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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2003

OR

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

Commission file number: 001-11335

Dominion Resources Black Warrior Trust

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

75-6461716
(I.R.S. employer
identification number)

**Trust Division
Royalty Trust Group
Bank of America, N.A.
901 Main Street
17th Floor
Dallas, Texas 75202**

(Address of principal executive offices; Zip Code)

Registrant's telephone number, including area code:
(214) 209-2400

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

<u>Title of Each Class</u>	<u>Name of Each Exchange on Which Registered</u>
Units of Beneficial Interest	New York Stock Exchange, Inc.

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: None

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the 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 a check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes No

The aggregate market value of the registrant's units of beneficial interest outstanding (based on the closing sale price on the New York Stock Exchange) held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter was approximately \$219,000,000.

At March 1, 2004, there were 7,850,000 units of beneficial interest outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

TABLE OF CONTENTS

	<u>Page</u>
PART I.....	1
Item 1. Business.....	1
GLOSSARY.....	1
DESCRIPTION OF THE TRUST	4
Creation and Organization of the Trust	4
Assets of the Trust	4
Duties and Limited Powers of the Trustee and the Delaware Trustee.....	4
Resignation of Trustees	5
Transfer of Royalty Interests.....	5
Liabilities of the Trust.....	6
Liabilities of the Trustee and the Delaware Trustee	6
Termination and Liquidation of the Trust	6
Arbitration and Actions by Unitholders	7
DESCRIPTION OF UNITS	8
Distributions and Income Computations	9
Conditional Right of Repurchase	10
Possible Divestiture of Units.....	11
Periodic Reports	11
Voting Rights of Unitholders	12
Liability of Unitholders	13
Transfer Agent	13
Website/SEC Filings	13
FEDERAL INCOME TAX CONSIDERATIONS	13
Summary of Certain Federal Income Tax Consequences	14
ERISA CONSIDERATIONS	20
STATE TAX CONSIDERATIONS	20
Alabama Income Tax	20
Alabama Business Privilege Tax	21
Alabama Severance Taxes	21
Other Alabama Taxes	21
REGULATION AND PRICES	22
Regulation of Natural Gas	22
Environmental Regulation	22
Competition, Markets and Prices	23
Item 2. Properties	24
THE ROYALTY INTERESTS	24
The Underlying Properties	24
The Royalty Interests	26
Reserve Estimate	27
Natural Gas Sales Prices and Production	29
Gas Purchase Agreement	29
Operation of Properties	30
Sale and Abandonment of Underlying Properties	30
Dominion Resources’s Assurances	31
Title to Properties	31
Item 3. Legal Proceedings	32
Item 4. Submission of Matters to a Vote of Security Holders	32
PART II	32
Item 5. Market for Registrant’s Common Equity and Related Stockholder Matters	32

	<u>Page</u>
Item 6. Selected Financial Data	32
Item 7. Trustee’s Discussion and Analysis of Financial Condition and Results of Operations.....	32
Critical Accounting Policies and Estimates.....	35
Liquidity and Capital Resources.....	36
Off-Balance Sheet Arrangements	37
Tabular Disclosure of Contractual Obligations	37
Forward-Looking Statements	37
Item 7A. Quantitative and Qualitative Disclosures About Market Risk.....	37
Item 8. Financial Statements and Supplementary Data	38
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	48
Item 9A. Controls and Procedures	48
PART III	49
Item 10. Directors and Executive Officers of the Registrant.....	49
Item 11. Executive Compensation	49
Item 12. Security Ownership of Certain Beneficial Owners and Management	50
Item 13. Certain Relationships and Related Transactions.....	50
Administrative Services Agreement.....	50
Dominion Resources’s Conditional Right of Repurchase	50
Potential Conflicts of Interest	50
Item 14. Principal Accounting Fees and Services	51
PART IV	51
Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K	51
1. Financial Statements	51
2. Financial Statement Schedules.....	51
3. Exhibits	52
(b) Reports on Form 8-K	53
SIGNATURES	54

PART I

Item 1. *Business.*

GLOSSARY

The following is a glossary of certain defined terms used in this Annual Report on Form 10-K.

“Administrative Services Agreement” means the Administrative Services Agreement dated as of June 28, 1994, between Dominion Resources and the Trust, a copy of which is filed as an exhibit to this Form 10-K.

“Bcf” means billion cubic feet of natural gas.

“Btu” means British Thermal Unit, the common unit of gross heating value measurement for natural gas.

“Code” means the Internal Revenue Code of 1986, as amended.

“Company” means Dominion Black Warrior Basin, Inc., an Alabama corporation and a wholly-owned indirect subsidiary of Dominion Resources.

“Company Interests” means the Company’s interest in the Underlying Properties, as of June 1, 1994, not burdened by the Royalty Interests.

“Company Interests Owner” means the Company while it owns all or part of the Company Interests and any other person or persons who acquire all or any part of the Company Interests or any operating rights therein other than a royalty, overriding royalty, production payment or net profits interest.

“ConocoPhillips” means ConocoPhillips Corporation, successor to The River Gas Corporation.

“Contract Price” means the price at which, pursuant to the Gas Purchase Agreement, El Paso Merchant Energy—Gas, L.P., as successor to Sonat Marketing, is obligated to purchase the Subject Gas at the central delivery points in the gathering system for the Underlying Properties. Pursuant to a Gas Purchase Agreement amendment, effective January 1, 2001 through December 31, 2001, the Contract Price for each month equaled (a) for quantities of Gas equal to or less than 25% of the Monthly Base Quantity, \$3.97 per MMBtu, (b) for quantities of Gas over and above 25% of the Monthly Base Quantity up to 75% of the Monthly Base Quantity, the sum of the Index Price and Premium, which Price could not be less than a floor of \$3.00 per MMBtu and could not be greater than a ceiling of \$5.30 per MMBtu, (c) for quantities of Gas over and above 75% of the Monthly Base Quantity up to the Monthly Base Quantity, the sum of the Index Price and Premium, and (d) for quantities of Gas in excess of the Monthly Base Quantity, the sum of the Index Price and \$0.02 per MMBtu. Pursuant to a Gas Purchase Agreement amendment, effective January 1, 2002 through December 31, 2002, the Contract Price for each month equaled (a) for quantities of Gas up to and including the applicable Monthly Fixed Price Quantity, \$3.70 per MMBtu, and (b) for quantities of Gas over and above the Monthly Fixed Price Quantity up to the Monthly Base Quantity, the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to that same Gas Purchase Agreement amendment, commencing January 1, 2002, the Contract Price for quantities of Gas over and above the Monthly Base Quantity equaled the sum of (i) the Index Price and (ii) \$.02 per MMBtu, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to the same Gas Purchase Agreement amendment, commencing January 1, 2003, the price for quantities up to and including the Monthly Base Quantity shall be the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to the July 1, 2002 Gas Purchase Agreement amendment, effective January 1, 2003, the price payable by El Paso for each MMBtu of Gas produced up to and including the applicable monthly specified base quantity during each month shall be divided into two categories, a Fixed Price Quantity and an Index Price Quantity (as defined therein). Until December 31, 2003, the price payable by

El Paso for each MMBtu of Gas produced up to and including the applicable monthly Fixed Price Quantity shall be \$3.68 per MMBtu. The price payable by El Paso for each MMBtu of gas produced in excess of the applicable monthly Fixed Price Quantity and up to and including the applicable monthly Index Price Quantity shall be the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Commencing January 1, 2004, the pricing formula for the Index Price Quantity described in the immediately preceding sentence shall apply to the entire Monthly Base Quantity. Also effective January 1, 2004, the price payable by El Paso for gas production in excess of the specified Monthly Base Quantity each month shall be the sum of the Index Price and \$.02 per MMBtu, multiplied by 0.9826, the wet/dry conversion factor. Prices are subject to negotiation and arbitration at the request of either party if they are unable to reach agreement. Effective January 31, 2004, the Gas Purchase Agreement was terminated. Effective February 1, 2004, Gas will be sold on a month to month basis to various purchasers until such time as a long-term contract can be secured.

“Conveyance” means the Overriding Royalty Conveyance dated effective as of June 1, 1994, from the Company to the Trust, as amended by instrument dated as of November 20, 1994, copies of which are filed as exhibits to this Form 10-K.

“Delaware Trustee” means Mellon Bank (DE) National Association.

“Dominion Resources” means Dominion Resources, Inc., a Virginia corporation.

“El Paso” means El Paso Merchant Energy—Gas, L.P., successor to Sonat Marketing Company.

“Existing Wells” means the wells producing on the Underlying Properties as of June 1, 1994.

“Gas” means natural gas produced and sold from the Underlying Properties.

“Gas Purchase Agreement” means the Gas Purchase Agreement dated as of May 3, 1994, between the Company and El Paso, as successor to Sonat Marketing, as amended by instruments effective as of April 1, 1996, May 16, 1996, April 9, 1998, July 1, 1999, July 1, 2000, July 1, 2001 and July 1, 2002.

“Gross Proceeds” means the aggregate amounts received by the Company Interests Owner attributable to the Company Interests from the sale of Subject Gas at the central delivery points in the gathering system for the Underlying Properties.

“Gross Wells” means the total whole number of gas wells without regard to ownership interest.

“Index Price” means the price published by *Inside FERC Gas Market Report* in its first issue of the month which posts prices for the beginning of such month for “Prices of Spot Gas Delivered to Pipelines—Southern Natural Gas Co.—Louisiana—Index,” for such month.

“Mcf” means thousand cubic feet of natural gas. Natural gas volumes are stated herein at the legal pressure base of 14.65 or 14.73 pounds per square inch absolute, as the case may be, at 60 degrees Fahrenheit.

“MMcf” means million cubic feet of natural gas. As used herein, 1 MMcf is assumed to have a Btu content of 1004 MMBtu.

“MMBtu” means million Btu. As used herein, 996 MMBtu is deemed to be the Btu content of 1 MMcf.

“Monthly Base Quantity” means the volumes of natural gas designated as such in the Gas Purchase Agreement.

“Monthly Fixed Price Quantity” means the volumes of natural gas designated as such from time to time in the Gas Purchase Agreement.

“Net revenue interest” means working interest or mineral interest less any applicable royalties, overriding royalties or similar burdens on production prior to the Royalty Interests.

“Net wells” and “net acres” are calculated by multiplying gross wells or gross acres by the ownership interest in such wells or acres.

“Prospectus” means the prospectus dated June 21, 1994, as supplemented by the final prospectus supplement dated June 1, 1995, relating to the offer and sale of the Units, and forming a part of Dominion Resources’s Registration Statement on Form S-3 (No. 33-53513).

“Ralph E. Davis & Associates” means Ralph E. Davis & Associates, independent petroleum engineers.

“Reserve Estimate” means the estimated net proved reserves, estimated future net revenues and the discounted estimated future net revenues attributable to the Royalty Interests as of January 1, 2004, prepared by Ralph E. Davis & Associates.

“Royalty Interests” means the overriding royalty interests conveyed to the Trust pursuant to the Conveyance entitling the holder thereof to 65 percent of the Gross Proceeds derived from the Company Interests.

“Section 29 tax credit” means the tax credits for federal income tax purposes pursuant to Section 29 of the Code to an owner of coal seam gas production, which tax credits are generated upon the sale of such production.

“Sonat Marketing” means Sonat Marketing Company, a Delaware Corporation.

“Subject Gas” means Gas attributable to the Company Interests.

“Trust” means Dominion Resources Black Warrior Trust, a Delaware business trust formed pursuant to the Trust Agreement.

“Trust Agreement” means the Trust Agreement dated as of May 31, 1994, among the Company, as grantor, Dominion Resources, the Delaware Trustee and the Trustee, as amended by instrument dated as of June 27, 1994, copies of which are filed as exhibits to this Form 10-K.

“Trustee” means Bank of America, N.A., as successor to NationsBank of Texas, N.A.

“Working interest” generally refers to the lessee’s interest in an oil, gas or mineral lease which entitles the owner to receive a specified percentage of oil and gas production, but requires the owner of such working interest to bear such specified percentage of the costs to explore for, develop, produce and market such oil and gas.

“Underlying Properties” means the natural gas properties in which the Company has an interest located in the Black Warrior Basin, Tuscaloosa County, Alabama insofar as such properties include the Pottsville Formation.

“Units” means the 7,850,000 units of beneficial interest issued by, and evidencing the entire beneficial interest in, the Trust.

DESCRIPTION OF THE TRUST

Dominion Resources Black Warrior Trust is a Delaware business trust formed under the Delaware Business Trust Act, Title 12, Chapter 38 of the Delaware Code, Section 3801 et seq. (the "Delaware Code"). The following information is subject to the detailed provisions of the Trust Agreement and the Conveyance, copies of which are filed as exhibits to this Form 10-K. The provisions governing the Trust are complex and extensive, and no attempt has been made below to describe or reference all of such provisions. The following is a general description of the basic framework of the Trust and the material provisions of the Trust Agreement.

Creation and Organization of the Trust

The Trust was initially created by the filing of its Certificate of Trust with the Delaware Secretary of State on May 31, 1994. In accordance with the Trust Agreement, the Company contributed \$1,000 as the initial corpus of the Trust. On June 28, 1994, the Royalty Interests were conveyed to the Trust by the Company pursuant to the Conveyance, in consideration for the issuance to the Company of all 7,850,000 of the authorized Units in the Trust. The Company transferred all the Units to its parent, Dominion Energy, Inc., a Virginia corporation ("Dominion Energy"), which in turn transferred all the Units to its parent, Dominion Resources. Dominion Resources sold an aggregate of 6,904,000 Units to the public through various underwriters (the "Underwriters") in June and August 1994 in the initial public offering of the Units (the "Initial Public Offering") and sold the remaining 946,000 Units to the public through certain of the Underwriters in June 1995 pursuant to Post-Effective Amendment No. 1 to the Form S-3 Registration Statement relating to the Units (the "Secondary Public Offering" and, collectively with the Initial Public Offering, the "Public Offerings").

Assets of the Trust

The only assets of the Trust, other than cash and temporary investments being held for the payment of expenses and liabilities and for distribution to Unitholders, are the Royalty Interests. The Royalty Interests consist of overriding royalty interests burdening the Company's interest in the Underlying Properties. The Royalty Interests generally entitle the Trust to receive 65 percent of the Company's Gross Proceeds. The Royalty Interests are non-operating interests and bear only expenses related to property, production and related taxes (including severance taxes). See "Properties—The Royalty Interests."

The Company has advised the Trustee that all the production attributable to the Underlying Properties is from the Pottsville coal formation and is coal seam gas that entitled the owners of such production to tax credits pursuant to Section 29 of the Code upon the production and sale of such gas before January 1, 2003, provided certain requirements were satisfied. See "—Federal Income Tax Considerations."

Duties and Limited Powers of the Trustee and the Delaware Trustee

Under the Trust Agreement, the Trustee has all powers to collect the payments attributable to the Royalty Interests and to pay all expenses, liabilities and obligations of the Trust. The Trustee has the discretion to establish a cash reserve for the payment of any liability that is contingent or uncertain in amount or that otherwise is not currently due and payable. The Trustee is entitled to cause the Trust to borrow money from any source, including from the entity serving as Trustee (provided that the entity serving as Trustee shall not be obligated to lend to the Trust), to pay expenses, liabilities and obligations that cannot be paid out of cash held by the Trust. To secure payment of any such indebtedness (including any indebtedness to the Trustee), the Trustee is authorized to (i) mortgage and otherwise encumber the entire Trust estate or any portion thereof; (ii) carve out and convey production payments; (iii) include all terms, powers, remedies, covenants and provisions it deems necessary or advisable, including confession of judgment and the power of sale with or without judicial proceedings; and (iv) provide for the exercise of those and other remedies available to a secured lender

in the event of a default on such loan. The terms of such indebtedness and security interest, if funds were loaned by the Trustee, must be similar to the terms that the Trustee would grant to a similarly-situated commercial customer with whom it did not have a fiduciary relationship, and the Trustee shall be entitled to enforce its rights with respect to any such indebtedness and security interest as if it were not then serving as Trustee.

The Delaware Trustee has only such powers as are set forth in the Trust Agreement or are required by law and is not empowered to take part in the management of the Trust.

The Royalty Interests are passive in nature and neither the Trustee nor the Delaware Trustee has any control over or any responsibility relating to the operation of the Underlying Properties. The Company does not have any contractual commitment to the Trust to develop further the Underlying Properties or to maintain its ownership interest in any of the Underlying Properties. The Company may sell the Company Interests subject to and burdened by the Royalty Interests and, absent certain conditions having been met, with the continuing benefit of Dominion Resources's assurances and the Gas Purchase Agreement. For a description of the Underlying Properties, the Royalty Interests and other information relating to such properties, see "Properties—The Royalty Interests."

