income payable to the trust will be reduced by the overpayment, plus interest at the prime rate. The trust may borrow funds required to pay trust liabilities if fully repaid prior to further distributions to unitholders.

The trust does not have any transactions, arrangements or other relationships with unconsolidated entities or persons that could materially affect the trust's liquidity or the availability of capital resources.

Greenhouse Gas Emissions and Climate Change Regulation

There is an increased focus by local, national and international regulatory bodies on greenhouse gas (GHG) emissions and climate change. Several states have adopted climate change legislation and regulations, and various other regulatory bodies have announced their intent to regulate GHG emissions or adopt climate change regulations. As these regulations are under development, XTO Energy is unable to predict the total impact of the potential regulations upon the operators of the underlying properties, and it is possible that the operators of the underlying properties could face increases in operating costs in order to comply with climate change or GHG emissions legislation, which costs could reduce net proceeds payable to the trust and trust distributions.

Off-Balance Sheet Arrangements

The trust has no off-balance sheet financing arrangements. The trust has not guaranteed the debt of any other party, nor does the trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations.

Contractual Obligations

As shown below, the trust had no obligations and commitments to make future contractual payments as of December 31, 2010, other than the December distribution payable to unitholders in January 2011, as reflected in the statement of assets, liabilities and trust corpus.

	Payments due by Period				
	Total	**Less than 1 Year**	**1 – 3 Years**	**3 – 5 Years**	**More than 5 Years**
Distribution payable to unitholders	$4,229,120	$4,229,120	$—	$—	$—

Related Party Transactions

The underlying properties from which the net profits interests were carved are currently owned by XTO Energy, which operates approximately 94% of the underlying properties. In computing net proceeds, XTO Energy deducts a monthly overhead charge for reimbursement of administrative expenses on the underlying properties it operates. As of December 31, 2010, the monthly overhead charge, based on the number of operated wells, was approximately $919,000 ($735,200 net to the trust) and is subject to annual adjustment based on an oil and gas industry index.

XTO Energy sells a significant portion of natural gas production from the underlying properties to certain of XTO Energy's wholly owned subsidiaries under contracts in existence when the trust was created, generally at amounts approximating monthly published market prices. For further information regarding natural gas sales from the underlying properties to affiliates of XTO Energy, see Properties, under Item 2, and Note 7 to

Financial Statements under Item 8, Financial Statements and Supplementary Data. Total gas sales from the underlying properties to XTO Energy's wholly owned subsidiaries were $48.5 million for 2010, or 43% of total gas sales, $42.2 million for 2009, or 47% of total gas sales and $103.3 million for 2008, or 47% of total gas sales.

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation. The merger is not expected to have a material effect on trust annual distributable income, financial position or liquidity.

Critical Accounting Policies

The financial statements of the trust are significantly affected by its basis of accounting and estimates related to its oil and gas properties and proved reserves, as summarized below.

Basis of Accounting

The trust's financial statements are prepared on a modified cash basis, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles. This method of accounting is consistent with reporting of taxable income to trust unitholders. The most significant differences between the trust's financial statements and those prepared in accordance with U.S. generally accepted accounting principles are:

- Net profits income is recognized in the month received rather than accrued in the month of production.
- Expenses are recognized when paid rather than when incurred.
- Cash reserves may be established by the trustee for certain contingencies that would not be recorded under U.S. generally accepted accounting principles.

This comprehensive basis of accounting other than U.S. generally accepted accounting principles corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission, as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts. For further information regarding the trust's basis of accounting, see Note 2 to Financial Statements under Item 8, Financial Statements and Supplementary Data.

All amounts included in the trust's financial statements are based on cash amounts received or disbursed, or on the carrying value of the net profits interests, which was derived from the historical cost of the interests at the date of their transfer from XTO Energy, less accumulated amortization to date. Accordingly, there are no fair value estimates included in the financial statements based on either exchange or nonexchange trade values.

Oil and Gas Reserves

The proved oil and gas reserves for the underlying properties are estimated by independent petroleum engineers. The estimated reserves for the underlying properties are then used by XTO Energy to calculate the estimated oil and gas reserves attributable to the net profits interests. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices, may justify revision of such estimates. Because proved reserves are required to be estimated using 12-month average prices, based on the first-day-of-the-month price for each month in the period, estimated reserve quantities can be significantly impacted by changes in product prices. Accordingly, oil and gas quantities ultimately recovered and the timing of production may be substantially different from original estimates.

The standardized measure of discounted future net cash flows and changes in such cash flows, as reported in Note 9 to Financial Statements under Item 8, Financial Statements and Supplementary Data, is prepared using assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission. Such assumptions include using 12-month average oil and gas prices, based on the first-day-of-the-month price for each month in the period for 2010 and 2009, and year end costs for estimated future development and production expenditures. Prior to 2009, standardized measure was calculated using year end oil and gas prices and costs. Discounted future net cash flows are calculated using a 10% rate. Changes in any of these assumptions, including consideration of other factors, could have a significant impact on the standardized measure. Accordingly, the standardized measure does not represent XTO Energy's or the trustee's estimated current market value of proved reserves.

Forward-Looking Statements

Certain information included in this annual report and other materials filed, or to be filed, by the trust with the Securities and Exchange Commission (as well as information included in oral statements or other written statements made or to be made by XTO Energy or the trustee) contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended, relating to the trust, operations of the underlying properties and the oil and gas industry. Such forward-looking statements may concern, among other things, reserve-to-production ratios, future production, development activities, future development plans by area, increased density drilling, maintenance projects, development, production and other costs, oil and gas prices, pricing differentials, proved reserves, future net cash flows, production levels, litigation, regulatory matters and competition. Such forward-looking statements are based on XTO Energy's current plans, expectations, assumptions, projections and estimates and are identified by words such as "expects," "intends," "plans," "projects," "anticipates," "predicts," "believes," "goals," "estimates," "should," "could", and similar words that convey the uncertainty of future events. These statements are not guarantees of future performance and involve certain risks, uncertainties and assumptions that are difficult to predict. Therefore, actual results may differ materially from expectations, estimates or assumptions expressed in, implied in, or forecasted in such forward-looking statements. Some of the risk factors that could cause actual results to differ materially are explained in Item 1A, Risk Factors.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

The only assets of and sources of income to the trust are the net profits interests, which generally entitle the trust to receive a share of the net profits from oil and gas production from the underlying properties. Consequently, the trust is exposed to market risk from fluctuations in oil and gas prices. The trust is a passive entity and, other than the trust's ability to periodically borrow money as necessary to pay expenses, liabilities and obligations of the trust that cannot be paid out of cash held by the trust, the trust is prohibited from engaging in borrowing transactions. The amount of any such borrowings is unlikely to be material to the trust. In addition, the trustee is prohibited by the trust indenture from engaging in any business activity or causing the trust to enter into any investments other than investing cash on hand in specific short-term cash investments. Therefore, the trust cannot hold any derivative financial instruments. As a result of the limited nature of its borrowing and investing activities, the trust is not subject to any material interest rate market risk. Additionally, any gains or losses from any hedging activities conducted by XTO Energy are specifically excluded from the calculation of net proceeds due the trust under the forms of the conveyances. The trust does not engage in transactions in foreign currencies which could expose the trust to any foreign currency related market risk.

Item 8. ***Financial Statements and Supplementary Data***

All financial statement schedules are omitted as they are inapplicable or the required information has been included in the consolidated financial statements or notes thereto.

HUGOTON ROYALTY TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31	
	2010	**2009**
Assets		
Cash and short-term investments	**$ 4,229,120**	$ 4,284,800
Net profits interests in oil and gas properties – net (Notes 1 and 2)	**124,993,766**	139,877,580
	$129,222,886	$144,162,380
Liabilities and Trust Corpus		
Distribution payable to unitholders	**$ 4,229,120**	$ 4,284,800
Trust corpus (40,000,000 units of beneficial interest authorized and outstanding)	**124,993,766**	139,877,580
	$129,222,886	$144,162,380

See accompanying notes to financial statements.

HUGOTON ROYALTY TRUST

STATEMENTS OF DISTRIBUTABLE INCOME

	Year Ended December 31		
	2010	**2009**	**2008**
Net profits income	**$62,883,206**	$30,180,880	$117,268,069
Interest income	**1,108**	465	91,203
Total income	**62,884,314**	30,181,345	117,359,272
Administration expense	**856,314**	875,105	864,872
Distributable income	**$62,028,000**	$29,306,240	$116,494,400
Distributable income per unit (40,000,000 units)	**$ 1.550700**	$ 0.732656	$ 2.912360

See accompanying notes to financial statements.

HUGOTON ROYALTY TRUST

STATEMENTS OF CHANGES IN TRUST CORPUS

	Year Ended December 31		
	2010	**2009**	**2008**
Trust corpus, beginning of year	**$139,877,580**	$146,722,015	$ 155,820,033
Amortization of net profits interests	**(14,883,814)**	(6,844,435)	(9,098,018)
Distributable income	**62,028,000**	29,306,240	116,494,400
Distributions declared	**(62,028,000)**	(29,306,240)	(116,494,400)
Trust corpus, end of year	**$124,993,766**	$139,877,580	$ 146,722,015

See accompanying notes to financial statements.

Hugoton Royalty Trust

NOTES TO FINANCIAL STATEMENTS

1. Trust Organization and Provisions

Hugoton Royalty Trust was created on December 1, 1998 by XTO Energy Inc. (formerly known as ''Cross Timbers Oil Company''). Effective on that date, XTO Energy conveyed 80% net profits interests in certain predominantly gas-producing working interest properties in Kansas, Oklahoma and Wyoming to the trust under separate conveyances for each of the three states. In exchange for the conveyances of the net profits interests to the trust, XTO Energy received 40 million units of beneficial interest in the trust. The trust's initial public offering was in April 1999. The majority of the underlying working interest properties are currently owned and operated by XTO Energy (Note 7).