The Trust Agreement authorizes the Trustee to take such action as in its judgment is necessary, desirable or advisable to best achieve the purposes of the Trust. The Trustee is empowered by the Trust Agreement to employ consultants and agents (including the Company, Dominion Energy and Dominion Resources) and to make payments of all fees for services or expenses out of the assets of the Trust. The Trustee is authorized to agree to modifications of the terms of the Conveyance and to settle disputes with respect thereto, so long as such modifications or settlements do not result in the treatment of the Trust as an association taxable as a corporation for federal income tax purposes and such modifications or settlements do not alter the nature of the Royalty Interests as a right to receive a share of production or the proceeds of production from the Underlying Properties, which, with respect to the Trust, are free of any operating rights, expenses or obligations. The Trust Agreement provides that cash being held by the Trustee as a reserve for liabilities or for distribution at the next distribution date will be placed in demand deposit accounts, U.S. government obligations, repurchase agreements secured by such obligations or certificates of deposit, but the Trustee is otherwise prohibited from acquiring any asset other than the Royalty Interests and cash proceeds therefrom or engaging in any business or investment activity of any kind whatsoever. The Trustee may deposit funds awaiting distribution in an account with the Trustee provided the interest rate paid equals the interest rate paid by the Trustee on similar deposits.

The Trust has no employees. Administrative functions are performed by the Trustee.

Resignation of Trustees

The Trustee and the Delaware Trustee may resign at any time upon 60 days' prior written notice or be removed, with or without cause, by a vote of not less than a majority of the outstanding Units, provided in each case that a successor trustee has been appointed and has accepted its appointment. Any successor must be a bank or trust company meeting certain requirements, including having capital, surplus and undivided profits of at least \$100,000,000, in the case of the Trustee, and \$20,000,000, in the case of the Delaware Trustee.

Transfer of Royalty Interests

Prior to the termination of the Trust, the Trustee is not authorized to sell or otherwise dispose of all or any part of the Royalty Interests. The Trustee is authorized and directed to sell and convey the Royalty Interests without Unitholder approval upon termination of the Trust. No Unitholder approval for sales or dispositions upon termination is required even though they may constitute a disposition of all or substantially all the assets of the Trust. Any sales upon termination may be made to Dominion Resources or its affiliates. See "—Termination and Liquidation of the Trust."

Liabilities of the Trust

Because of the passive nature of the Trust assets and the restrictions on the activities of the Trustee, the only liabilities the Trust has incurred are those for routine administrative expenses, such as trusteeship fees and accounting, engineering, legal and other professional fees and the administrative services fee paid to Dominion Resources. If a court were to hold that the Trust is taxable as a corporation, then the Trust would incur substantial federal income tax liabilities. See also “—State Tax Considerations—Alabama Franchise Tax.”

Liabilities of the Trustee and the Delaware Trustee

Each of the Trustee and the Delaware Trustee may act in its discretion and is personally or individually liable only for fraud or acts or omissions in bad faith or that constitute gross negligence (and for taxes, fees and other charges on, based on or measured by any fees, commissions or compensation received pursuant to the Trust Agreement) and will not be otherwise liable for any act or omission of any agent or employee unless such Trustee has acted in bad faith or with gross negligence in the selection and retention of such agent or employee. Each of the Trustee and the Delaware Trustee (and their respective agents) is indemnified by Dominion Resources and from the Trust assets for certain environmental liabilities, and for any other liability, expense, claim, damage or other loss incurred in performing its duties, unless resulting from gross negligence, fraud or bad faith (each of the Trustee and the Delaware Trustee is indemnified from the Trust assets against its own negligence that does not constitute gross negligence), and will have a first lien upon the assets of the Trust as security for such indemnification and for reimbursements and compensation to which it is entitled; provided that the Trustee and the Delaware Trustee are generally required to first be indemnified from the Trust assets before seeking indemnification from Dominion Resources. Dominion Resources also has agreed to indemnify the Trustee and the Delaware Trustee against liabilities under certain securities laws. Neither the Trustee nor the Delaware Trustee is entitled to indemnification from Unitholders (except in connection with lost or destroyed Unit certificates). Insofar as indemnification for liabilities arising under the Securities Act of 1933, as amended (the “Securities Act”), is permitted to the Trustee pursuant to the foregoing provisions, the Trustee has been informed that in the opinion of the Securities and Exchange Commission (the “Commission”), such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable.

Termination and Liquidation of the Trust

The Trust will terminate upon the occurrence of: (i) an affirmative vote of the holders of not less than 66 percent of the outstanding Units to terminate the Trust; (ii) such time as the ratio of the cash amounts received by the Trust attributable to the Royalty Interests in any calendar quarter to administrative costs of the Trust for such calendar quarter is less than 1.2 to 1.0 for two consecutive calendar quarters; or (iii) March 1 of any year if it is determined, based on a reserve report as of December 31 of the prior year prepared by a firm of independent petroleum engineers mutually selected by the Trustee and the Company, that the net present value (discounted at 10 percent) of (a) estimated future net revenues from proved reserves attributable to the Royalty Interests plus (b) the amount of all remaining Section 29 tax credits attributable to the Royalty Interests, is equal to or less than \$5 million (as applicable, the “Termination Date”). As discussed in “Description of Units—Federal Income Tax Considerations,” coal seam gas produced and sold after December 31, 2002, will no longer generate a Section 29 tax credit unless the Section 29 tax credit is extended or reinstated by Congress. Upon such occurrence causing the Trust to terminate, the remaining assets of the Trust will be sold, the net proceeds of the sale will be distributed to Unitholders and the Trust will be wound up and a certificate of cancellation filed.

Upon the termination of the Trust, the Trustee will use its best efforts to sell any remaining Royalty Interests then owned by the Trust for cash pursuant to the procedures described in the Trust Agreement. The Trustee will retain a nationally recognized investment banking firm (the “Advisor”) on behalf of the Trust who will assist the Trustee in selling the remaining Royalty Interests. The

Company has the right, but not the obligation, within 60 days following the Termination Date, to make a cash offer to purchase all of the remaining Royalty Interests then held by the Trust. In the event such an offer is made by the Company, the Trustee will decide, based on the recommendation of the Advisor, to either (i) accept such offer (in which case no sale to the Company will be made unless a fairness opinion is given by the Advisor that the purchase price is fair to Unitholders) or (ii) defer action on the offer for approximately 60 days and seek to locate other buyers for the remaining Royalty Interests. If the Trustee defers action on the Company's offer, the offer will be deemed withdrawn and the Trustee will then use its best efforts, assisted by the Advisor, to locate other buyers for the Royalty Interests. At the end of the 120-day period following the Termination Date, the Trustee is required to notify the Company of the highest of any other offers acceptable to the Trustee (which must be an all-cash offer) received during such period (such price, net of any commissions or other fees payable by the Trust, the "Highest Acceptable Offer"). The Company then has the right (whether or not it made an initial offer), but not the obligation, to purchase all remaining Royalty Interests for a cash purchase price computed as follows: (i) if the Highest Acceptable Offer is more than 105 percent of the Company's original offer (or if the Company did not make an initial offer), the purchase price will be 105 percent of the Highest Acceptable Offer, or (ii) if the Highest Acceptable Offer is equal to or less than 105 percent of the Company's original offer, the purchase price will be equal to the Highest Acceptable Offer. If no other acceptable offers are received for all remaining Royalty Interests, the Trustee may request the Company to submit another offer for consideration by the Trustee and may accept or reject such offer.

If a sale of the Royalty Interests is made or a definitive contract for sale of the Royalty Interests is entered into within a 150-day period following the Termination Date, the buyer of the Royalty Interests, and not the Trust or Unitholders, will be entitled to all proceeds of production attributable to the Royalty Interests following the Termination Date.

In the event that the Company does not purchase the Royalty Interests, the Trustee may accept any offer for all or any part of the Royalty Interests as it deems to be in the best interests of the Trust and Unitholders and may continue, for up to one calendar year after the Termination Date, to attempt to locate a buyer or buyers of the remaining Royalty Interests in order to sell such interests in an orderly fashion. If the Royalty Interests have not been sold or a definitive agreement for sale has not been entered into by the end of such calendar year, the Trustee is required to sell the remaining Royalty Interests at a public auction, which sale may be to the Company or any of its affiliates.

The Company's purchase rights, as described above, may be exercised by the Company and each of its successors in interest and assigns. The Company's purchase rights are fully assignable by the Company to any person or entity. The costs of liquidation, including the fees and expenses of the Advisor and the Trustee's liquidation fee, will be paid by the Trust.

The Trust may terminate without Unitholder approval. Unitholders are not entitled to any rights of appraisal or similar rights in connection with the termination of the Trust.

Arbitration and Actions by Unitholders

Pursuant to the Trust Agreement, any dispute, controversy or claim that may arise between or among Dominion Resources or the Company, on the one hand, and the Trustee, the Delaware Trustee or the Trust, on the other hand, in connection with or otherwise relating to the Trust Agreement or the Conveyance or the application, implementation, validity or breach thereof or any provision thereof, shall be settled by final and binding arbitration in Dallas, Texas in accordance with the Rules of Practice and Procedure for the arbitration of commercial disputes of Judicial Arbitration & Mediation Services, Inc. (or any successor thereto) then in effect. The Administrative Services Agreement also includes a provision that will require Dominion Resources and the Trustee and the Trust to submit any dispute regarding such contract to alternative dispute resolution before litigating such matter.

The Trust Agreement requires under certain circumstances that the Trustee and the Trust pursue any claims against Dominion Resources and the Company with respect to any breach by Dominion

Resources and the Company of the terms of the Conveyance or the Trust Agreement (and requires that any such claims be brought in arbitration), without the joinder of any Unitholder. The Trust Agreement does not provide for any procedure allowing Unitholders to bring an action on their own behalf to enforce the rights of the Trust under the Conveyance and, except in the case of the failure of the Trustee to enforce certain performance obligations of Dominion Resources to the Trust, does not provide for any procedure allowing Unitholders to direct the Trustee to bring an action on behalf of the Trust to enforce the Trust's rights under the Conveyance. Each Unitholder has a statutory right, however, under Section 3816 of the Delaware Code to bring a derivative action in the Delaware Court of Chancery on behalf of the Trust to enforce the rights of the Trust if the Trustee has refused to bring the action or if an effort to cause the Trustee to bring the action is not likely to succeed. The procedures for the arbitration of disputes enumerated in the Trust Agreement neither bar nor restrict the statutory right of any Unitholder under Section 3816 of the Delaware Code to bring a derivative action.

Pursuant to Section 3816 of the Delaware Code, a plaintiff in a derivative action must be a beneficial owner at the time such action is brought and (i) at the time of the transaction subject to such complaint or (ii) the Unitholder's status as a beneficial owner must have devolved upon it by operation of law or pursuant to the terms of the governing instrument of the Trust from a person or entity who was a beneficial owner at the time of the transaction giving rise to the complaint. If a derivative action is successful, in whole or in part, or if anything is received by the Trust as a result of a judgment, compromise or settlement of any such action, the Delaware Chancery Court may award the plaintiff reasonable expenses, including reasonable attorney's fees. If any award is so received by the plaintiff, the Delaware Chancery Court will make such award of the plaintiff's expenses payable out of those proceeds and direct the plaintiff to remit to the Trust the remainder thereof. If the proceeds are insufficient to reimburse the plaintiff's reasonable expenses in bringing the derivative action, the Delaware Chancery Court may direct that any such award of the plaintiff's expenses or a portion thereof be paid by the Trust. The rights of Unitholders to bring a derivative action on behalf of the Trust provided pursuant to the Trust Agreement and Section 3816 of the Delaware Code are substantially similar to the derivative rights afforded stockholders under Section 327 of Chapter 8 of the Delaware General Corporation Law and applicable Delaware case law.

In the event that any Unitholder was successful in bringing a derivative action on behalf of the Trust to enforce rights on behalf of the Trust against Dominion Resources or the Company, then such Unitholder could, on behalf of the Trust, pursue such rights against Dominion Resources or the Company, as the case may be, in the Delaware Chancery Court. The Trust Agreement does not require, and expressly provides that it shall not be construed to require, arbitration of a claim or dispute solely between the Trustee and the Delaware Trustee or of any claim or dispute brought by any person or entity, including, without limitation, any Unitholder (whether in its own right or through a derivative action in the right of the Trust) who is not a party to the Trust Agreement.

The right of a Unitholder to bring a derivative action on behalf of the Trust with respect to Dominion Resources's obligation to cure certain deficiencies under the Trust Agreement is subject to the restriction that such right may only be exercised by Unitholders owning of record not less than 25 percent of the Units then outstanding (treated as a single class) and then only absent action by the Trustee to enforce any such obligation within 10 days following receipt by the Trustee of a written request served upon the Trustee by such Unitholders to take such action. In such an event, Unitholders owning of record not less than 25 percent of the Units then outstanding may, acting as a single class and on behalf of the Trust, seek to enforce such obligations. See "Properties—The Royalty Interests—Dominion Resources's Assurances."

DESCRIPTION OF UNITS

Each Unit represents an equal undivided share of beneficial interest in the Trust and is evidenced by a transferable certificate issued by the Trustee. Each Unit entitles its holder to the same rights as the

holder of any other Unit, and the Trust has no other authorized or outstanding class of equity security. At March 1, 2004, there were 7,850,000 Units outstanding. The Trust may not issue additional Units.

Distributions and Income Computations

The Trustee determines for each calendar quarter the amount of cash available for distribution to Unitholders. Such amount (the "Quarterly Distribution Amount") is equal to the excess, if any, of the cash received by the Trust attributable to production from the Royalty Interests during such calendar quarter, provided that such cash is received by the Trust on or before the last business day prior to the 45th day following the end of such calendar quarter, plus the amount of interest expected by the Trustee to be earned on such cash proceeds during the period between the date of receipt by the Trust of such cash proceeds and the date of payment to the Unitholders of such Quarterly Distribution Amount, plus all other cash receipts of the Trust during such calendar quarter (to the extent not distributed or held for future distribution as a Special Distribution Amount (as defined herein) or included in the previous Quarterly Distribution Amount) (which might include sales proceeds not sufficient in amount to qualify for a special distribution, as described in the next paragraph, and interest), over the liabilities of the Trust paid during such calendar quarter and not taken into account in determining a prior Quarterly Distribution Amount, subject to adjustments for changes made by the Trustee during such calendar quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. An amount that is not included in the Quarterly Distribution Amount for a calendar quarter because such amount is received by the Trust after the last business day prior to the 45th day following the end of such calendar quarter shall be included in the Quarterly Distribution Amount for the next calendar quarter. The Quarterly Distribution Amount for each calendar quarter will be payable to Unitholders of record on the 60th day following the end of such calendar quarter, unless such day is not a business day in which case the record date will be the next business day thereafter. The Trustee will distribute the Quarterly Distribution Amount for each calendar quarter on or prior to 70 days after the end of such calendar quarter to each person who was a Unitholder of record on the record date for such calendar quarter.

The Royalty Interests will be sold in whole or in part upon termination of the Trust. Any proceeds from sales of the Royalty Interests, plus any interest expected by the Trustee to be earned thereon, less liabilities and expenses of the Trust and amounts used for cash reserves, will be distributed to Unitholders of record on the record date established for such distribution. A special distribution will be made of undistributed cash proceeds and other amounts received by the Trust aggregating in excess of \$10,000,000, plus the amount of interest expected by the Trustee to be earned on such cash proceeds during the period between the date of receipt by the Trust of such cash proceeds and the date of payment to the Unitholders of such special distribution (a "Special Distribution Amount"). The record date for distribution of a Special Distribution Amount will be the 15th day following receipt of amounts aggregating a Special Distribution Amount by the Trust (unless such day is not a business day in which case the record date will be the next business day thereafter) unless such day is within 10 days prior to the record date for a Quarterly Distribution Amount in which case the record date will be the date as is established for the next Quarterly Distribution Amount. Distributions to Unitholders will be no later than 15 days after the Special Distribution Amount record date.

Gross income attributable to cash being distributed in most cases will be reported for federal income tax purposes by the Unitholder who receives such distributions assuming that such Unitholder is the owner of record on the applicable record date. In certain circumstances, however, a Unitholder will not receive the cash giving rise to such income. For example, the Trustee maintains a cash reserve, and is authorized to borrow money under certain conditions, in order to pay or provide for the payment of Trust liabilities. Income associated with the cash used to increase that reserve or to repay that loan must be reported by the Unitholder, even though that cash is not distributed to him. Likewise, if a portion of a cash distribution is attributable to a reduction in the cash reserve maintained by the Trustee, such cash is treated as a reduction to the Unitholder's basis in his Units and is not treated as

taxable income to such Unitholder (assuming such Unitholder's basis exceeds the amount of the cash distribution).