Bank of America, N.A. is the trustee for the trust. In 2007 the Bank of America private wealth management group officially became known as ''U.S. Trust, Bank of America Private Wealth Management.'' The legal entity that serves as the trustee of the trust did not change, and references in this Annual Report to U.S. Trust, Bank of America Private Wealth Management shall describe the legal entity Bank of America, N.A. The trust indenture provides, among other provisions, that:

- the trust cannot engage in any business activity or acquire any assets other than the net profits interests and specific short-term cash investments;
- the trust may dispose of all or part of the net profits interests if approved by 80% of the unitholders, or upon trust termination. Otherwise, the trust may sell up to 1% of the value of the net profits interests in any calendar year, pursuant to notice from XTO Energy of its desire to sell the related underlying properties. Any sale must be for cash with the proceeds promptly distributed to the unitholders;
- the trustee may establish a cash reserve for payment of any liability that is contingent or not currently payable;
- the trustee may borrow funds to pay trust liabilities if repaid in full prior to further distributions to unitholders;
- the trustee will make monthly cash distributions to unitholders (Note 3); and
- the trust will terminate upon the first occurrence of:
  - — disposition of all net profits interests pursuant to terms of the trust indenture,
  - — gross proceeds from the underlying properties falling below $1 million per year for two successive years, or
  - — a vote of 80% of the unitholders to terminate the trust in accordance with provisions of the trust indenture.

2. Basis of Accounting

The financial statements of the trust are prepared on the following basis and are not intended to present financial position and results of operations in conformity with U.S. generally accepted accounting principles:

- Net profits income is recorded in the month received by the trustee (Note 3).
- Trust expenses are recorded based on liabilities paid and cash reserves established by the trustee for liabilities and contingencies.
- Distributions to unitholders are recorded when declared by the trustee (Note 3).

The most significant differences between the trust's financial statements and those prepared in accordance with U.S. generally accepted accounting principles are:

- Net profits income is recognized in the month received rather than accrued in the month of production.

- Expenses are recognized when paid rather than when incurred.
- Cash reserves may be established by the trustee for contingencies that would not be recorded under U.S. generally accepted accounting principles.

This comprehensive basis of accounting corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission, as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with U.S. generally accepted accounting principles, directing such entities to accrue or defer revenues and expenses in a period other than when such revenues were received or expenses were paid. Because the trust's financial statements are prepared on the modified cash basis, as described above, most accounting pronouncements are not applicable to the trust's financial statements.

The initial carrying value of the net profits interests of $247,066,951 was XTO Energy's historical net book value of the interests on December 1, 1998, the date of the transfer to the trust. Amortization of the net profits interests is calculated on a unit-of-production basis and charged directly to trust corpus. Accumulated amortization was $122,073,185 as of December 31, 2010 and $107,189,371 as of December 31, 2009.

3. Distributions to Unitholders

The trustee determines the amount to be distributed to unitholders each month by totaling net profits income, interest income and other cash receipts, and subtracting liabilities paid and adjustments in cash reserves established by the trustee. The resulting amount is distributed to unitholders of record within ten business days after the monthly record date, which is the last business day of the month.

Net profits income received by the trustee consists of net proceeds received in the prior month by XTO Energy from the underlying properties, multiplied by 80%. Net proceeds are the gross proceeds received from the sale of production, less costs. Costs generally include applicable taxes, transportation, legal and marketing charges, production expense, development and drilling costs, and overhead (Note 7).

XTO Energy, as owner of the underlying properties, computes net profits income separately for each of the three conveyances (one for each of the states of Kansas, Oklahoma and Wyoming). If costs exceed revenues for any conveyance, such excess costs must be recovered, with accrued interest, from future net proceeds of that conveyance and cannot reduce net profits income from the other conveyances (Note 4).

4. Excess Costs

Costs exceeded revenues by $513,475 ($410,780 net to the trust) on properties underlying the Kansas net profits interests in October and November 2009. Lower gas prices caused costs to exceed revenues on properties underlying the Kansas net profits interests. However, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the partial recovery of excess costs of $410,957 ($328,766 net to the trust), plus accrued interest of $1,958 ($1,566 net to the trust) in December 2009 and the full recovery of excess costs of $102,518 ($82,014 net to the trust), plus accrued interest of $282 ($226 net to the trust) in January 2010.

Costs exceeded revenues by $970,780 ($776,624 net to the trust) on properties underlying the Wyoming net profits interests in November 2008. Lower gas prices caused costs to exceed revenues on properties underlying the Wyoming net profits interest, however, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the full recovery of excess costs, plus accrued interest of $3,192 ($2,554 net to the trust) in December 2008.

Costs exceeded revenues by $853,468 ($682,774 net to the trust) on properties underlying the Wyoming net profits interests in November and December 2007. Lower gas prices caused costs to exceed revenues on properties underlying the Wyoming net profits interest, however, these excess costs did not reduce net proceeds from the remaining conveyances. XTO Energy advised the trustee that increased gas prices led to the full recovery of excess costs, plus accrued interest of $10,090 ($8,072 net to the trust) in February 2008.

There were no excess costs as of December 31, 2010.

5. Development Costs

The following summarizes actual development costs, budgeted development costs deducted in the calculation of net profits income, and the cumulative actual costs compared to the amount deducted:

	Year Ended December 31		
	2010	**2009**	**2008**
Cumulative actual costs under (over) the amount deducted – beginning of period	**$ 909,477**	$ (7,314,084)	$ (675,754)
Actual costs	**(8,969,173)**	(12,776,439)	(52,638,330)
Budgeted costs deducted	**7,250,000**	21,000,000	46,000,000
Cumulative actual costs (over) under the amount deducted – end of period	**$ (809,696)**	$ 909,477	$ (7,314,084)

The monthly development cost deduction was $3.75 million from the January 2008 distribution through the August 2008 distribution. Due to higher than anticipated costs as a result of the timing of expenditures, the monthly development cost deduction was increased to $4.0 million beginning with the September 2008 distribution and was maintained at that level through the March 2009 distribution. As a result of decreased development activity and revisions to the 2009 development budget, the development cost deduction was decreased to $2.0 million beginning with the April 2009 distribution, to $1.0 million beginning with the June 2009 distribution and to $500,000 beginning with the September 2009 distribution and was maintained at that level through the July 2010 distribution. As a result of increased development activity, the development cost deduction was increased to $600,000 beginning with the August 2010 distribution and to $850,000 beginning with the October 2010 distribution and was maintained at that level through the remainder of 2010. For further information on 2011 budgeted development costs, see Properties, under Item 2. The monthly deduction is based on the current level of development expenditures, budgeted future development costs and the cumulative actual costs under (over) previous deductions. XTO Energy has advised the trustee that this monthly deduction will continue to be evaluated and revised as necessary.

6. Federal Income Taxes

Tax counsel has advised the trust that, under current tax laws, the trust will be classified as a grantor trust for federal income tax purposes and, therefore, is not subject to taxation at the trust level. However, the opinion of tax counsel is not binding on the Internal Revenue Service. For federal income tax purposes, unitholders of a grantor trust are considered to own the trust's income and principal as though no trust were in existence. The income of the trust is deemed to be received or accrued by the unitholders at the time such income is received or accrued by the trust, rather than when distributed by the trust.

The trust is a widely held fixed investment trust (''WHFIT'') classified as a non-mortgage widely held fixed investment trust (''NMWHFIT'') for federal income tax purposes. The trustee is the representative of the trust that will provide tax information in accordance with the applicable U.S. Treasury Regulations governing the information reporting requirements of the trust as a WHFIT or a NMWHFIT.

7. XTO Energy Inc.

XTO Energy operates approximately 94% of the underlying properties. In computing net proceeds, XTO Energy deducts an overhead charge for reimbursement of administrative expenses on the underlying properties it operates. As of December 31, 2010, the overhead charge was approximately $919,000 ($735,200 net to the trust) per month and is subject to annual adjustment based on an oil and gas industry index as defined in the trust agreement.

XTO Energy sells a significant portion of natural gas production from the underlying properties to certain of XTO Energy's wholly owned subsidiaries under contracts in existence when the trust was created, generally at amounts approximating monthly published market prices. Most of the production from the Hugoton area is sold under a contract to Timberland Gathering & Processing Company, Inc. ("TGPC") based on the index price. Much of the gas production in Major County, Oklahoma is sold to Ringwood Gathering Company ("RGC"), which retains approximately $0.31 per Mcf as a compression and gathering fee. TGPC and RGC sell gas to Cross Timbers Energy Services, Inc. ("CTES"), which markets gas to third parties. XTO Energy sells directly to CTES most gas production not sold directly to TGPC or RGC. For additional information on these arrangements, see Item 2, Properties.

Total gas sales from the underlying properties to XTO Energy's wholly owned subsidiaries were $48.5 million for 2010, or 43% of total gas sales, $42.2 million for 2009, or 47% of total gas sales, $103.3 million for 2008, or 47% of total gas sales.

On June 25, 2010, XTO Energy became a wholly owned subsidiary of Exxon Mobil Corporation. The merger is not expected to have a material effect on trust annual distributable income, financial position or liquidity.