Conditional Right of Repurchase

Dominion Resources (and any of its successors and affiliates) has the right to repurchase all (but not less than all) outstanding Units at any time at which 15 percent or less of the outstanding Units are owned by persons or entities other than Dominion Resources and its affiliates. Subject to the following sentence, any such repurchase would be at a price equal to the greater of (i) the highest price at which Dominion Resources or any of its affiliates acquired Units during the 90 days immediately preceding the date (the "Determination Date") that is 3 New York Stock Exchange ("NYSE") trading days prior to the date on which notice of such exercise is delivered to the Unitholders and (ii) the average closing price of Units on the NYSE for the 30 trading days immediately preceding the Determination Date. If Dominion Resources or any of its affiliates acquires Units (other than an acquisition from Dominion Resources or any affiliate) during the period that is 3 NYSE trading days after the Determination Date at a price per Unit greater than that at which an acquisition was made during the 90-day period referred to in clause (i) of the preceding sentence, then for purposes of clause (i) of the preceding sentence the highest price used therein will be such greater price. Any such repurchase would be conducted in accordance with applicable federal and state securities laws.

In the event that Dominion Resources elects to purchase all Units, Dominion Resources and the Trustee will, prior to the date fixed for purchase, give all Unitholders of record not less than 15 days' nor more than 60 days' written notice specifying the time and place of such repurchase, calling upon each such Unitholder to surrender to Dominion Resources on the repurchase date at the place designated in such notice its certificate or certificates representing the number of Units specified in such notice of repurchase. On or after the repurchase date, each holder of Units to be repurchased must present and surrender its certificates for such Units to Dominion Resources at the place designated in such notice and thereupon the purchase price of such Units will be paid to or on the order of the person or entity whose name appears on such certificate or certificates as the owner thereof. In no event may fewer than all of the outstanding Units represented by the certificates be repurchased (except for any Units held by Dominion Resources and any of its affiliates).

If Dominion Resources and the Trustee give a notice of repurchase and if, on or before the date fixed for repurchase, the funds necessary for such repurchase are set aside by Dominion Resources, separate and apart from its other funds in trust for the pro rata benefit of the holders of the Units so noticed for repurchase, then, notwithstanding that any certificate for such Units has not been surrendered, at the close of business on the repurchase date the holders of such Units shall cease to be Unitholders and shall have no interest in or claims against Dominion Resources, the Company, the Trust, the Delaware Trustee or the Trustee by virtue thereof and shall have no voting or other rights with respect to such Units, except the right to receive the purchase price payable upon such repurchase, without interest thereon and without any other distributions for record dates after the date of notice of repurchase, upon surrender (and endorsement, if required by Dominion Resources) of their certificates, and the Units evidenced thereby shall no longer be held of record in the names of such Unitholders. Subject to applicable escheat laws, any monies so set aside by Dominion Resources and unclaimed at the end of 2 years from the repurchase date shall revert to the general funds of Dominion Resources. After such reversion, the holders of such Units so noticed for repurchase could look only to the general funds of Dominion Resources for the payment of the purchase price. Any interest accrued on funds so deposited would be paid to Dominion Resources from time to time as requested by Dominion Resources.

If Dominion Resources exercises and consummates its right of repurchase, then, at its option, it may cause the Trust to be terminated by providing written notice thereof to the Trustee and the Delaware Trustee. Within 30 days following written notice of Dominion Resources's decision to terminate the Trust, the Trustee must cause any remaining Royalty Interests (and, subject to the rights of Unitholders with respect to the receipt of distributions for which a record date has been determined,

all proceeds of production attributable to the Royalty Interests) and any other assets of the Trust to be conveyed to Dominion Resources or its assignee (subject to the right of such trustees to create reasonable reserves in connection with the liquidation of the Trust).

Possible Divestiture of Units

The Trust Agreement imposes no restrictions based on nationality or other status of Unitholders. The Trust Agreement provides, however, that in the event of certain judicial or administrative proceedings seeking the cancellation or forfeiture of any property in which the Trust has an interest, or asserting the invalidity of, or otherwise challenging any portion of the Royalty Interests because of the nationality, citizenship or any other status of any one or more Unitholders, the Trustee will give written notice thereof to each Unitholder whose nationality, citizenship or other status is an issue in the proceeding, which notice will constitute a demand that such Unitholder dispose of his Units within 30 days. If any Unitholder fails to dispose of his Units in accordance with such notice, the Trustee will cancel all outstanding certificates issued in the name of such Unitholder, transfer all Units held by such Unitholder to the Trustee and sell such Units (including by private sale). The proceeds of such sale (net of sales expenses), pending delivery of certificates representing the Units, will be held by the Trustee in a non-interest bearing account for the benefit of the Unitholder and paid to the Unitholder upon surrender of such certificates. Cash distributions payable to such Unitholder will also be held in a non-interest bearing account pending disposition by the Unitholder of the Units or cancellation of certificates representing the Units by the Trustee, subject to a maximum retention period of 2 years or such shorter period as shall be permitted by applicable laws.

Periodic Reports

The Trustee causes a reserve report to be prepared for the Trust (by a firm of independent petroleum engineers mutually selected by the Trustee and the Company) each year showing estimated proved natural gas reserves and other reserve information attributable to the Royalty Interests as of December 31 of such year. Such reserve reports show estimated future net revenues and the net present value (discounted at 10 percent) of the estimated future net revenues (using the year-end market or Contract Price as of December 31 as appropriate) from proved reserves attributable to the Royalty Interests. The costs of the reserve reports are paid by the Trust and constitute an administrative expense. The Trustee also provides to Dominion Resources and the Company, within 15 days after the end of each calendar quarter, a written itemized report showing all administrative costs of the Trust paid during such quarter.

Within 75 days following the end of each of the first three calendar quarters of each calendar year, the Trustee mails to each person or entity who was a Unitholder of record (i) on the record date for each such calendar quarter and (ii) on a Special Distribution Amount record date occurring during such quarter, if any, a report showing in reasonable detail the assets, liabilities, receipts and disbursements of the Trust for such calendar quarter. Within 120 days following the end of each fiscal year, the Trustee mails to Unitholders of record as of a date to be selected by the Trustee an annual report containing audited financial statements, including reserve information relating to the Trust and the Royalty Interests.

The Trustee files such returns for federal income tax purposes as it is advised are required to comply with applicable law. The Trustee mails to each person or entity who was a Unitholder of record (i) on the record date for each such calendar quarter and (ii) on a Special Distribution Amount record date occurring during such quarter, if any, a report that shows in reasonable detail information to permit each Unitholder to make all calculations reasonably necessary for tax purposes. The Trustee treats all income, credits and deductions recognized during each calendar quarter during the term of the Trust as having been recognized by holders of record on the quarterly record date established for the distribution unless otherwise advised by counsel. Available year-end tax information permitting each Unitholder to make all calculations reasonably necessary for tax purposes is distributed by the Trustee to Unitholders no later than March 15 of the following year.

Each Unitholder and his duly authorized agents and attorneys have the right during reasonable business hours, and upon reasonable prior notice, to examine and inspect records of the Trust and the Trustee and the Delaware Trustee.

Voting Rights of Unitholders

While Unitholders have certain voting rights as provided in the Trust Agreement, such rights differ from and are more limited than those of stockholders of a corporation for profit. For example, there is no requirement for annual meetings of Unitholders or for annual or other periodic reelection of the Trustee.

Meetings of Unitholders may be called by the Trustee or by Unitholders owning not less than 10 percent of the outstanding Units. In addition, the Delaware Trustee may call such a meeting but only for the purpose of appointing a successor to it upon its resignation. All meetings of Unitholders will be held in Dallas, Texas. Written notice of every such meeting setting forth the time and place of the meeting and the matters proposed to be acted upon will be given not more than 60 days nor less than 20 days before such meeting is to be held to all of the Unitholders of record at the close of business on a record date selected by the Trustee, which record date will not be more than 60 days before the date of such meeting. The presence in person or by proxy of Unitholders representing a majority of the outstanding Units is necessary to constitute a quorum. Each Unitholder is entitled to one vote for each Unit owned by such Unitholder. The Trustee will call such meetings to consider amendments, waivers, consents and other changes relating to the Conveyance, if requested in writing by the Company or Dominion Resources. No matter other than that stated in the notice of the Unitholder meeting will be voted on and no action by the Unitholders may be taken without a meeting.

Generally, amendments to the Trust Agreement require approval of a majority of the outstanding Units (except that amendments of required voting percentages requires approval of at least 80 percent of the outstanding Units), but no provision of the Trust Agreement may be amended that would (i) increase the power of the Trustee or the Delaware Trustee to engage in business or investment activities or (ii) alter the rights of the Unitholders as among themselves. Without the written consent of Dominion Resources and the approval of not less than 66 $\frac{2}{3}$ percent of the outstanding Units, no provision of the Trust Agreement may be amended with respect to (a) the sale or disposition of all or any part of the Trust estate, including the Royalty Interests, except as specifically provided in the Trust Agreement; (b) termination of the Trust and the disposition of Trust assets upon liquidation of the Trust; or (c) the Company's right of first refusal with respect to the purchase of any remaining Royalty Interests upon termination of the Trust. Without the written consent of Dominion Resources and the approval of a majority of the outstanding Units, no amendment may be made to the Trust Agreement that would alter Dominion Resources's conditional right to repurchase all outstanding Units at any time at which 15 percent or less of the outstanding Units is owned by persons or entities other than Dominion Resources or its affiliates. Additionally, any amendment that increases the obligations, duties or liabilities of or affects the rights of the Trustee or the Delaware Trustee must be consented to by such entity. The Trustee, the Delaware Trustee, Dominion Resources and the Company may, without approval of Unitholders, from time to time supplement or amend the Trust Agreement in order to cure any ambiguity or to correct or supplement any defective or inconsistent provisions, provided such supplement or amendment is not adverse to the interests of Unitholders. In addition, (i) Dominion Resources may direct the Trustee to change the name of the Trust without approval of Unitholders and (ii) in the event that a business purpose of the Trust is found or deemed to exist by any taxing or other authority on which finding any taxation authority might rely, the Trustee is authorized to amend or delete and, subject to the receipt of an opinion of counsel reasonably satisfactory to the Trustee, the Trustee, the Delaware Trustee, Dominion Resources and the Company will amend or delete any provision of the Trust Agreement or take such other action as may be necessary to eliminate such business purpose, without approval of Unitholders. Removal of the Trustee and the Delaware Trustee, approval of amendments, waivers, consents and other changes relating to the Conveyance and the approval of the merger or consolidation of the Trust into one or more entities require approval of a

majority of the outstanding Units. Except as set forth under “Description of the Trust — Termination and Liquidation of the Trust,” all other actions may be approved by a majority vote of the Units represented at a meeting at which a quorum is present or represented.

Liability of Unitholders

Consistent with Delaware law, the Trust Agreement provides that Unitholders will have the same limitation on liability as is accorded under Delaware law to stockholders of a corporation for profit. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation.

Transfer Agent

Mellon Investor Services, L.L.C. (as successor to Chemical Shareholder Services Group, Inc.) serves as transfer agent and registrar for the Units.

Website/SEC Filings

The Trust maintains an Internet Website at www.dom-dominionblackwarriortrust.com, and will provide website access to its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to such reports as soon as reasonably practicable after such material is filed with or furnished to the SEC.

FEDERAL INCOME TAX CONSIDERATIONS

The Tax Consequences to a Unitholder of the Ownership and Sale of Units will Depend in Part on the Unitholder’s Tax Circumstances. Each Unitholder Should Therefore Consult the Unitholder’s Tax Advisor About the Federal, State and Local Tax Consequences to the Unitholder of the Ownership of Units.

The sections entitled “Federal Income Tax Consequences” and “Risk Factors — Tax Considerations” appearing in the Prospectus set forth, respectively, a discussion of the material federal income tax matters of general application of the acquisition, ownership and sale of the Units acquired in the Public Offerings and a discussion of certain risk factors associated with matters of federal income taxation as applied to the Trust and such Unitholders. A copy of such sections of the Prospectus is filed as an exhibit to this Form 10-K and is incorporated herein by reference.

In connection with the registration of the Units for offer and sale in the Public Offerings, Dominion Resources and the Underwriters received certain opinions of special counsel (“Special Counsel”) to Dominion Resources (upon which the Trustee and the Delaware Trustee were entitled to rely), including, without limitation, opinions as to the material federal income tax consequences of the ownership and sale of the Units acquired in either of the Public Offerings. Each of these opinions was based on provisions of the Code existing as of June 28, 1994, with respect to the opinions given in connection with the Initial Public Offering, and as of June 8, 1995, with respect to the opinions given in connection with the Secondary Public Offering, and existing and proposed regulations thereunder, administrative rulings and court decisions as of such dates, all of which are subject to changes that may or may not be retroactively applied. Some of the applicable provisions of the Code have not been interpreted by the courts or the Internal Revenue Service (“IRS”). In addition, such opinions were based on various representations as to factual matters made by the Company and Dominion Resources in connection with the Public Offerings. In addition, such opinions were expressly limited in their application to investors purchasing Units in each of such Public Offerings and, as a result, provide no assurance to investors not purchasing Units in one of the Public Offerings.

Neither the Trustee, the Delaware Trustee, nor counsel to the Trustee, respectively, has rendered any opinions with respect to any tax matters associated with the Trust or the Units.

At the time of the Public Offerings, no ruling was requested by Dominion Resources, as the sponsor of the Trust, the Trustee or the Delaware Trustee from the IRS with respect to any matter affecting the Trust or Unitholders. No assurance can be provided that the opinions of Special Counsel (which do not bind the IRS) will not be challenged by the IRS or will be sustained by a court if so challenged.

Summary of Certain Federal Income Tax Consequences

The following summary of certain federal income tax consequences of acquiring, owning and disposing of Units is based on the opinions of Special Counsel to Dominion Resources on federal income tax matters, which are set forth in the Prospectus, and is qualified in its entirety by express reference to the sections of the Prospectus identified in the first paragraph of this “Federal Income Tax Considerations” section. Although the Trustee believes that the following summary contains a description of all of the material matters discussed in the opinions referenced above, the summary is not exhaustive and many other provisions of the federal tax laws may affect individual Unitholders. Furthermore, the summary does not purport to be complete or address the tax issues potentially affecting Unitholders acquiring Units other than by purchase through either of the Public Offerings. Each Unitholder should consult the Unitholder’s tax advisor with respect to the effects of the Unitholder’s ownership of Units on the Unitholder’s personal tax situation.

Coal seam gas produced and sold after December 31, 2002 will no longer generate Section 29 tax credits unless the Section 29 tax credit is extended or reinstated by Congress. Nevertheless, the Section 29 tax credit may be available to Unitholders with respect to the first quarter of 2003 because, among other reasons, it is attributable to coal seam gas produced and sold on or before December 31, 2002. The Trustee is seeking a private letter ruling from the IRS on this issue. All discussions of Section 29 tax credits are applicable only to those credits attributable to coal seam gas produced and sold on or before December 31, 2002.

Classification and Taxation of the

Trust The Trust is a grantor trust and not an association taxable as a corporation. As a grantor trust, the Trust is not subject to federal income tax. There can be no assurance that the IRS will not challenge this treatment. The tax treatment of the Trust and Unitholders would be materially different if the IRS were to successfully challenge this treatment.

Limits on Deductions and Credits

Generally, a taxpayer is entitled to claim deductions and tax credits generated by an investment only if the investment has economic substance. The application of this principle in the context of the production and sale of nonconventional fuels (like coal seam gas) that generated the Section 29 tax credit is uncertain because such application has not been addressed either by a court or the IRS. An investment has economic substance if the investor can demonstrate that there is a reasonable possibility of deriving an economic profit from the investment in excess of a de minimis amount, apart from tax benefits. In many cases, economic profit has been computed by comparing the taxpayer’s total cash investment to the total cash reasonably expected to be received by the taxpayer as a result of the investment (a “Pre-Tax Profit Objective”). At the time of the Public Offerings, Special Counsel to Dominion Resources expressed the opinion (only in connection with the Public Offerings) that the ownership of Units purchased in either of the Public Offerings, which ownership is not subject to puts, calls or other risk allocation devices, has economic substance even if the owner has no Pre-Tax Profit

Objective. No assurance is given either by the Trustee or counsel to the Trustee to a purchaser of Units in or following the Public Offerings as to whether (and to what extent) such purchaser is or will be entitled to claim deductions and the Section 29 tax credit generated with respect to such Units.

Taxation of Unitholders Each Unitholder is taxed directly on his proportionate share of income, deductions and credits of the Trust attributable to the Royalty Interests consistent with each such Unitholder's taxable year and method of accounting and without regard to the taxable year or method of accounting employed by the Trust.

Income and Deductions The income of the Trust consists primarily of a specified share of the proceeds from the sale of coal seam gas produced from the Underlying Properties. During 2003, the Trust earned interest income on funds held for distribution and made adjustments to the cash reserve maintained for the payment of contingent and future obligations of the Trust. The deductions of the Trust consist of severance taxes and administrative expenses. In addition, each Unitholder is entitled to depletion deductions. See "Unitholder's Depletion Allowance" below.