8. Contingencies

Litigation

An amended petition for a class action lawsuit, *Beer, et al. v. XTO Energy Inc.*, was filed in January 2006 in the District Court of Texas County, Oklahoma by certain royalty owners of natural gas wells in Oklahoma and Kansas. The plaintiffs allege that XTO Energy has not properly accounted to the plaintiffs for the royalties to which they are entitled and seek an accounting regarding the natural gas and other products produced from their wells and the prices paid for the natural gas and other products produced, and for payment of the monies allegedly owed since June 2002, with a certain limited number of plaintiffs claiming monies owed for additional time. XTO Energy removed the case to federal district court in Oklahoma City. A hearing on the class certification was conducted in October 2008. At the class certification hearing, the plaintiffs sought to certify a class of royalty owners whose wells were connected to a processing plant owned by a subsidiary of XTO Energy in the Hugoton Field, with two sub-classes consisting of owners in Oklahoma and Kansas. In March 2009, the court granted the motion to certify the class. The plaintiffs filed a motion for summary judgment for only the two named plaintiffs. The court granted the motion in the amount of $12,779. A motion for summary judgment related to the remainder of the class was denied. Trial was scheduled for April 2010; however, the court vacated the trial date. At a hearing in April 2010, the court ruled that the class representatives were no longer proper representatives and stated that it was considering whether to dismiss class counsel or decertify the class in whole or in part. In a subsequent ruling in April 2010, the court decertified the class. In April 2010, new counsel and representative parties, Fankhouser and Goddard, filed a motion to intervene and prosecute the *Beer* class. This motion was granted on July 13, 2010. The new plaintiffs and counsel filed an amended complaint asserting new causes of action for breach of fiduciary duties and unjust enrichment. Following an additional class discovery period, a class certification hearing was held on September 27, 2010. On December 16, 2010, the court certified the class. XTO Energy has informed the trustee that it believes that it has strong defenses to this lawsuit and intends to vigorously defend its position. However, if XTO Energy ultimately makes any settlement payments or receives a judgment against it, the trust will bear its 80% share of such settlement or judgment related to production from the underlying properties. Additionally, if a judgment or settlement increases the amount of future payments to royalty owners, the trust would bear its proportionate share of the increased payments through reduced net proceeds. XTO Energy has informed the trustee that, although the amount of any reduction in net proceeds is not presently determinable, in its management's opinion, the amount is not currently expected to be material to the trust's annual distributable income, financial position or liquidity. It could, however, result in costs exceeding revenues on the properties underlying the Oklahoma and Kansas net profit interests for one or more monthly distributions, depending on the size of the judgment or settlement, if any, and the net proceeds being paid at that time.

In September 2008, a class action lawsuit was filed against XTO Energy styled *Wallace B. Roderick Revocable Living Trust, et al. v. XTO Energy Inc.* in the District Court of Kearny County, Kansas. XTO Energy removed the case to federal court in Wichita, Kansas. The plaintiffs allege that XTO Energy has improperly taken post-production costs from royalties paid to the plaintiffs from wells located in Kansas, Oklahoma and Colorado. The plaintiffs also seek to represent all royalty owners in these three states as a class. The plaintiffs' claims overlap the claims made by the plaintiffs in the *Beer/Fankhouser* case as to certain properties. XTO Energy has answered, denying all claims, and has filed motions to dismiss a portion of the claims. In January 2010, the federal court granted XTO Energy's motion for summary judgment concerning prior settled class actions that overlap plaintiffs' proposed class action. The court also granted XTO Energy's motion to dismiss those portions of plaintiffs' class that are currently being prosecuted in the *Beer/Fankhouser* class action discussed above. The *Roderick* plaintiffs have also filed a motion to include the former *Beer/Fankhouser* class into this litigation. The court denied the motion. The plaintiffs have filed a motion to certify the class. XTO Energy has informed the trustee that it believes that XTO Energy has strong defenses to this lawsuit and intends to vigorously defend its position. However, if XTO Energy ultimately makes any settlement payments or receives a judgment against it, the trust will bear its 80% share of such settlement or judgment related to production from the underlying properties. Additionally, if the judgment or settlement increases the amount of future payments to royalty owners, the trust would bear its proportionate share of the increased payments through reduced net proceeds. XTO Energy has informed the trustee that, although the amount of any reduction in net proceeds is not presently determinable, in its management's opinion, the amount is not currently expected to be material to the trust's annual distributable income, financial position or liquidity. It could, however, result in costs exceeding revenues on the properties underlying the Oklahoma and Kansas net profit interests for one or more monthly distributions, depending on the size of the judgment or settlement, if any, and the net proceeds being paid at that time.

Certain of the underlying properties are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. XTO Energy has advised the trustee that it does not believe that the ultimate resolution of these claims will have a material effect on trust annual distributable income, financial position or liquidity.

Other

Several states have enacted legislation to require state income tax withholding from nonresident recipients of oil and gas proceeds. After consultation with its state tax counsel, XTO Energy has advised the trustee that it believes the trust is not subject to these withholding requirements. However, regulations could be issued by the various states which could change this conclusion. Should the trust be required to withhold state taxes, distributions to the unitholders would be reduced by the required amount, subject to the unitholder's right to file a state tax return to claim any refund due.

9. Supplemental Oil and Gas Reserve Information (Unaudited)

Oil and Natural Gas Reserves

Proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared with the cost of a new well. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of 12-month average prices for oil and gas, based on the first-day-of-the-month price for each month in the period for 2010 and 2009, and year end costs for estimated future development and production expenditures to produce the proved reserves. Prior to 2009, standardized measure was calculated using year end oil and gas prices and costs. Future net cash flows are discounted at an annual rate of 10%. No provision is included for federal income taxes since future net cash flows are not subject to taxation at the trust level.

Estimated costs to plug and abandon wells on the underlying working interest properties at the end of their productive lives have not been deducted from cash flows since this is not a legal obligation of the trust. These costs are the legal obligation of XTO Energy as the owner of the underlying working interests and will only be deducted from net proceeds payable to the trust if net proceeds from the related conveyance exceed such costs when paid, subject to excess cost carryforward provisions (Notes 3 and 4).