Individuals may deduct "miscellaneous itemized deductions" (including, in general, investment expenses) only to the extent that such expenses exceed 2 percent of the individual's adjusted gross income. Although there are exceptions to the 2 percent limitation, authority suggests that no exceptions apply to expenses passed through from a grantor trust, like the Trust.

Section 29 Tax Credits Unitholders are entitled, provided certain requirements are met, to claim tax credits pursuant to Section 29 of the Code with respect to sales before January 1, 2003, of coal seam gas production attributable to the Royalty Interests and produced from the Existing Wells, the gross income from which is included in their taxable income. The Section 29 tax credit provides a taxpayer a dollar-for-dollar reduction in his regular federal income tax liability and, therefore, generally provides him a greater benefit than a deduction, which merely reduces the amount of his taxable income. Unitholders will not be entitled to the Section 29 tax credit for distributions received in the last three quarters of 2003. The Section 29 tax credit may be available to Unitholders for distributions received in the first quarter of 2003 because, among other reasons, it is attributable to coal seam gas produced and sold on or before December 31, 2002. Allowing Unitholders to take Section 29 tax credits on their 2003 tax returns for coal seam gas produced and sold in the fourth quarter of 2002 is consistent with how Unitholders have reported the income and Section 29 tax credits from fourth quarter production throughout the life of the Trust. Such reporting matches the income recognition with the associated credits. Therefore, the Trust believes that Unitholders should be entitled to take the Section 29 tax credit amount on their 2003 tax returns.

To confirm that Unitholders may take the Section 29 tax credit amount reported herein on their 2003 tax returns, the Trust has

filed a private letter ruling request with the IRS. This ruling request is pending. Therefore, the Trust does not yet know whether the IRS agrees that Unitholders may report the Section 29 tax credit amount reported herein on their 2003 tax return. The IRS may take the position that Unitholders may not take the Section 29 tax credit on their 2003 tax returns because Unitholders did not receive the income attributable to fourth quarter 2002 production until 2003, after the Section 29 tax credit had expired. Once the IRS issues a ruling, the Trustee will notify Unitholders as promptly as possible.

Unitholders may choose to file their tax returns before the IRS issues its ruling or to file an extension of time to file their returns while the ruling request is pending. An extension of time to file, however, is not an extension of time to pay tax. Therefore, if Unitholders choose to take the Section 29 tax credit when calculating their 2003 tax liability and an adverse ruling is subsequently issued or the pending ruling request is withdrawn because the IRS notifies the Trust that it expects to issue an adverse ruling, Unitholders may be liable for additional tax, penalties, and interest. If Unitholders choose not to take the Section 29 tax credit when calculating their 2003 tax liability and a favorable ruling is subsequently issued, Unitholders may take the Section 29 tax credit on their original returns, if filed thereafter, or on an amended return and claim a refund for any overpayment of tax resulting from the allowance of the Section 29 tax credit.

Section 29 tax credit information is reported herein only for the first quarter of 2003. For a Unitholder who owned Units of record on the first quarterly record date of 2003, the available Section 29 tax credit (if allowed) is approximately \$0.203285 per Unit, based on the first estimate of the GNP implicit price deflator published by the Bureau of Economic Analysis.

The availability of Section 29 tax credits is dependent upon meeting a number of requirements, many of which are factual in nature. The Company and Dominion Resources represented only in connection with the Public Offerings that those factual requirements were met. At the time of each of the Public Offerings, Special Counsel opined as to those requirements that are statutory or legal in nature. If any of the factual requirements are not met, or the opinion not followed, some or all of the expected Section 29 tax credits may not be available.

Production from coal seam gas wells drilled after December 31, 1979 and prior to January 1, 1993, qualifies for the Section 29 tax credit, so long as the wells are certified by the Federal Energy Regulatory Commission ("FERC"). For a discussion of the well certification requirement and its impact on the wells included within the Underlying Properties, see Note 3 to the Financial Statements.

Limits on Unitholder's Use of
Section 29 Tax Credits

The Section 29 tax credit is based on the Unitholder's pro rata share of qualifying production. It can be used only to the extent

that a Unitholder's regular tax liability exceeds the Unitholder's tentative minimum tax liability after the regular tax liability has been reduced by the foreign tax credit and certain other nonrefundable personal credits. Any part of the Section 29 tax credit not allowed for the tax year solely because of this alternative minimum tax limitation is subject to certain carryover provisions relating to the alternative minimum tax calculation. Except for the foregoing, there are no Code provisions that allow for the carryback or carryforward of Section 29 tax credits in any other circumstances. As the carryforward of unused Section 29 tax credits is related to the alternative minimum tax calculation for succeeding years, carryforwards should be allowed, even if the Section 29 tax credit is not extended or reinstated after 2002.

Quarterly Allocations of
Section 29 Credits

Under the Code, a Unitholder is entitled to Section 29 tax credits only to the extent that he is an owner of the economic interest at the time the coal seam gas was produced. The Trustee allocates the income received by the Trust for a quarter, and the Section 29 tax credit allocable to such income, to Unitholders of record on the quarterly record date for such quarter. Such an allocation may be challenged by the IRS, but any challenge is likely to have a material adverse effect only if successful and only for Unitholders who do not own Units for a full quarter for each record date, particularly Unitholders who acquire Units shortly before a record date and sell shortly after a record date. At the time of each of the Public Offerings, Special Counsel declined to express an opinion as to whether the IRS would accept quarterly allocations or would require income, credits and deductions of the Trust to be determined and allocated daily based on ownership at the time of production or on some other basis.

Treatment of the Royalty
Interests

Each Royalty Interest is a nonoperating economic interest in an Underlying Property because it is a right to a fixed percentage of the gross proceeds from the sale of gas as, if and when produced from such properties, the right endures for the economic life of the burdened reserves and the right is not required to bear any cost of developing or producing such gas.

Unitholder's Depletion Allowance
.....

Each Unitholder is entitled to amortize the cost of the Units through cost depletion over the life of the Royalty Interests (or, if greater, through percentage depletion equal to 15 percent of gross income). If any portion of the Royalty Interests is treated as a production payment or is not treated as an economic interest, however, a Unitholder will not be entitled to depletion in respect of such portion. No depletion allowances were available to Unitholders in respect of production from the Royalty Interests prior to June 28, 1994.

Depletion Recapture

If a taxpayer disposes of any "section 1254 property" (certain oil, gas, geothermal or other mineral property), and if the adjusted basis of such property includes adjustments for deductions for depletion under Section 611 of the Code, the taxpayer generally

must recapture the amount deducted for depletion in ordinary income (to the extent of gain realized on the disposition of the property). This depletion recapture rule applies to any disposition of property that was placed in service by the taxpayer after December 31, 1986. Detailed rules set forth in Sections 1.1254-1 through 1.1254-6 of the United States Treasury regulations govern dispositions of property after March 13, 1995. The Service will likely take the position that a Unitholder who purchases a Unit subsequent to December 31, 1986, must recapture depletion upon the disposition of that Unit.

Non-Passive Activity Income,

Credits and Loss

The income, credits and expenses of the Trust are not taken into account in computing the passive activity losses and income under Section 469 of the Code for a Unitholder who acquires and holds Units as an investment and did not acquire them in the ordinary course of a trade or business. Section 29 tax credits generated by an investment in Units can be utilized to offset regular tax liability on income from any source whether active or passive, subject to other limitations discussed herein or arising from the individual tax circumstances of each Unitholder. See "Limits on Unitholder's Use of Credits" above.

Tax Shelter Registration

The Trust is registered as a "tax shelter," and its tax shelter registration number is 94-277000355. Issuance of a tax shelter registration number does not indicate that the investment in Units or the claimed tax benefits have been reviewed, examined or approved by the IRS.

Substantial Understatement

Penalty

Section 6662 of the Code imposes a penalty in certain circumstances for a substantial understatement of taxes if a taxpayer's tax liability is understated by more than the greater of (i) 10 percent of the taxes required to be shown on the return or (ii) \$5,000 (\$10,000 for most corporations). The penalty (which is not deductible) is 20 percent of the understatement.

Except in the case of understatements attributable to "tax shelter" items, which are subject to special rules discussed below, an item of understatement will not give rise to the penalty if: (i) there is or was "substantial authority" for the taxpayer's treatment of the item, (ii) all the facts relevant to the tax treatment of the item are adequately disclosed on the return or on a statement attached to the return and there is a reasonable basis for the tax treatment of such item, or (iii) there is reasonable cause and the taxpayer acted in good faith.

In the case of understatements attributable to "tax shelter" items by noncorporate taxpayers, the substantial understatement penalty may be avoided only if: (i) the taxpayer establishes that, in addition to having substantial authority for his position, he reasonably believed that the treatment claimed was more likely than not the proper treatment of the item, or (ii) there is reasonable cause and the taxpayer acted in good faith. In the case of understatements attributable to "tax shelter" items by corpo-

rate taxpayers, effective for transactions occurring after December 8, 1994, the substantial authority and reasonable belief exception does not apply. Accordingly, in a transaction occurring after December 8, 1994, if a corporate taxpayer has a substantial understatement attributable to a “tax shelter” item, penalties apply unless the corporate taxpayer can show reasonable cause and good faith. For transactions involving corporate taxpayers and substantial understatements attributable to “tax shelter” items occurring before December 9, 1994, the rules applicable to noncorporate taxpayers apply. A “tax shelter” item is an item (e.g., income, gain, loss, deduction, credit) attributable to a partnership or other entity, any investment plan or arrangement, or any other plan or arrangement, if a significant purpose of such partnership, entity, plan or arrangement is the avoidance or evasion of income tax. For transactions entered into before August 6, 1997, the relevant standard is whether tax avoidance or evasion of income tax was the principal purpose of the entity, plan, or arrangement.

No assurance is given either by the Trustee or counsel to the Trustee as to the possible application of this penalty or any other penalties, in part because such application depends largely upon the individual circumstances under which the Units were acquired. As a result, purchasers of Units in and after the Public Offerings should consult their personal tax advisors.

Unitholder Reporting
Information

The Trustee furnishes to Unitholders tax information concerning royalty income, depletion and the Section 29 tax credits on an annual basis. Year-end tax information is furnished to Unitholders no later than March 15 of the following year. See third paragraph under “Description of Units—Periodic Reports.”

The amount of the Section 29 tax credit on coal seam gas is adjusted annually for inflation. In the spring of each year, the IRS issues a notice publishing the inflation factor for the preceding calendar year. The notice issued in the spring of 2003 states that the calendar year 2002 inflation-adjusted credit applies to the sales of qualified fuels sold during the 2002 calendar year. If the IRS allows Section 29 tax credits to be claimed on 2003 tax returns, it is unknown whether the IRS will issue a notice in the spring of 2004 with a new inflation factor or whether the inflation factor published last year will continue to apply.

The Trustee has used the first estimate of the GNP implicit price deflator published by the Bureau of Economic Analysis for calendar year 2003 in determining the amount of the Section 29 tax credit in the schedules included in this booklet. If the IRS issues a notice with an inflation factor for calendar year 2003, the Trustee will furnish Unitholders with such information in the quarterly report to Unitholders immediately following the publication of such information. However, if such information differs materially from the Trustee’s estimate, the Trustee will promptly mail this information to each Unitholder.

ERISA CONSIDERATIONS

The section entitled “ERISA Considerations” appearing in the Prospectus sets forth certain information regarding the applicability of the Employee Retirement Income Security Act of 1974, as amended (“ERISA”), and the Code to pension, profit-sharing and other employee benefit plans and to individual retirement accounts (collectively, “Qualified Plans”). A copy of this section of the Prospectus is filed as an exhibit to this Form 10-K and is incorporated herein by reference.

Due to the complexity of the prohibited transaction rules and the penalties imposed upon persons involved in prohibited transactions, it is important that potential Qualified Plan investors consult their counsel regarding the consequences under ERISA and the Code of their acquisition and ownership of Units.

STATE TAX CONSIDERATIONS

The Following is Intended as a Brief Summary of Certain Information Regarding State Income Taxes and Other State Tax Matters Affecting the Trust and Unitholders. Unitholders Should Therefore Consult the Unitholder’s Tax Advisor Regarding State Income Tax Filing and Compliance Matters.

Alabama Income Tax

All revenues attributable to the Royalty Interests are derived from sources within the State of Alabama. Alabama imposes an income tax on individuals, corporations (subject to certain exceptions for S corporations) and certain other entities that are residents of, conduct business in, or derive income from sources within Alabama. Under general rules of application, both resident and nonresident Unitholders would be required to file annual Alabama income tax returns and pay Alabama income taxes with respect to any income received from the Trust and would be subject to penalties for failure to comply with those rules.

The Alabama Department of Revenue (the “DOR”) has issued a letter ruling that permits the Trust to file a “composite income tax return” on behalf of all Unitholders who are not residents of Alabama. The filing of the composite income tax return and acceptance of the return by DOR will relieve those nonresident Unitholders of any obligation to file Alabama state income tax returns. The Trust filed for each of the years 1995-2002 composite income tax returns with the DOR on behalf of all Nonresident Unitholders (defined below), and intends to file a composite return for 2003 and each year thereafter for so long as the composite return does not report any taxable income for Alabama state income tax purposes. Based on certain assumptions, the composite income tax return to be filed by the Trust on behalf of Nonresident Unitholders will show a net taxable loss for 2003. Accordingly, no Alabama state income tax is due under the 2003 return.

No assurance can be given, however, that the DOR will accept the assumptions used by the Trust in preparing and filing the composite income tax return for any year and determining the composite taxable income or loss thereunder for Alabama state income tax purposes. If all or a portion of those assumptions are not acceptable to the DOR, the DOR may require the Trust to recompute and refile one or more composite income tax returns based on different assumptions acceptable to the DOR. If the composite income tax return for 2003 (or any other tax year) as initially filed by the Trust is not accepted as filed by the DOR, the Trust may decide not to refile a composite income tax return either (i) because the Trust would have net Alabama taxable income for that year as a result of the assumptions required by the DOR or (ii) because the refiling of the composite income tax return imposes an unreasonable burden on the Trust in the judgment of the Trustee (based on its sole discretion). In that event, each Nonresident Unitholder would be required to file a separate Alabama state income tax return and pay any Alabama state income tax due as well as any penalties and interest due thereon. For purposes of the filing of the composite income tax return for any taxable year, “Nonresident Unitholders” will consist of those Unitholders to whom the Trust has provided an

individualized tax information letter (together with its tax information booklet) for such tax year that shows a mailing address outside the State of Alabama. All other Unitholders will be treated by the Trust for purposes of the filing of the composite income tax return as "Resident Unitholders."

The filing of the composite income tax return by the Trust does not relieve any resident of the State of Alabama or any Resident Unitholder from the obligation to file an Alabama state income tax return individually (and pay Alabama state income tax thereon, if any) with respect to the revenues and expenses attributable to the Royalty Interests. In light of the foregoing, each Unitholder should consult his tax adviser regarding the requirements for filing state income tax returns for his state of residence and Alabama.

Alabama Business Privilege Tax

Alabama previously imposed a franchise tax on domestic corporations and foreign corporations doing business in Alabama, under a broad definition of "corporation" in the state constitution, based on the amount of a corporation's "capital employed" in the state. In reliance upon the representations and assumptions set forth in the Prospectus and on a private letter ruling issued June 10, 1994, by the DOR as to the offering of the Units, special Alabama tax counsel to the Company opined in connection with each of the Public Offerings that the Trust was not subject to Alabama franchise tax. Although the Alabama Commissioner of Revenue has the authority to revoke retroactively DOR rulings under certain limited circumstances, special Alabama tax counsel did not believe, based on the above representations and assumptions, that those circumstances existed with respect to the Company's private letter ruling. Dominion Resources agreed to indemnify the Trust against any resulting Alabama franchise tax imposed on the Trust.

The Alabama franchise tax has been repealed and replaced with the Alabama business privilege tax, which imposes an annual privilege tax on corporations, limited liability entities, and disregarded entities (as those terms are statutorily defined in Alabama's tax code) doing business in Alabama or organized under Alabama law. The DOR issued a revenue ruling in 2002 holding that the business privilege tax applied to a grantor trust. The DOR had previously issued a revenue ruling holding that the business privilege tax did not apply to a grantor trust, but that revenue ruling was revoked. Alabama tax counsel recently advised the Trustee that the Trust has been subject to the business privilege tax since 2000. The Trustee intends to comply with its obligations relating to the business privilege tax and will file the appropriate returns and pay any applicable tax, interest, and penalties.

Alabama Severance Taxes

Alabama levies severance taxes on the removal of certain natural resources. Statewide severance taxes are collected from oil, gas, coal, forest products and iron ore. Additional severance taxes are collected by certain counties on oil, gas, coal, stone, rock, clay, sand and gravel. Therefore, the Trust, as owner of the Royalty Interests, bears its proportionate share of Alabama state and county severance taxes. To the extent there is an increase in the amount of severance taxes, the cash distribution amount payable to Unitholders will decrease.