The standardized measure does not represent management's estimate of our future cash flows or the value of proved oil and gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, prices used to determine the standardized measure are influenced by supply and demand as affected by recent economic conditions as well as other factors and may not be the most representative in estimating future revenues or reserve data.

The average realized gas prices used to determine the standardized measure were $4.45 per Mcf in 2010, $3.28 per Mcf in 2009, $4.47 per Mcf in 2008 and $6.72 per Mcf in 2007. Oil prices used to determine the standardized measure were based on average realized oil prices of $75.91 per Bbl in 2010, $57.17 per Bbl in 2009, $42.13 per Bbl in 2008 and $95.73 per Bbl in 2007. In 2010 and 2009, we used average oil and gas prices, based on the first-day-of-the-month price for each month in the period. For periods prior to 2009, we used year end oil and gas prices.

Hugoton Royalty Trust

NOTES TO FINANCIAL STATEMENTS

Proved Reserves

(in thousands)	Underlying Properties Gas (Mcf)	Underlying Properties Oil (Bbls)	Net Profits Interests Gas (Mcf)	Net Profits Interests Oil (Bbls)
Balance, December 31, 2007	405,473	3,645	224,948	2,110
Extensions, additions and discoveries	10,493	120	3,432	39
Revisions of prior estimates	(21,485)	(114)	(36,762)	(297)
Production – sales volumes	(28,176)	(342)	(13,135)	(170)
Balance, December 31, 2008	366,305	3,309	178,483	1,682
Extensions, additions and discoveries	5,447	354	2,369	154
Revisions of prior estimates	(21,865)	(398)	(55,473)	(621)
Production – sales volumes	(26,642)	(260)	(8,326)	(91)
Balance, December 31, 2009	323,245	3,005	117,053	1,124
Extensions, additions and discoveries	11	—	5	—
Revisions of prior estimates	15,813	123	33,833	353
Production – sales volumes	(24,075)	(267)	(12,455)	(141)
Balance, December 31, 2010	314,994	2,861	138,436	1,336

Extensions, additions and discoveries in 2008, 2009 and 2010 are primarily related to delineation of additional proved undeveloped reserves in the Anadarko Basin. Revisions of prior estimates of the proved gas reserves for the underlying properties in each year are primarily because of changes in the gas and oil prices. Higher upward and downward revisions for the net profits interests as compared with the underlying properties in each year were caused by changes in oil and gas prices and estimated future production and development costs which resulted in an increase or decrease in gas reserves allocated to the trust.

Proved Developed Reserves

(in thousands)	Underlying Properties Gas (Mcf)	Underlying Properties Oil (Bbls)	Net Profits Interests Gas (Mcf)	Net Profits Interests Oil (Bbls)
December 31, 2007	352,732	3,234	198,187	1,896
December 31, 2008	325,891	2,960	164,080	1,554
December 31, 2009	283,864	2,560	110,050	1,056
December 31, 2010	276,089	2,513	126,349	1,218

Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)	December 31 2010	2009	2008
Underlying Properties			
Future cash inflows	$1,619,640	$1,231,607	$1,786,971
Future costs:			
Production	721,736	640,707	711,349
Development	68,201	70,479	66,456
Future net cash flows	829,703	520,421	1,009,166
10% discount factor	405,114	245,392	494,416
Standardized measure	$ 424,589	$ 275,029	$ 514,750
Net Profits Interests			
Future cash inflows	$ 722,885	$ 453,108	$ 875,222
Future production taxes	59,122	36,771	67,889
Future net cash flows	663,763	416,337	807,333
10% discount factor	324,092	196,314	395,533
Standardized measure	$ 339,671	$ 220,023	$ 411,800

Changes in Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

(in thousands)	2010	2009	2008
Underlying Properties			
Standardized measure, January 1	$ 275,029	$ 514,750	$ 975,928
Revisions:			
Prices and costs	207,026	(215,257)	(365,784)
Quantity estimates	(1,121)	(24,458)	(9,546)
Accretion of discount	23,818	44,852	84,305
Future development costs	(796)	(16,352)	(28,435)
Production rates and other	(781)	(1,090)	(542)
Net revisions	228,146	(212,305)	(320,002)
Extensions, additions and discoveries	18	10,310	5,409
Production	(85,854)	(58,726)	(192,585)
Development costs	7,250	21,000	46,000
Net change	149,560	(239,721)	(461,178)
Standardized measure, December 31	$ 424,589	$ 275,029	$ 514,750
Net Profits Interests			
Standardized measure, January 1	$ 220,023	$ 411,800	$ 780,742
Extensions, additions and discoveries	14	8,248	4,327
Accretion of discount	19,054	35,882	67,444
Revisions of prior estimates, changes in price and other	163,463	(205,726)	(323,445)
Net profits income	(62,883)	(30,181)	(117,268)
Standardized measure, December 31	$ 339,671	$ 220,023	$ 411,800

10. Quarterly Financial Data (Unaudited)

The following is a summary of net profits income, distributable income and distributable income per unit by quarter for 2010 and 2009:

	Net Profits Income	Distributable Income	Distributable Income per Unit
2010			
First Quarter	**$16,899,222**	**$16,565,120**	**$0.414128**
Second Quarter	**18,974,132**	**18,732,920**	**0.468323**
Third Quarter	**14,695,353**	**14,527,360**	**0.363184**
Fourth Quarter	**12,314,499**	**12,202,600**	**0.305065**
	$62,883,206	**$62,028,000**	**$1.550700**
2009			
First Quarter	$ 5,777,425	$ 5,465,360	$0.136634
Second Quarter	4,537,110	4,263,720	0.106593
Third Quarter	8,533,583	8,371,600	0.209290
Fourth Quarter	11,332,762	11,205,560	0.280139
	$30,180,880	$29,306,240	$0.732656

Report of Independent Registered Public Accounting Firm

Bank of America, N.A., as Trustee for the Hugoton Royalty Trust:

We have audited the accompanying statements of assets, liabilities, and trust corpus of the Hugoton Royalty Trust as of December 31, 2010 and 2009, and the related statements of distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2010. We also have audited Hugoton Royalty Trust's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The trustee of Hugoton Royalty Trust is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Trustee's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the trust's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by the trustee, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As described in note 2 to the financial statements, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

The trust's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the modified cash basis of accounting. The trust's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the modified cash basis of accounting, and that receipts and expenditures of the trust are being made only in accordance with authorizations of the trustee; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the trust's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities, and trust corpus of Hugoton Royalty Trust as of December 31, 2010 and 2009, and its distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2010, in conformity with the modified cash basis of accounting described in note 2. Also in our opinion, Hugoton Royalty Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

KPMG LLP
Fort Worth, Texas
February 24, 2011

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

There have been no changes in accountants and no disagreements with the trust's independent registered public accountants on any matter of accounting principles or practices or financial statement disclosures during the two years ended December 31, 2010.

Item 9A. *Controls and Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

The trustee conducted an evaluation of the trust's disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, the trustee has concluded that the trust's disclosure controls and procedures were effective as of the end of the period covered by this annual report. In its evaluation of disclosure controls and procedures, the trustee has relied, to the extent considered reasonable, on information provided by XTO Energy.

Trustee's Report on Internal Control Over Financial Reporting

The trustee, Bank of America, N.A., also known as U.S. Trust, Bank of America Private Wealth Management, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934, as amended. The trustee conducted an evaluation of the effectiveness of the trust's internal control over financial reporting based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the trustee's evaluation under the framework in *Internal Control — Integrated Framework*, the trustee concluded that the trust's internal control over financial reporting was effective as of December 31, 2010. The effectiveness of the trust's internal control over financial reporting as of December 31, 2010 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report under Item 8, Financial Statements and Supplementary Data.

There were no changes in the trust's internal control over financial reporting during the quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, the trust's internal control over financial reporting.

Item 9B. *Other Information*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

The trust has no directors, executive officers or audit committee. The trustee is a corporate trustee which may be removed, with or without cause, by the affirmative vote of the holders of a majority of all the units then outstanding.

Section 16(a) of the Securities Exchange Act of 1934 requires that directors, officers, and beneficial owners of more than 10% of the registrant's equity securities file initial reports of beneficial ownership and reports of changes in beneficial ownership with the Securities and Exchange Commission and the New York Stock Exchange. To the trustee's knowledge, based solely on the information furnished to the trustee, the trustee is unaware of any person that failed to file on a timely basis reports required by Section 16(a) filing requirements with respect to the trust units of beneficial interest during and for the year ended December 31, 2010.

Because the trust has no employees, it does not have a code of ethics. Employees of the trustee, U.S. Trust, Bank of America Private Wealth Management, must comply with the bank's code of ethics, a copy of which will be provided to unitholders, without charge, upon request by appointment at Bank of America Plaza, 17th Floor, 901 Main Street, Dallas, Texas 75202.

Item 11. *Executive Compensation*

The trustee received the following annual compensation from 2008 through 2010 as specified in the trust indenture:

Name and Principal Position	Year	Other Annual Compensation[1]
U.S. Trust, Bank of America	2010	$52,563
Private Wealth Management, Trustee	2009	48,126
	2008	45,602

(1) Under the trust indenture, the trustee is entitled to an annual administrative fee, paid in equal monthly installments. Such fee can be adjusted annually based on an oil and gas industry index. Upon termination of the trust, the trustee is entitled to a termination fee of $15,000.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters*

The trust has no equity compensation plans.

(a) *Security Ownership of Certain Beneficial Owners.* The trustee is not aware of any person who beneficially owns more than 5% of the outstanding units.

(b) *Security Ownership of Management.* The trust has no directors or executive officers. As of January 19, 2011, Bank of America, N.A. owned, in various fiduciary capacities, 344,677 units, with a shared right to vote 197,672 of these units and no right to vote 147,005 of these units. Bank of America, N.A. disclaims any beneficial interests in these units. The number of units reflected in this paragraph includes units held by all branches of Bank of America, N.A.