Other Alabama Taxes

The Trust has been structured to cause the Units to be treated as interests in intangible personal property rather than as interests in real property for certain Alabama state law purposes, other than income and business privilege taxation. If the Units are held to be real property or as interests in real property under the laws of Alabama, Unitholders could be subject to Alabama probate laws, and estate and similar taxes, whether or not they are residents of Alabama.

REGULATION AND PRICES

Regulation of Natural Gas

Certain aspects of production, transportation, marketing and sale of natural gas from the Underlying Properties may be subject to federal and state governmental regulation, including regulation of transportation tariffs charged by pipelines, taxes, the prevention of waste, the conservation of natural gas, pollution controls and various other matters.

Sales of natural gas produced from the Underlying Properties are considered to be sold at the wellhead (as opposed to downstream sales or resales) for purposes of pricing and, therefore, are not subject to federal regulation.

The transportation of natural gas in interstate commerce is subject to federal regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act ("NGA") and the Natural Gas Policy Act of 1978. In past years, FERC has adopted regulatory policy changes that have affected the transportation of natural gas from the wellhead to the market. Interstate pipelines no longer perform a merchant function. Gas producers now sell gas to end users or market accumulators rather than into the system supply of an interstate pipeline who would then resell it. Transportation of gas on interstate pipelines is now on an "open access" basis and interstate pipelines have been required to unbundle their services with the result that customers now only pay for the services they require. The interstate pipeline connected to the gathering system for the underlying properties is subject to the regulations described above.

In the past, Congress has been very active in the area of natural gas regulation. At the present time, it is impossible to predict 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 Underlying Properties and the Trust.

The State Oil and Gas Board of Alabama regulates the production of natural gas, including requirements for obtaining drilling permits, the method of developing new fields, provisions for the unitization or pooling of natural gas properties, the spacing, operation, plugging and abandonment of wells and the prevention of waste of natural gas resources. The rate of production may be regulated, and the maximum daily production allowable from natural gas wells may be established on a market demand or conservation basis or both. Reductions in allowable production may extend the timing of recovery of reserves. Although the Trust is not aware of any pending or contemplated proceedings to change allowable rates of production from the Underlying Properties, there can be no assurances made that such changes will not be made. The Unitholders and the Trust will not have any control over such changes. Reductions in the allowable production from the Underlying Properties could affect the timing or amount of distributions to Unitholders.

Environmental Regulation

Operations on the Underlying Properties associated with the production of natural gas are subject to numerous federal and state laws, rules and regulations governing the discharge of materials into the environment or otherwise relating to the protection of the environment. Such laws, rules and regulations require the acquisition of certain permits, impose substantial liabilities for pollution resulting from exploration and production operations and may also restrict air or other pollution resulting from operations. It is possible that federal and state environmental laws and regulations will become more stringent in the future. For instance, legislation has been proposed in Congress in connection with the pending reauthorization of the Federal Resource Conservation and Recovery Act ("RCRA") that would amend RCRA to reclassify certain oil and gas production wastes as "hazardous waste." If adopted, this amendment would result in more rigorous and expensive disposal requirements. It is impossible to predict what the precise effect additional regulation or legislation, or enforcement policies thereunder, could have on the operation of the Underlying Properties. However, any costs or expenses incurred by the Company in connection with environmental liabilities arising out

of or relating to activities occurring on, in or in connection with, or conditions existing on or under, the Underlying Properties, will be borne by the Company and not the Trust, and such costs and expenses will not be deducted in calculating Gross Proceeds. Such costs and expenses may, however, be taken into account by the Company in exercising its rights to abandon a well and may accelerate the termination of the Trust. See “Properties—The Royalty Interests—Sale and Abandonment of Underlying Properties” and “Properties—Description of the Trust—Termination and Liquidation of the Trust.”

Water from the operations on the Underlying Properties is discharged into the Black Warrior River pursuant to a National Pollutant Discharge Elimination System permit issued by the Alabama Department of Environmental Management (“ADEM”). ADEM initially issued 5 permits in connection with the Underlying Properties, which were consolidated into one permit in February 1994. The ADEM permit was renewed in 1999 and will expire in July 2004. Renewal of the permit has been applied for and is under review by the Alabama Department of Environmental Management. It generally authorizes water disposal based upon the Black Warrior River’s minimum flow rate and maximum chloride level. The Company has advised the Trust that since 1987 water disposal from the Underlying Properties has not been disrupted.

While the Company has informed the Trust that it believes the Underlying Properties are in material compliance with all environmental laws and regulations, such regulations have generally become more stringent and costly over time. As a royalty holder, the Trust may not be directly subject to increased costs; however, such costs may be taken into account by the Company in exercising its rights to abandon a well, which may accelerate the termination of the Trust. The Company has informed the Trust that it estimates that it plans to expend approximately \$70,000 during 2004 for anticipated expenditures related to compliance with environmental laws.

Competition, Markets and Prices

The revenues of the Trust and the amount of cash distributions to Unitholders depend upon, among other things, the effect of competition and other factors in the market for natural gas. The natural gas industry is highly competitive in all of its phases. The Company encounters competition from major oil and gas companies, independent oil and gas concerns and individual oil and gas producers and operators. Many of these competitors have greater financial and other resources than the Company. Competition may also be presented by alternative fuel sources, including heating oil and other fossil fuels.

Demand for natural gas production has historically been seasonal in nature and prices for natural gas fluctuate accordingly. Unseasonably warm weather and the ability of markets to access storage can cause the demand for natural gas to decrease, resulting in lower prices received by producers than when demand is higher due to seasonal weather factors. Such price fluctuations and the continuation of low prices for natural gas will directly impact Trust distributions, estimates of reserves attributable to the Royalty Interests and estimated future net revenue from reserves attributable to the Royalty Interests.

Prices for natural gas are subject to wide fluctuations in response to relatively minor changes in supply, market uncertainty and a variety of additional factors that are beyond the control of the Trust and the Company. These factors include political conditions in the Middle East, the price and quantity of imported oil and gas, the level of consumer product demand, the severity of weather conditions, government regulations, the price and availability of alternative fuels and overall economic conditions. Additionally, lower natural gas prices may reduce the amount of gas that is economic to develop or produce from the Underlying Properties.

The Trust’s revenues and distributions to Unitholders will be primarily dependent on the sales prices for Gas produced from the Underlying Properties and the quantities of Gas sold. Natural gas prices have historically been volatile and are likely to continue to be volatile. Price volatility and the risk of production curtailment make it difficult to estimate the future levels of cash distributions to

Unitholders or the value of the Units. Since the termination of the Gas Purchase Agreement, Gas is sold on a month to month basis to various purchasers until such time as a long term contract can be secured. See "Properties — The Royalty Interests — Gas Purchase Agreement."

Item 2. Properties.

THE ROYALTY INTERESTS

The Royalty Interests held by the Trust generally entitle the Trust to receive 65 percent of Gross Proceeds. The Royalty Interests were conveyed to the Trust by means of a single instrument of conveyance. The Conveyance was recorded in the appropriate real property records in Alabama, so as to give notice of the Royalty Interests to creditors, and any transferees will take an interest in the Underlying Properties subject to the Royalty Interests. The Conveyance was intended to convey the Royalty Interests as real property interests under Alabama law.

The following description of the material provisions of the Conveyance and the Trust Agreement is subject to and qualified by the more detailed provisions of the Conveyance and the Trust Agreement included as exhibits to this Form 10-K.

The Underlying Properties

Black Warrior Basin. The Black Warrior Basin covers 6,000 square miles in west central Alabama and contains 7 Pennsylvania-age multi-seam coal groups in the Pottsville formation: the Black Creek, Mary Lee, Pratt, Cobb, Gwin, Utley and Brookwood coal groups. The Pottsville coal formation ranges from the surface to a depth of 4,100 feet.

Wells in the Black Warrior Basin produce natural gas from coal seam formations that have production characteristics materially different from conventional natural gas wells. The primary factor affecting recovery of gas reserves from coal seams in the Black Warrior Basin is the lowering of reservoir pressure through "dewatering" operations. In a typical coal seam gas well on the Underlying Properties, average daily natural gas production generally will increase as wells are "dewatered" until natural gas production reaches a "peak" at which time natural gas production will decline. The amount of time necessary to "dewater" a well and cause it to reach its peak production, and the ultimate level of a well's peak production, are difficult to estimate. Since all of the 532 wells included in the Underlying Properties were producing by mid-1991, the Company believes that production from such wells is currently past its peak and will decline over the term of the Trust.

The Royalty Interests were conveyed by the Company to the Trust out of the Company Interests. The Existing Wells are operated by Dominion Black Warrior Basin, Inc. in accordance with the Operating Agreement. See "—Operation of Properties." The Underlying Properties comprise 34,212 gross acres of land in an area approximately 5 miles wide and 23 miles long located on the Tuscaloosa to Bankhead Lake portion of the Black Warrior Basin. Initial production began in December 1988 and consisted of 8 wells. The Company acquired its interest in the Underlying Properties in December 1992. As of December 31, 2003, the Underlying Properties contained 532 wells that were producing gas, all of which were drilled prior to 1993.

Well Count and Acreage Summary. The following table shows as of December 31, 2003, the gross and net producing wells and acres for the Company Interests. The net wells and acres are determined by multiplying the gross wells or acres by the Company Interests Owner's working interest in the wells or acres.

	Number of Wells		Acres	
	Gross	Net	Gross	Net
Company Interests.....	532	519	34,212	33,391

Royalty Interests, Company Interests and Retained Interests. On June 1, 1994, the effective date of the Conveyance, the Company had an average aggregate working interest in the Existing Wells of approximately 98 percent, and an average aggregate net revenue interest of approximately 80 percent in the Existing Wells. The Company has not sold or otherwise disposed of any of its interest in the Company Interests since June 1, 1994. The Royalty Interests are entitled to approximately 52 percent of the net revenue from natural gas produced and sold from the Underlying Properties, and the interests (the "Retained Interests") of the Company in the Underlying Properties (after giving effect to the Royalty Interests) entitle the Company to receive approximately 28 percent of the net revenue from the natural gas produced and sold from the Underlying Properties. As a working interest owner in the Underlying Properties, the Company is responsible for an average of approximately 98 percent of the operating costs of the Existing Wells.

The Royalty Interests do not burden (i) royalties and other obligations, expressed or implied, under oil or natural gas leases, (ii) the overriding royalties and other burdens created by the Company's predecessors in title, or (iii) the working interests owned by other individual working interest owners.

Water Removal and Disposal. Water from the wells located on the Underlying Properties is pumped from the wellhead to one of 5 water disposal systems, each with 2 ponds, where the water is analyzed and chemically treated to remove impurities, if necessary, prior to discharge into the Black Warrior River. Water from the operations on the Underlying Properties is discharged into the Black Warrior River pursuant to a National Pollutant Discharge Elimination System permit issued by ADEM that will expire in July 2004. A new permit has been requested for post-July 2004. The ADEM permit generally authorizes water disposal based upon the Black Warrior River's minimum flow rate and maximum chloride level. The Company has advised the Trust that, since 1987, water disposal from the Underlying Properties has not been disrupted. Although the facilities of the Company have the capacity to store several days of water production, if water disposal into the Black Warrior River is disrupted, natural gas production from the wells on the Underlying Properties would be curtailed during the period of such disruption. See "Business—Regulation and Prices—Environmental Regulation."

Curtailments. The Company has advised the Trust that, during 2003, production from the Underlying Properties was not curtailed for any reason other than for routine maintenance.

Federal Lands. Approximately one percent (360 acres) of the Underlying Properties are leases on land held by the federal government. Royalty payments due to the U.S. government for natural gas produced from federal lands included in the Underlying Properties must be calculated in conformance with a working interest owner's interpretation of regulations issued by the Minerals Management Service ("MMS"). MMS regulations cover both valuation standards, which establish the basis for placing a value on production, and cost allowances, which define those post-production costs that are deductible by the lessee.

The Trust is subject to certain rules of the Bureau of Land Management under which the holding of interests in leases by persons other than citizens, nationals and legal resident aliens of the United States ("Eligible Citizens") are limited. As a result, non-Eligible Citizens are prohibited from owning Units. If any Units are acquired by persons or entities not constituting Eligible Citizens, such Unitholders may be required to sell such Units pursuant to a procedure set forth in the Trust Agreement. See "Business—Description of the Trust—Possible Divestiture of Units."

Additional Wells. Well spacing rules, which are in effect in Alabama, generally govern the space between wells drilled to the same productive formation and are promulgated in order to prevent waste and confiscation of property. Pursuant to such rules, the Existing Wells are located on 40- to 80-acre spacing units. Exceptions or changes to these rules may be granted by the applicable regulatory agency upon application of an interested party following notice to other interested parties if, in the agency's opinion, good reasons exist therefor after consideration of evidence presented by the applicant and any opponents. The Company has informed the Trust that it is not aware of any plans to change spacing

regulations with respect to the Underlying Properties in Alabama. No assurances can be made, however, that exceptions or changes will not be made in the future.

The Company and its affiliates or unrelated third parties may acquire interests in properties adjoining the Underlying Properties. It is possible that wells drilled on adjoining properties would drain reserves attributable to the Underlying Properties.

The Company has agreed for the term of the Trust not to consent to, cooperate with, assist in or conduct infill drilling (except as required by law) on any of the Underlying Properties in which the Company owned an interest as of June 1, 1994. Although the Company believes that it is unlikely that any additional wells will be drilled, if the Operating Agreement is terminated, the Company cannot prevent one of the other owners of an interest in the Underlying Properties from drilling additional wells on the Underlying Properties. Additional wells, if drilled, could recover a portion of the reserves otherwise producible from wells burdened by the Company Interests, thereby reducing the Gross Proceeds attributable to the Royalty Interests.

If additional wells are drilled, Section 29 tax credits will not be generated from production attributable to such additional wells unless the Section 29 tax credit is extended or reinstated and the drilling requirement is changed.

The Royalty Interests

Summary of Conveyance. The Conveyance has been filed as an exhibit to this Form 10-K. The following summary of the material terms of the Conveyance is qualified in its entirety by reference to the terms thereof as set forth in such exhibit.

Expenses Borne by Royalty Interests. The Royalty Interests are non-operating, non-expense bearing interests, except for their share of property, production and related taxes, including severance taxes. Accordingly, owners of the Royalty Interests are not liable or responsible for costs or liabilities incurred by the working interest owners in connection with the production of Gas from the Underlying Properties.

Operating Standard. The Company Interests Owner is obligated to conduct and carry on, as would a reasonably prudent operator, or cause to be so conducted or carried on, the development, maintenance and operation of the Company Interests.

Infill Drilling. The Company Interests Owner has agreed not to consent to, cooperate with, assist in or conduct any infill drilling on the Underlying Properties, except as required by law.

Pratt Recompletions. To recover behind pipe reserves, the Company Interests Owner recompleted certain of the Existing Wells to the Pratt coal seam prior to March 31, 1997. To the extent that production from the recompleted wells qualifies for the Section 29 tax credit, such production is taken into account by the Trustee when computing the Tax Credit per Unit furnished annually to Unitholders.

Right to Take In-Kind. The owner of the Royalty Interests has no right to take production in-kind.

Pooling and Unitization. The Company Interests Owner has certain pooling and unitization rights.

Right to Assign Company Interests. The Company Interests Owner has the right to assign all or any part of the Company Interests, subject to the Royalty Interests and the terms and provisions of the Conveyance. If any such assignment is made of part, but not all, of such interests, then effective as of the date of such assignment, the assignee will be required to make a separate computation of Gross Proceeds attributable to the assigned interests.

Sale or Assignment of Royalty Interests. In certain situations, the Trust may sell or dispose of all or a part of the Royalty Interests, in which case the Trust would receive the proceeds therefrom and distribute such proceeds to the Unitholders, net of any amounts held as a reserve. See

“Business—Description of the Trust—Transfer of Royalty Interests” and “Business—Description of the Trust—Duties and Limited Powers of the Trustee.”

Books and Records. The Company Interests Owner is required to maintain books and records sufficient to determine the amounts payable with respect to the Royalty Interests.

Computation and Payment. The Royalty Interests entitle the Trust to receive 65 percent of the Gross Proceeds. The Royalty Interests bear their proportionate share of property, production and related taxes (including severance taxes). The definitions, formulas and accounting procedures and other terms governing the computation of the Royalty Interests are set forth in the Conveyance.

The Company Interests Owner is required, pursuant to the Conveyance, to pay to the Trust amounts received by the Company Interests Owner from the sale of Subject Gas attributable to the Royalty Interests. Under the Conveyance, the amounts payable by the Company Interests Owner with respect to the Royalty Interests are computed with respect to each calendar quarter ending prior to termination of the Trust, and such amounts are paid to the Trust not later than the last business day before the 45th day following the end of each calendar quarter. The amounts paid to the Trust do not include interest on any amounts payable with respect to the Royalty Interests that are held by the Company Interests Owner prior to payment to the Trust. The Company Interests Owner is entitled to retain all amounts attributable to the Retained Interests. The Company Interests Owner deducts from the payment to the Trust the Royalty Interests’ share of property, production and related taxes (including severance taxes) and pays the same on behalf of the Trust.

Reserve Estimate

Reserve Estimate. The following table summarizes net proved reserves estimated as of January 1, 2004, and certain related information for the Royalty Interests from the Reserve Estimate prepared by Ralph E. Davis & Associates. The natural gas reserves were estimated by Ralph E. Davis & Associates by applying volumetric and decline curve analyses. All of such reserves constitute proved developed gas reserves. The Reserve Estimate was prepared in accordance with criteria established by the Commission.

<u>Royalty Interests</u>	<u>As of January 1, 2004</u>
Net Proved Natural Gas Reserves (MMcf) (a) (b):	
Developed Producing	41,586
Estimated Future Net Revenues (in thousands) (a) (c):	
2004	\$ 25,111
2005	21,948
2006	19,274
2007	16,944
2008	14,916
Thereafter	<u>113,834</u>
Total	<u>\$212,027</u>
Total Discounted at 10 Percent	<u>\$117,284</u>

(a) The estimates of reserves and future net revenues summarized in this table are based upon an unescalated price of \$5.9168 through December 31, 2003, which was the price being received by the Company under the Gas Purchase Agreement as of January 1, 2004. After December 31, 2003, the price of \$5.9168 per Mcf was utilized, which represented the market price for gas in their fields as of December 31, 2003. This price may not be the most representative price for estimating reserves or related future net revenues data. See “—Gas Purchase Agreement.”

- (b) As discussed in “Business—Federal Income Tax Considerations,” coal seam gas produced and sold after December 31, 2002, will no longer generate a Section 29 tax credit unless the Section 29 tax credit is extended or reinstated by Congress.
- (c) Estimated future net revenues are defined as the total revenues attributable to the Royalty Interests for gas production less the relevant share of production, property and related taxes (including severance taxes). Overhead costs have not been included, nor have the effects of depreciation, depletion and federal income tax. Estimated future net revenues and discounted estimated future net revenues are not intended and should not be interpreted as representing the fair market value for the estimated reserves.

The reserve data set forth herein, which was prepared by Ralph E. Davis & Associates in a manner customary in the industry, is an estimate only, and actual quantities, rates of production and sales prices for natural gas are likely to differ from the estimated amounts set forth herein, and such differences could be significant.

There are many uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production. Reserve engineering is a subjective process of estimating underground accumulations of natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of the geological and engineering evaluation of that data. Results of testing and production subsequent to the date of an estimate may justify revision of such estimate. Further, reserve estimates for any given property may vary from engineer to engineer even though each engineer bases his estimate on common data and utilizes techniques and principles customary in the industry.

For properties with short production histories, reserve estimates in many instances are based upon volumetric calculations and upon analogy to similar types of production or producing fields. Relative to many conventional natural gas producing properties, coal seam gas producing properties in general, and the Underlying Properties in particular, have short production histories. In addition, there are no significant coal seam reservoirs that have been produced to depletion that can be used as analogies to the Underlying Properties.

The discounted estimated future net revenues shown herein were prepared using guidelines established by the Commission and may not be representative of the market value for the estimated reserves.

The reserves attributable to the Royalty Interests are expected to decline substantially during the term of the Trust, and a portion of each cash distribution made by the Trust will, therefore, be analogous to a return of capital. As a result, cash distributions will decrease materially over time. For example, based upon the production estimates set forth in the Reserve Estimate, annual production attributable to the Royalty Interests is estimated to decline from 4.9 Bcf in 2004 to 3.3 Bcf in 2007.

Miscellaneous. Ralph E. Davis & Associates has delivered to the Trust the Reserve Estimate, a summary of which is included as an exhibit to this Form 10-K. Information concerning historical changes in net proved developed reserves attributable to the Royalty Interests, and the calculation of the standardized measure of discounted future net revenues related thereto, is contained in Note 8 of the Notes to the Financial Statements incorporated by reference in Item 8 hereof. Dominion Resources has not filed reserve estimates covering the Royalty Interests with any other federal authority or agency.

Natural Gas Sales Prices and Production

The following table sets forth the actual net production volumes attributable to the Royalty Interests, weighted average property, production and related taxes and information regarding natural gas sales prices for the years ended December 31, 2003, December 31, 2002 and December 31, 2001.

	<u>Year Ended</u> <u>December 31, 2003</u>	<u>Year Ended</u> <u>December 31, 2002</u>	<u>Year Ended</u> <u>December 31, 2001</u>
Production attributable to the Royalty			
Interests (Bcf)	5.1	6.1	7.0
Weighted average property, production and related taxes (per Mcf)	\$.16	\$.15	\$.16
Average Contract Price (per Mcf)	\$4.22	\$3.70	\$2.99

Gas Purchase Agreement

El Paso Merchant Energy—Gas, L.P. (“El Paso”), successor to Sonat Marketing Company (“Sonat Marketing”), was required under the Gas Purchase Agreement to purchase the Gas produced from the Underlying Properties until such agreement was terminated, effective January 31, 2004. Under the agreement, Sonat Marketing (as predecessor to El Paso under the Gas Purchase Agreement) was, in past years, obligated to purchase up to a specified monthly base quantity of Gas for a contract price equal to the Index Price plus a specified premium (between \$.05 and \$.07 per MMBtu) over the Index Price. Until December 31, 1998, the Contract Price paid was subject to a minimum price of \$1.85 per MMBtu and a maximum price of \$2.63 per MMBtu. Beginning effective January 1, 1999, the Contract Price paid was subject to a minimum price of \$2.16 per MMBtu and a maximum price of \$3.07 per MMBtu. Beginning effective January 1, 2000 through December 31, 2000, the price paid on Index Price Quantities to a minimum price of \$2.20 and a maximum price of \$2.82. Prior to April 1, 1996, Sonat Marketing was obligated to purchase Gas production in excess of the specified monthly base quantities at the Index Price. Effective April 1, 1996 through December 31, 1998, the price paid for such Gas production in excess of the specified monthly base quantities was the Index Price plus \$.02. Effective January 1, 1999 through December 31, 2000, the price paid Gas production in excess of the specified monthly basis quantities was the Index Price plus \$.02. The Index Price, which is determined on a monthly basis, was Southern Natural Gas Company’s posted index price for deliveries of gas in Louisiana.

Effective January 1, 2001 through December 31, 2001, the price payable by El Paso for each MMBtu of the base quantity specified for each month was divided into three categories, (i) a fixed price quantity, (ii) an index price quantity subject to a floor and ceiling price (the “Collared Index Quantity”), and (iii) an index price quantity not subject to a floor or ceiling price (the “Non-Collared Index Quantity”). The price paid for each MMBtu of fixed price quantity was \$3.97 per MMBtu. For the amount of gas sold in excess of the fixed price quantity, the price for each MMBtu of gas sold up to the Collared Index Quantity was the Index Price, provided that the price payable each month would in no event be less than \$3.00 per MMBtu or more than \$5.30 per MMBtu. For the amount of Gas sold in excess of the fixed price quantity plus the Collared Index Quantity, the price for each MMBtu of Gas sold was the sum of (a) the Index Price and (b) a premium per MMBtu (ranging from \$.05 to \$.07). The price payable by El Paso for each MMBtu of Gas production in excess of the specified monthly base quantity each month was the sum of the Index Price plus \$.02. Pursuant to a Gas Purchase Agreement amendment, effective January 1, 2002 through December 31, 2002, the price payable by El Paso for each MMBtu for each month was (a) for quantities of Gas up to and including the applicable Monthly Fixed Price Quantity, \$3.70 per MMBtu, and (b) for quantities of Gas over and above the Monthly Fixed Price Quantity up to the Monthly Base Quantity, the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to that same Gas Purchase Agreement amendment, commencing January 1, 2002, the price payable by El Paso for each MMBtu over and above the Monthly Base Quantity equaled the sum of (i) the Index Price and (ii) \$.02 per MMBtu, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to the same Gas

Purchase Agreement amendment, commencing January 1, 2003, the price for quantities up to and including the Monthly Base Quantity shall be the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to the same Gas Purchase Agreement amendment, commencing January 1, 2003, the price for quantities up to and including the Monthly Base Quantity shall be the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to the July 1, 2002 Gas Purchase Agreement amendment, effective January 1, 2003, the price payable by El Paso for each MMBtu of Gas produced up to and including the applicable monthly specified base quantity during each month shall be divided into two categories, a Fixed Price quantity and an Index Price Quantity. Until December 31, 2003, the price payable by El Paso for each MMBtu of Gas produced up to and including the applicable monthly Fixed Price Quantity shall be \$3.68 per MMBtu. The price payable by El Paso for each MMBtu of Gas produced in excess of the applicable monthly Fixed Price Quantity and up to and including the applicable monthly Index Price Quantity shall be the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Commencing January 1, 2004, the pricing formula for the Index Price Quantity described in the immediately preceding sentence shall apply to the entire monthly base quantity. Also effective January 1, 2004, the price payable by El Paso for Gas production in excess of the specified monthly base quantity each month shall be the sum of the Index Price and \$.02 per MMBtu, multiplied by 0.9826, the wet/dry conversion factor. Effective January 31, 2004, the Gas Purchase Agreement was terminated. Effective February 1, 2004, Gas will be sold on a month to month basis to various purchasers until such time as a long-term contract can be secured.

The Gas Purchase Agreement, and the amendments thereto, are filed as exhibits to this Form 10-K, and the foregoing summary of the material terms of such agreement is qualified in its entirety by reference to the terms of such agreement and amendments as set forth in such exhibits.

Operation of Properties

No Control by Trust. Under the terms of the Conveyance, neither the Trustees nor Unitholders will be able to influence or control the operation or future development of the Underlying Properties. Unitholders will therefore be reliant on the Company and the other working interest owners to make all decisions regarding operations on the Underlying Properties. The Trust will not be able to appoint or control the appointment of operators.

The Conveyance does not prohibit the transfer of the Underlying Properties by the Company, subject to and burdened by the Royalty Interests. The Company and the other working interest owners of the Underlying Properties will have the right, subject to certain restrictions, to abandon any well or lease on the Underlying Properties under certain circumstances. Upon abandonment of any such well or lease, that portion of the Royalty Interests relating thereto will be extinguished. See “—Sale and Abandonment of the Underlying Properties.”

Operating Agreement. Pursuant to the Operating Agreement, ConocoPhillips operated and maintained the Underlying Properties for the Company and the other working interest owners until January 1, 2003. As amended October 30, 1996, the Operating Agreement had a 3-year term and was to be automatically renewed for additional one-year periods unless either party provided written notice to the other party of its desire to terminate the Operating Agreement before the end of the current calendar year. On December 27, 2000, Dominion Resources notified ConocoPhillips that it was terminating the automatic one-year extension of the agreement. As such, the Operating Agreement was amended effective January 1, 2003 naming Dominion Black Warrior Basin, Inc. as the operator of the underlying properties.

Sale and Abandonment of Underlying Properties

The Company has the right to abandon any well or lease included in the Underlying Properties if, in its opinion, acting as would a reasonably prudent operator, such well or lease is not capable of

producing Gas in commercial quantities (determined before giving effect to the Royalty Interests). Neither the Trust nor the Unitholders will control the timing of the plugging and abandoning of any wells. Through December 31, 2003, none of the wells included in the Underlying Properties had been plugged and abandoned.

The Company may sell its interest in the Underlying Properties, subject to and burdened by the Royalty Interests, without the consent of the Trust or Unitholders. Under the Trust Agreement, the Company has certain rights (but not the obligation) to purchase the Royalty Interests upon termination of the Trust. See “Business—Description of the Trust Agreement—Termination and Liquidation of the Trust.”

Dominion Resources’s Assurances

Pursuant to the Trust Agreement, Dominion Resources has agreed to cause each of the following obligations to be paid in full when due: (i) all liabilities and operating and capital expenses that any Company Interests Owner becomes obligated to pay as a result of such Company Interests Owner’s obligations under the Conveyance and (ii) the obligations of the Company to indemnify the Trust, the Trustee and the Delaware Trustee for certain environmental liabilities under the Trust Agreement (collectively, the “Payment Obligations”).

The Trustee may, at any time after the 10th day following receipt by Dominion Resources of written notice from the Trustee that a Payment Obligation has not been paid when due, make demand of Dominion Resources for payment stating the amount due. Dominion Resources is obligated to cure any failure to pay the obligation within 10 days following receipt of the foregoing demand. After written request of the Unitholders owning of record not less than 25 percent of the Units then outstanding served upon the Trustee, and absent action by the Trustee within 10 days following receipt by the Trustee of such written request to enforce such obligations for the benefit of the Trust, such Unitholders may, acting as a single class and on behalf of the Trust, seek to enforce Dominion Resources’s performance obligations.

All of Dominion Resources’s obligations will terminate upon: (i) the termination and cancellation of the Trust, (ii) the sale or other transfer by the Company of all or substantially all of the Company’s interest in the Underlying Properties subject to the terms of the Trust Agreement and (iii) the sale or other transfer of a majority of Dominion Resources’s direct or indirect equity ownership interest in the Company; provided that, with respect to clauses (ii) and (iii) above, Dominion Resources’s obligations will terminate only if: (a) the transferee has a specified credit rating or the transferee together with an affiliate that guarantees the transferee’s obligations has not less than a specified net worth or (b) the transferee is approved by the holders of a majority of the outstanding Units; and provided further, that in the case of clauses (ii) or (iii) above the transferee also unconditionally agrees in writing, in form and substance reasonably satisfactory to the Trustee, to assume Dominion Resources’s remaining obligations under the Trust Agreement with respect to the assets transferred and under the Administrative Services Agreement.

Title to Properties

Alabama counsel to Dominion Resources and the Company has opined that the Company’s title to its interest in the Underlying Properties, and the Trust’s title to the Royalty Interests, are good and defensible in accordance with standards generally accepted in the natural gas industry, subject to such exceptions that, in the opinion of Alabama counsel, are not so material as to detract substantially from the use or value of the Company Interests or the Royalty Interests.

Although the matter is not entirely free from doubt, Alabama counsel has opined that the Royalty Interests constitute interests in real property under Alabama law. Consistent therewith, the Conveyance states that the Royalty Interests constitute real property interests. The Company has recorded the Conveyance in the appropriate real property records of Alabama in accordance with local recordation provisions. If, during the term of the Trust, the Company or any Company Interests Owner becomes

involved as a debtor in bankruptcy proceedings under the Federal Bankruptcy Code, it is not entirely clear that the Royalty Interests would be treated as real property interests under the laws of Alabama.

Item 3. Legal Proceedings.

There are no material pending legal proceedings to which the Trust is a party or of which any of its property is the subject.

Item 4. Submission of Matters to a Vote of Security Holders.

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters.

The Units in the Trust are listed and traded on the NYSE under the symbol "DOM." The following table sets forth, for the periods indicated, the high and low sales prices per Unit on the NYSE and the amount of quarterly cash distributions per Unit paid by the Trust.

	Price		Distribution per Unit
	High	Low	
2003			
First Quarter	\$24.25	\$20.10	\$.644817
Second Quarter	27.30	21.95	.695362
Third Quarter	29.18	23.05	.616863
Fourth Quarter	29.25	26.70	.572678
2002			
First Quarter	\$21.30	\$19.65	\$.576189
Second Quarter	24.55	17.20	.575137
Third Quarter	22.27	17.55	.623862
Fourth Quarter	22.00	19.05	.597635

At March 1, 2004, there were 7,850,000 Units outstanding and approximately 704 Unitholders of record.

The Trust has no equity compensation plans and has not repurchased any units during the period covered by this report.

Item 6. Selected Financial Data.

	Year Ended December 31,				
	2003	2002	2001	2000	1999
Royalty Income	\$20,746,843	\$19,418,476	\$25,937,254	\$20,874,519	\$20,031,958
Distributable Income	\$19,835,642	\$18,623,941	\$25,215,487	\$20,229,281	\$19,385,356
Distributable Income per Unit	\$ 2.53	\$ 2.37	\$ 3.21	\$ 2.58	\$ 2.47
Distributions per Unit	\$ 2.53	\$ 2.37	\$ 3.21	\$ 2.58	\$ 2.46
Total Assets, December 31	\$44,820,393	\$50,566,037	\$57,819,259	\$65,691,406	\$75,397,111
Total Corpus, December 31	\$44,689,580	\$50,441,689	\$57,707,439	\$65,575,056	\$75,273,180

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

The Trust collects the proceeds attributable to the Royalty Interests and makes quarterly cash distributions to Unitholders. The only assets of the Trust, other than cash and cash equivalents being held for the payment of expenses and liabilities and for distribution to Unitholders, are the Royalty Interests. The Royalty Interests owned by the Trust burden the interest in the Underlying Properties that is owned by the Company.