(c) *Changes in Control.* The trustee knows of no arrangements which may subsequently result in a change in control of the trust.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

In computing net profits income paid to the trust for the net profits interests, XTO Energy deducts an overhead charge for reimbursement of administrative expenses of operating the underlying properties. This charge at December 31, 2010 was approximately $919,000 per month, or $11,028,000 annually (net to the trust of $735,200 per month or $8,822,400 annually), and is subject to annual adjustment based on an oil and gas industry index as defined in the trust agreement.

XTO Energy sells a significant portion of natural gas production from the underlying properties to certain of its wholly owned subsidiaries under contracts in existence when the trust was created, generally at amounts approximating monthly published prices. For further information, see Item 2, Properties.

See Item 11, Executive Compensation, for the remuneration received by the trustee from 2008 through 2010 and Item 12(b), Security Ownership of Management, for information concerning units owned by the trustee in various fiduciary capacities.

As noted in Item 10, Directors, Executive Officers and Corporate Governance, the trust has no directors, executive officers or audit committee. The trustee is a corporate trustee which may be removed, with or without cause, by the affirmative vote of the holders of a majority of all the units then outstanding.

Item 14. ***Principal Accountant Fees and Services***

Fees for services performed by KPMG LLP for the years ended December 31, 2010 and 2009 are:

	2010	2009
Audit fees	$79,900	$77,500
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
	$79,900	$77,500

As referenced in Item 10, Directors, Executive Officers and Corporate Governance, above, the trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to KPMG LLP.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) The following documents are filed as a part of this report:

1. *Financial Statements (included in Item 8 of this report)*

   Independent Registered Public Accounting Firm Report

   Statements of Assets, Liabilities and Trust Corpus at December 31, 2010 and 2009

   Statements of Distributable Income for the years ended December 31, 2010, 2009 and 2008

   Statements of Changes in Trust Corpus for the years ended December 31, 2010, 2009 and 2008

   Notes to Financial Statements

2. *Financial Statement Schedules*

Financial statement schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. *Exhibits*

(4) (a) Hugoton Royalty Trust Indenture by and between NationsBank, N.A. (now Bank of America, N.A.), as trustee, and Cross Timbers Oil Company (predecessor of XTO Energy) heretofore filed as Exhibit 4.1 to the trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on December 4, 1998, is incorporated herein by reference.

(b) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% – Kansas) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A. (now Bank of America, N.A.), as trustee, dated December 1, 1998, heretofore filed as Exhibit 10.1.1 to the trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

(c) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% – Oklahoma) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A. (now Bank of America, N.A.), as trustee, dated December 1, 1998, heretofore filed as Exhibit 10.1.2 to the trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

(d) Net Overriding Royalty Conveyance (Hugoton Royalty Trust, 80% – Wyoming) as amended and restated from Cross Timbers Oil Company (predecessor of XTO Energy) to NationsBank, N.A. (now Bank of America, N.A.), as trustee, dated December 1, 1998, heretofore filed as Exhibit 10.1.3 to the trust's Registration Statement No. 333-68441 on Form S-1 filed with the Securities and Exchange Commission on March 16, 1999, is incorporated herein by reference.

(31) Rule 13a-14(a)/15d-14(a) Certification

(32) Section 1350 Certification

(99.1) Miller and Lents, Ltd. Report

Copies of the above Exhibits are available to any unitholder, at the actual cost of reproduction, upon written request to the trustee, U.S. Trust, Bank of America Private Wealth Management, P.O. Box 830650, Dallas, Texas 75283-0650.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned thereunto duly authorized.

HUGOTON ROYALTY TRUST
By BANK OF AMERICA, N.A., TRUSTEE

By /s/ NANCY G. WILLIS
Nancy G. Willis
Vice President

EXXON MOBIL CORPORATION

Date: February 24, 2011

By /s/ PATRICK T. MULVA
Patrick T. Mulva
Vice President and Controller

(The trust has no directors or executive officers.)

HUGOTON ROYALTY TRUST

901 Main Street, 17th Floor
P.O. Box 830650
Dallas, Texas 75283-0650
(877) 228-5083
U.S. Trust, Bank of America
Private Wealth Management, Trustee

A copy of the Hugoton Royalty Trust Form 10-K has been provided with this Annual Report. Additional copies of this Annual Report and Form 10-K will be provided to unitholders without charge upon request. Copies of exhibits to the Form 10-K may be obtained upon request or from the trust's web site at www.hugotontrust.com.

WEBSITE

www.hugotontrust.com

AUDITORS

KPMG LLP
Fort Worth, Texas

LEGAL COUNSEL

Thompson & Knight L.L.P.
Dallas, Texas

TAX COUNSEL

Winstead PC
Houston, Texas

TRANSFER AGENT AND REGISTRAR

American Stock Transfer and Trust Company
www.amstock.com

CERTIFICATION

The Trustee's certification, required by Section 302 of the Sarbanes-Oxley Act of 2002, has been filed as Exhibit 31 of the Trust's Form 10-K, for the fiscal year ended December 31, 2010.

HUGOTON
ROYALTY TRUST

901 Main Street, 17th Floor
P.O. Box 830650
Dallas, Texas 75283-0650
(877) 228-5083
U.S. Trust, Bank of America
Private Wealth Management, Trustee