The Royalty Interests consist of overriding royalty interests burdening the Company's interest in the Underlying Properties. The Royalty Interests generally entitle the Trust to receive 65 percent of the Gross Proceeds (as defined below) during the preceding calendar quarter. The Royalty Interests are non-operating interests and bear only expenses related to property, production and related taxes (including severance taxes). Gross Proceeds consist generally of the aggregate amounts received by the Company attributable to the interests of the Company in the Underlying Properties from the sale of coal seam gas at the central delivery points in the gathering system for the Underlying Properties.

Distributable income of the Trust generally consists of the excess of royalty income plus interest income over the administrative expenses of the Trust. Upon receipt by the Trust, royalty income is invested in short-term investments in accordance with the Trust Agreement until its subsequent distribution to Unitholders.

The amount of distributable income of the Trust for any calendar year may differ from the amount of cash available for distribution to the Unitholders in such year due to differences in the treatment of the expenses of the Trust and the determination of those amounts. The financial statements of the Trust are prepared on a modified cash basis pursuant to which the expenses of the Trust are recognized when they are paid or reserves are established whereas royalty income is recognized when received by the Trust. Consequently, the reported distributable income of the Trust for any year is determined by deducting from the income received by the Trust the amount of expenses paid by the Trust during such year. The amount of cash available for distribution to Unitholders is determined after adjustment for changes in reserves for unpaid liabilities in accordance with the provisions of the Trust Agreement. See Note 5 to the financial statements of the Trust appearing elsewhere in this Form 10-K for additional information regarding the determination of the amount of cash available for distribution to Unitholders.

The year 2003 marked the ninth full year of the existence of the Trust. The Trust received royalty income amounting to \$20,746,843 during the year ended December 31, 2003, compared to \$19,418,476 for 2002 and \$25,937,254 for 2001. The royalty income received by the Trust was net of the Royalty Interests' allocable share of property, production and related taxes. Administrative expenses during the year ended December 31, 2003 increased to \$923,785, compared to \$810,557 for 2002 and \$776,431 for 2001. Distributable income for the year ended December 31, 2003 was \$19,835,642, or \$2.53 per Unit, compared to \$18,623,941, or \$2.37 per Unit, for 2002 and \$25,215,487, or \$3.21 per Unit, for 2001.

The increase in administrative expenses in 2003 compared to 2002 was primarily the result of increased professional fees. Similarly, the increase from 2001 to 2002 was the result of higher printing costs and increased professional fees.

Royalty income to the Trust is attributable to the sale of depleting assets. All of the Underlying Properties burdened by the Royalty Interests consist of producing properties. Accordingly, the proved reserves attributable to the Company's interest in the Underlying Properties are expected to decline substantially during the term of the Trust and a portion of each cash distribution made by the Trust will, therefore, be analogous to a return of capital. Accordingly, cash yields attributable to the Units are expected to decline over the term of the Trust. The decreases in royalty income and distributable income noted in the preceding paragraph were due primarily to this depletion of reserves and to a decrease in the average prices received for gas attributable to the Royalty Interests as summarized in the table below.

Royalty Income received by the Trust in a given calendar year will generally reflect the proceeds from the sale of gas produced from the Underlying Properties during the first three quarters of that year and the fourth quarter of the preceding calendar year due to the timing of the receipt of these revenues. Accordingly, the royalty income included in distributable income for the years ended December 31, 2003, 2002 and 2001, was based on production volumes and natural gas prices for the periods from October 1, 2002 to September 30, 2003, October 1, 2001 to September 30, 2002 and October 1, 2000 to September 30, 2001, respectively.

The following table sets forth the production volumes attributable to the Trust's Royalty Interests and the average sales Price and Index Price for such production for the periods indicated.

	For 12 Months Ended		
	2003	2002	2001
Production (Bcf) (1)	5.326	6.129	6.963
Production (MMBtu) (2)	5.367	6.152	6.942
Average Contract Price Received (\$/MMBtu)	\$ 4.13	\$ 3.36	\$ 3.76
Average Index Price (\$/MMBtu)	\$ 4.27	\$ 2.78	\$ 4.94

(1) Billion cubic feet of natural gas.

(2) Trillion British Thermal Units.

The information in this Form 10-K concerning production and prices relating to the Royalty Interests is based on information prepared and furnished by the Company to the Trustee. The Trustee has no control over and no responsibility relating to the operation of or accounting for the Underlying Properties.

El Paso (as successor to Sonat Marketing) was required under the Gas Purchase Agreement to purchase the Gas produced from the Underlying Properties for as long as reserves on the Underlying Properties until such agreement was terminated, effective January 31, 2004. Under the agreement, Sonat Marketing was, in past years, obligated to purchase up to a specified monthly base quantity of Gas (the "Index Price Quantity") for a contract price equal to the Index Price plus a specified premium (between \$.05 and \$.07 per MMBtu) over the Index Price. Until December 31, 1998, the Contract Price paid was subject to a minimum price of \$1.85 per MMBtu and a maximum price of \$2.63 per MMBtu. Beginning effective January 1, 1999, the Contract Price paid was subject to a minimum price of \$2.16 per MMBtu and a maximum price of \$3.07 per MMBtu. Beginning effective January 1, 2000 through December 31, 2000, the price paid on Index Price Quantities was subject to a minimum price of \$2.20 and a maximum price of \$2.82. Beginning effective January 1, 2001 through December 31, 2001, the Contract Price paid was subject to a minimum price of \$2.83 per MMBtu and a maximum price of \$6.46 per MMBtu. Beginning effective January 1, 2002 through December 31, 2002, the Contract Price paid was subject to a minimum price of \$3.70 per MMBtu and a maximum price of \$5.30 per MMBtu. Commencing January 1, 2003, the price for quantities up to and including the Monthly Base Quantity was the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to the same Gas Purchase Agreement amendment, commencing January 1, 2003, the price for quantities up to and including the Monthly Base Quantity was the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Pursuant to the July 1, 2002 Gas Purchase Agreement amendment, effective January 1, 2003, the price payable by El Paso for each MMBtu of gas produced up to and including the applicable monthly specified base quantity during each month was divided into two categories, a Fixed Price quantity and an Index Price Quantity. Until December 31, 2003, the price payable by El Paso for each MMBtu of gas produced up to and including the applicable monthly Fixed Price Quantity was \$3.68 per MMBtu. The price payable by El Paso for each MMBtu of gas produced in excess of the applicable monthly Fixed Price Quantity and up to and including the applicable monthly Index Price Quantity was the sum of (i) the Index Price and (ii) a premium per MMBtu, ranging from \$.05 to \$.07, multiplied by 0.9826, the wet/dry conversion factor. Commencing January 1, 2004, the pricing formula for the Index Price Quantity described in the immediately preceding sentence shall apply to the entire monthly base quantity. Also effective January 1, 2004, the price payable by El Paso for Gas production in excess of the specified monthly base quantity each month shall be the sum of the Index Price and \$.02 per MMBtu, multiplied by 0.9826, the wet/dry conversion factor. Prior to April 1, 1996, Sonat Marketing was obligated to purchase Gas production in excess of the specified monthly base quantities at the Index Price. Effective April 1, 1996 through December 31, 2001, the price paid for such Gas production in excess of the specified monthly basis quantities was the Index Price plus \$.02. The Index Price, which is determined on a monthly basis, was Southern Natural Gas Company's posted index

price for deliveries of gas in Louisiana. Effective January 31, 2004, the Gas Purchase Agreement was terminated. Effective February 1, 2004, Gas will be sold on a month to month basis to various purchasers until such time as a long-term contract can be secured.

The net proved reserves attributable to the Royalty Interests have been estimated as of December 31, 2003, 2002 and 2001, by independent petroleum engineers. The reserve quantities of 41.6 Bcf for 2003 compared to 42.6 Bcf for 2002 and compared to 51.0 Bcf for 2001, reflect a decline in reserves between 2001 and 2002 and between 2002 and 2003 as a result of production. See "Financial Statements and Supplementary Data—Notes to Financial Statements—Note 8."

Critical Accounting Policies and Estimates

The Trust's financial statements reflect the selection and application of accounting policies that require the Trust to make significant estimates and assumptions. The following are some of the more critical judgment areas in the application of accounting policies that currently affect the Trust's financial condition and results of operations.

1. New Accounting Pronouncements

Statement of Financial Accounting Standards ("SFAS") No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure, an amendment of FASB Statement No. 123," was issued in December 2002 and provides new transition methods if an entity adopts the fair value based method of valuing stock-based compensation suggested in SFAS No. 123, "Accounting for Stock-Based Compensation," as well as requiring additional disclosures in interim and annual financial statements. The Trust has no options or other stock-based instruments and accordingly, the impact of this new Standard was not material to the financial statements of the Trust.

SFAS No. 149, "Accounting for Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133," was issued in April 2003 and is effective for contracts entered into after June 20, 2003. The statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts. The Trust has no derivative instruments and accordingly, the impact of this new standard will not be material to the financial statements of the Trust.

SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," was issued in May 2003, and is effective for fiscal quarters beginning after June 15, 2003. The Trust has no Financial Instruments and accordingly, the impact of this new standard will not be material to the financial statements of the Trust.

Financial Accounting Standards Board ("FASB") Interpretation ("FIN") No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," requires disclosures beginning with financial statements ending after December 15, 2002, and requires liability recognition beginning January 1, 2003. The Trust had no such guarantees outstanding as of December 31, 2003.

FIN No. 46, "Consolidation of Variable Interest Entities," was issued in January 2003. This interpretation of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," applies immediately to variable interest entities created after January 31, 2003 and applies to the first period beginning after June 15, 2003, to entities acquired before February 1, 2003. This FIN does not affect the Trust as it has no unconsolidated subsidiaries accounted for under the equity method of accounting.

2. Basis of Accounting

The financial statements of the Trust are prepared on a modified cash basis and are not intended to present financial position and results of operations in conformity with United States Generally

Accepted Accounting Principles (“GAAP”). Preparation of the Trust’s financial statements on such basis includes the following:

- Royalty income and interest income are recorded in the period in which amounts are received by the Trust rather than in the month of production or when earned.
- General and administrative expenses are recorded based on liabilities paid and cash reserves established out of cash received.
- Amortization of the Royalty Interests is calculated on a unit-of-production basis and charged directly to Trust corpus based upon when revenue is received.
- Distributions to Unitholders are recorded when declared by the Trustee (see Note 5).

The financial statements of the Trust differ from financial statements prepared in accordance with GAAP because royalty income is not accrued in the period of production, general and administrative expenses recorded are based on liabilities paid and cash reserves established out of cash received (rather than on an accrual basis), and amortization of the Royalty Interests is not charged against operating results.

3. Impairment

The net amount of Royalty Interests in gas properties is limited to the sum of the future net cash flows attributable to the Trust’s gas reserves at year end using current unescalated product prices. If the net cost of Royalty Interests in gas properties exceeds the aggregate of these amounts, an impairment provision is recorded and charged to the Trust Corpus.

4. Revenue Recognition

Revenues from Royalty Interests are recognized in the period in which amounts are received by the Trust. Royalty income received by the Trust in a given calendar year will generally reflect the proceeds, on an entitlements basis, from natural gas produced for the twelve-month period ended September 30th in that calendar year.

5. Reserve Disclosure

Independent petroleum engineers estimate the net proved reserves attributable to the Royalty Interest. In accordance with SFAS No. 69, “Disclosures About Oil and Gas Producing Activities,” estimates of future net revenues from proved reserves have been prepared using year-end contractual gas prices and related costs. Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and the timing of development of non-producing reserves. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

6. Contingencies

Contingencies related to the Underlying Properties that are unfavorably resolved would generally be reflected by the Trust as reductions to future royalty income payments to the Trust with corresponding reductions to cash distributions to Unitholders. The Trustee is aware of no such items as of December 31, 2003.

Liquidity and Capital Resources

As stipulated in the Trust Agreement, the Trust is intended to be passive in nature and neither the Delaware Trustee nor the Trustee has any control over or any responsibility relating to the operation of the Underlying Properties. The Trustee has powers to collect and distribute proceeds received by the Trust and pay Trust liabilities and expenses and its actions have been limited to those activities. The

assets of the Trust are passive in nature, 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. As a result, other than such borrowings, if any, the Trust has no source of liquidity or capital resources other than the Royalty Interests. See the earlier discussions in Item 7 for the discussion of the operations and cash inflows and outflows of the Trust.

Off-Balance Sheet Arrangements

As stipulated in the Trust Agreement, the Trust is intended to be passive in nature and neither the Delaware Trustee nor the Trustee has any control over or any responsibility relating to the operation of the Underlying Properties. The Trustee has powers to collect and distribute proceeds received by the Trust and pay Trust liabilities and expenses and its actions have been limited to those activities. Therefore, the Trust has not engaged in any off-balance sheet arrangements.

Tabular Disclosure of Contractual Obligations

<u>Contractual Obligations</u>	<u>Total</u>	<u>Payments Due by Period</u>			
		<u>Less Than 1 Year</u>	<u>1-3 Years</u>	<u>3-5 Years</u>	<u>More Than 5 Years</u>
Distribution declared subsequent to year end..	\$4,466,474	\$4,466,474	0	0	0
Total	\$4,466,474	\$4,466,474	0	0	0

The above payable relates to distributions declared March 1, 2004 and payable March 10, 2004.

Forward-Looking Statements

This Annual Report includes "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934, which are intended to be covered by the safe harbor created thereby. All statements other than statements of historical fact included in this Annual Report are forward-looking statements. Such statements include, without limitation, factors affecting the price of oil and natural gas contained in Item 1, "Business," certain reserve information and other statements contained in Item 2, "Properties," and certain statements regarding the Trust's financial position, industry conditions and other matters contained in this Item 7. Although the Trustee believes that the expectations reflected in such forward-looking statements are reasonable, such expectations are subject to numerous risks and uncertainties and the Trustee can give no assurance that they will prove correct. There are many factors, none of which is within the Trustee's control, that may cause such expectations not to be realized, including, among other things, factors identified in this Annual Report affecting oil and gas prices and the recoverability of reserves, general economic conditions, actions and policies of petroleum-producing nations and other changes in the domestic and international energy markets.

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

The Trust invests in no derivative financial instruments and has no foreign operations or long-term debt instruments. The assets of the Trust are passive in nature, 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. The Trust periodically holds short-term investments acquired with funds held by the Trust pending distribution to Unitholders and funds held in reserve for the payment of Trust expenses and liabilities. Because of the short-term nature of these borrowings and investments and certain limitations upon the types of such investments that may be held by the Trust, the Trustee believes that the Trust is not subject to any material interest rate risk. The Trust does not engage in transactions in foreign currencies that could expose the Trust or Unitholders to any foreign currency related market risk.

Item 8. *Financial Statements and Supplementary Data.*

INDEPENDENT AUDITORS' REPORT

To Unitholders of Dominion Resources Black Warrior Trust and
Bank of America, N.A., Trustee

We have audited the accompanying statements of assets, liabilities and trust corpus of Dominion Resources Black Warrior Trust (the "Trust") as of December 31, 2003 and 2002, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

In our opinion, such financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of the Trust at December 31, 2003 and 2002, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2003, on the basis of accounting described in Note 2.

DELOITTE & TOUCHE LLP
Dallas, Texas
March 9, 2004

DOMINION RESOURCES BLACK WARRIOR TRUST
FINANCIAL STATEMENTS

Statements of Assets, Liabilities and Trust Corpus

	December 31,	
	2003	2002
ASSETS		
Cash and cash equivalents	\$ 87,026	\$ 103,220
Royalty interests in gas properties (less accumulated amortization of \$111,084,133 and \$105,354,683, respectively)	<u>44,733,367</u>	<u>50,462,817</u>
Total Assets	<u>\$44,820,393</u>	<u>\$50,566,037</u>
LIABILITIES AND TRUST CORPUS		
Trust expenses payable	\$ 130,813	\$ 124,348
Trust corpus (7,850,000 units of beneficial interest authorized, issued and outstanding)	<u>44,689,580</u>	<u>50,441,689</u>
Total Liabilities and Trust Corpus	<u>\$44,820,393</u>	<u>\$50,566,037</u>

Statements of Distributable Income

	Year Ended December 31,		
	2003	2002	2001
Royalty income	\$20,746,843	\$19,418,476	\$25,937,254
Interest income	<u>12,584</u>	<u>16,022</u>	<u>54,664</u>
	20,759,427	19,434,498	25,991,918
General and administrative expenses	<u>(923,785)</u>	<u>(810,557)</u>	<u>(776,431)</u>
Distributable income	<u>\$19,835,642</u>	<u>\$18,623,941</u>	<u>\$25,215,487</u>
Distributable income per unit (7,850,000 units)	<u>\$ 2.53</u>	<u>\$ 2.37</u>	<u>\$ 3.21</u>
Distributions per unit	<u>\$ 2.53</u>	<u>\$ 2.37</u>	<u>\$ 3.21</u>

Statements of Changes in Trust Corpus

	Year Ended December 31,		
	2003	2002	2001
Trust corpus, beginning of period	\$ 50,441,689	\$ 57,707,439	\$ 65,575,056
Amortization of royalty interests	<u>(5,729,450)</u>	<u>(7,263,029)</u>	<u>(7,887,390)</u>
Distributable income	19,835,642	18,623,941	25,215,487
Distributions to Unitholders	<u>(19,858,301)</u>	<u>(18,626,662)</u>	<u>(25,195,714)</u>
Trust corpus, end of period	<u>\$ 44,689,580</u>	<u>\$ 50,441,689</u>	<u>\$ 57,707,439</u>

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS
Years Ended December 31, 2003, 2002 and 2001

1. Trust Organization and Provisions

Dominion Resources Black Warrior Trust (the "Trust") was formed as a Delaware business trust pursuant to the terms of the Trust Agreement of Dominion Resources Black Warrior Trust (as amended, the "Trust Agreement"), entered into effective as of May 31, 1994, among Dominion Black Warrior Basin, Inc., an Alabama corporation (the "Company"), as trustor; Dominion Resources, Inc., a Virginia corporation ("Dominion Resources"); and Bank of America, N.A. (as successor to NationsBank of Texas, N.A.), a national banking association (the "Trustee"); and Mellon Bank (DE) National Association, a national banking association (the "Delaware Trustee"), as trustees. The Trustees are independent financial institutions.

The Trust is a grantor trust formed to acquire and hold certain overriding royalty interests (the "Royalty Interests") burdening proved natural gas properties located in the Pottsville coal formation of the Black Warrior Basin, Tuscaloosa County, Alabama (the "Underlying Properties") owned by the Company. The Trust was initially created by the filing of its Certificate of Trust with the Delaware Secretary of State on May 31, 1994. In accordance with the Trust Agreement, the Company contributed \$1,000 as the initial corpus of the Trust. On June 28, 1994, the Royalty Interests were conveyed to the Trust by the Company pursuant to the Overriding Royalty Conveyance (the "Conveyance"), effective as of June 1, 1994, from the Company to the Trust, in consideration for all the 7,850,000 authorized units of beneficial interest ("Units") in the Trust. The Company transferred all the Units to its parent, Dominion Energy, Inc., a Virginia corporation ("Dominion Energy"), which in turn transferred all the Units to its parent, Dominion Resources, Inc., a Virginia corporation ("Dominion Resources"), which sold an aggregate of 6,904,000 Units to the public through various underwriters (the "Underwriters") in June and August 1994 and the remaining 946,000 Units through certain of the Underwriters in June 1995.

All of the production attributable to the Underlying Properties is from the Pottsville coal formation and is coal seam gas that entitled the owners of such production to tax credits pursuant to Section 29 of the Internal Revenue Code of 1986, as amended (the "Code"), upon the production and sale of such gas before January 1, 2003, provided certain requirements were satisfied.

The Trustee has all powers to collect and distribute proceeds received by the Trust and to pay Trust liabilities and expenses. The Delaware Trustee has only such powers as are set forth in the Trust Agreement or are required by law and is not empowered to otherwise manage or take part in the management of the Trust. The Royalty Interests are passive in nature and neither the Trustee nor the Delaware Trustee has any control over, or any responsibility relating to, the operation of the Underlying Properties or the Company's interest therein.

The Trust is subject to termination under certain circumstances described in the Trust Agreement. Upon the termination of the Trust, all Trust assets will be sold and the net proceeds therefrom distributed to Unitholders.

The only assets of the Trust, other than cash and temporary investments being held for the payment of expenses and liabilities and for distribution to Unitholders, are the Royalty Interests. The Royalty Interests consist of overriding royalty interests burdening the Company's interest in the Underlying Properties. The Royalty Interests generally entitle the Trust to receive 65 percent of the Company's Gross Proceeds (as defined below). The Royalty Interests are non-operating interests and bear only expenses related to property, production and related taxes (including severance taxes). "Gross Proceeds" consist generally of the aggregate amounts received by the Company attributable to the interests of the Company in the Underlying Properties from the sale of coal seam gas at the central delivery points in the gathering system for the Underlying Properties. The definitions, formulas and accounting procedures and other terms governing the computation of the Royalty Interests are set forth in the Conveyance.

NOTES TO FINANCIAL STATEMENTS—(Continued)

Because of the passive nature of the Trust and the restrictions and limitations on the powers and activities of the Trustee contained in the Trust Agreement, the Trustee does not consider any of the officers and employees of the Trustee to be “officers” or “executive officers” of the Trust as such terms are defined under applicable rules and regulations adopted under the Securities Exchange Act of 1934.

2. Basis of Accounting

The financial statements of the Trust are prepared on a modified cash basis and are not intended to present financial position and results of operations in conformity with United States Generally Accepted Accounting Principles (“GAAP”). Preparation of the Trust’s financial statements on such basis includes the following:

- Royalty income and interest income are recorded in the period in which amounts are received by the Trust rather than in the month of production or when earned.
- General and administrative expenses are recorded based on liabilities paid and cash reserves established out of cash received.
- Amortization of the Royalty Interests is calculated on a unit-of-production basis and charged directly to trust corpus based upon when revenue is received.
- Distributions to Unitholders are recorded when declared by the Trustee (see Note 5).

The financial statements of the Trust differ from financial statements prepared in accordance with GAAP because royalty income is not accrued in the period of production, general and administrative expenses recorded are based on liabilities paid and cash reserves established out of cash received (rather than on an accrual basis), and amortization of the Royalty Interests is not charged against operating results.

Use of Estimates

The preparation of financial statements in conformity with the basis of accounting described above requires management to make estimates and assumptions that affect reported amounts of certain assets, liabilities, revenues and expenses as of and for the reporting periods. Actual results may differ from such estimates.

Impairment

Trust management routinely reviews its Royalty Interests in oil and gas properties for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If an impairment event occurs and it is determined that the carrying value of the Trust’s Royalty Interests may not be recoverable, an impairment will be recognized as measured by the amount by which the carrying amount of the Royalty Interests exceeds the fair value of these assets, which would likely be measured by discounting projected cash flows.

Distributable Income Per Unit

Basic earnings per share is computed by dividing net income by the weighted average shares outstanding. Earnings per share assuming dilution is computed by dividing net income by the weighted average number of shares and equivalent shares outstanding. The Trust had no equivalent shares outstanding for any period presented, thus basic diluted earnings per unit and distributable income per unit are the same.

NOTES TO FINANCIAL STATEMENTS—(Continued)

New Accounting Pronouncements

SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure, an amendment of FASB Statement No. 123," was issued in December 2002 and provides new transition methods if an entity adopts the fair value based method of valuing stock-based compensation suggested in SFAS No. 123, "Accounting for Stock-Based Compensation," as well as requiring additional disclosures in interim and annual financial statements. The Trust has no options or other stock-based instruments and accordingly, the impact of this new Standard was not material to the financial statements of the Trust.

SFAS No. 149, "Accounting for Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133," was issued in April 2003 and is effective for contracts entered into after June 20, 2003. The statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts. The Trust has no derivative instruments and accordingly, the impact of this new standard will not be material to the financial statements of the Trust.

SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," was issued in May 2003, and is effective for fiscal quarters beginning after June 15, 2003. The Trust has no Financial Instruments and accordingly, the impact of this new standard will not be material to the financial statements of the Trust.

FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," requires disclosures beginning with financial statements ending after December 15, 2002, and requires liability recognition beginning January 1, 2003. The Trust had no such guarantees outstanding as of December 31, 2003.

FIN No. 46, "Consolidation of Variable Interest Entities," was issued in January 2003. This interpretation of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," applies immediately to variable interest entities created after January 31, 2003, and applies to the first period beginning after June 15, 2003, to entities acquired before February 1, 2003. This FIN does not affect the Trust as it has no unconsolidated subsidiaries accounted for under the equity method of accounting.

3. Federal Income Taxes

The Trust is a grantor trust for Federal income tax purposes. As a grantor trust, the Trust will not be required to pay Federal or state income taxes. Accordingly, no provision for income taxes has been made in these financial statements.

Because the Trust will be treated as a grantor trust, and because a Unitholder will be treated as directly owning an interest in the Royalty Interests, each Unitholder will be taxed directly on his per Unit pro rata share of income attributable to the Royalty Interests consistent with the Unitholder's method of accounting and without regard to the taxable year or accounting method employed by the Trust.

Production from coal seam gas wells drilled after December 31, 1979 and prior to January 1, 1993, qualified for the Federal income tax credit for producing nonconventional fuels under Section 29 of the Code. This tax credit was calculated annually based on each year's qualified production, and Dominion Resources provided the Trustee with Section 29 tax credit information related to the Underlying Properties. Coal seam gas produced and sold after December 31, 2002, will no longer generate a Section 29 tax credit unless the Section 29 tax credit is extended or reinstated by Congress. Legislation currently proposed to extend the Section 29 tax credit does not apply to coal seam gas attributable to the Underlying Properties.

NOTES TO FINANCIAL STATEMENTS—(Continued)

The Section 29 tax credit may be available to Unitholders with respect to the first quarter of 2003 because, among other reasons, it is attributable to coal seam gas produced and sold on or before December 31, 2002. The Trustee is seeking a private letter ruling from the Internal Revenue Service (“IRS”) on this issue. The estimated Section 29 tax credit, if allowed on such distributions, equals \$0.20 per Unit.

The Section 29 tax credit is based on the Unitholder’s pro rata share of qualifying production. It can be used only to the extent that a Unitholder’s regular tax liability exceeds the Unitholder’s tentative minimum tax liability after the regular tax liability has been reduced by the foreign tax credit and certain nonrefundable personal credits. Any part of the Section 29 tax credit not allowed for the tax year solely because of this alternative minimum tax limitation is subject to certain carryover provisions relating to the alternative minimum tax calculation. Except for the foregoing, there are no Code provisions that allow for the carryback or carryforward of Section 29 tax credits in any other circumstances. As the carryforward of unused Section 29 tax credits is related to the alternative minimum tax calculation for succeeding years, carryforwards should be allowed even if the Section 29 tax credit is not extended or reinstated after 2002.

In 1997, the Tax Court upheld the IRS position that nonconventional fuel such as coal seam gas does not qualify for the Section 29 tax credit unless the producer received a formal certification from the Federal Energy Regulatory Commission (“FERC”). FERC’s certification authority expired effective January 1, 1993. During March 1999, the U.S. Court of Appeals for the 10th Circuit affirmed that decision. The appeal (which is not binding as precedent) suggests that lack of a certification from FERC may render the Section 29 tax credit unavailable in respect of production from wells recompleted in a qualified formation after January 1, 1993, the date that FERC’s certification authority expired (so that obtaining the requisite determination of any such well was impossible). Many producers believe that wells meeting the certification requirements are eligible for the Section 29 tax credit regardless of FERC certification. However, this position is not in accordance with the IRS position, the decision of the Tax Court or the decision of the U.S. Court of Appeals.

On December 23, 1999, a petition was filed with FERC by a coalition of energy producers seeking reinstatement of the certification process. FERC issued a Final Rule on July 14, 2000, amending its regulations to reinstate provisions for well category determinations under section 503 of the Natural Gas Policy Act (“NGPA”) of 1978 for Section 29 tax credits. The Final Rule extended the provisions to all wells spudded before January 1, 1993, and recompletions both before and after that date that qualify for the Section 29 tax credit. The Final Rule also provided for the designation of new tight formations. The Final Rule became effective on September 25, 2000.

During 2002, Dominion Resources initiated a review of all recompletion activity on the Underlying Properties since 1992 and caused applications for NGPA determinations for 383 wells to be filed with the Alabama Oil and Gas Board (the “Board”) on April 29, 2002. A formal hearing by the Board was held on May 29, 2002. At that hearing, affirmative notices for 75 of the 383 wells were issued. A second hearing was held on July 10, 2002, which favorably adjudicated the remaining 308 wells. Applications were timely filed with FERC and barring timely filed objections, the applications are accepted as final 45 days after receipt. To the best of Dominion Resource’s knowledge, no objections were filed to these applications. The ability of the Unitholders to utilize Section 29 tax credits (to the extent the Section 29 tax credit is available) could be in question during any time period a well was not certified, although arguments exist for retroactive application and for allowance of the Section 29 tax credits without certification.

Each Unitholder should consult his tax advisor regarding Trust tax compliance matters.

NOTES TO FINANCIAL STATEMENTS—(Continued)

4. Related Party Transactions

Dominion Resources provides accounting, bookkeeping and informational services to the Trust in accordance with an Administrative Services Agreement dated effective June 1, 1994. During 2003 this fee was \$388,582 and will increase annually by three percent. Aggregate fees paid by the Trust to Dominion Resources in 2003, 2002 and 2001 were \$388,582, \$380,031 and \$373,552, respectively.

Aggregate fees and expense reimbursements paid by the Trust to the Trustees in 2003, 2002, and 2001 were \$43,852, \$43,003 and \$42,355, respectively.

5. Distributions to Unitholders

The Trustee determines for each calendar quarter the amount of cash available for distribution to Unitholders. Such amount (the "Quarterly Distribution Amount") is an amount equal to the excess, if any, of the cash received by the Trust attributable to production from the Royalty Interests during such quarter, provided that such cash is received by the Trust on or before the last business day prior to the 45th day following the end of such calendar quarter, plus the amount of interest expected by the Trustee to be earned on such cash proceeds during the period between the date of receipt by the Trust of such cash proceeds and the date of payment to the Unitholders of such Quarterly Distribution Amount, plus all other cash receipts of the Trust during such quarter (to the extent not distributed or held for future distribution as a Special Distribution Amount (as defined below) or included in the previous Quarterly Distribution Amount) (which might include sales proceeds not sufficient in amount to qualify for a special distribution as described in the next paragraph), over the liabilities of the Trust paid during such quarter and not taken into account in determining a prior Quarterly Distribution Amount, subject to adjustments for changes made by the Trustee during such quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. An amount that is not included in the Quarterly Distribution Amount for a calendar quarter because such amount is received by the Trust after the last business day prior to the 45th day following the end of such calendar quarter will be included in the Quarterly Distribution Amount for the next calendar quarter. The Quarterly Distribution Amount for each quarter will be payable to Unitholders of record on the 60th day following the end of such calendar quarter unless such day is not a business day in which case the record date is the next business day thereafter. The Trustee will distribute the Quarterly Distribution Amount for each quarter on or prior to 70 days after the end of such calendar quarter to each person who was a Unitholder of record on the record date for such calendar quarter.

The Royalty Interests may be sold under certain circumstances and will be sold following termination of the Trust. A special distribution will be made of undistributed net sales proceeds and other amounts received by the Trust aggregating in excess of \$10 million (a "Special Distribution Amount"). The record date for a Special Distribution Amount will be the 15th day following the receipt by the Trust of amounts aggregating a Special Distribution Amount (unless such day is not a business day, in which case the record date will be the next business day thereafter) unless such day is within 10 days or less prior to the record date for a Quarterly Distribution Amount, in which case the record date for the Special Distribution Amount will be the same as the record date for the Quarterly Distribution Amount. Distribution to Unitholders of a Special Distribution Amount will be made no later than 15 days after the Special Distribution Amount record date.

6. Subsequent Events

Subsequent to December 31, 2003, the Trust declared and paid the following distribution:

<u>Quarterly Record Date</u>	<u>Payment Date</u>	<u>Distribution Per Unit</u>
March 1, 2004	March 10, 2004	\$.568977

NOTES TO FINANCIAL STATEMENTS—(Continued)

7. Quarterly Financial Data (Unaudited)

The following table sets forth the royalty income, distributable income and distributable income per Unit of the Trust for each quarter in the years ended December 31, 2003 and 2002 (in thousands, except per Unit amounts):

<u>Calendar Quarter</u>	<u>Royalty Income</u>	<u>Distributable Income</u>	<u>Distributable Income Per Unit</u>
2003			
First	\$ 5,229	\$ 4,950	\$.63
Second	5,707	5,498	.70
Third	5,094	4,850	.62
Fourth	4,717	4,538	.58
	<u>\$20,747</u>	<u>\$19,836</u>	<u>\$2.53</u>
2002			
First	\$ 4,659	\$ 4,441	\$.58
Second	4,752	4,558	.58
Third	5,122	4,904	.62
Fourth	4,885	4,721	.59
	<u>\$19,418</u>	<u>\$18,624</u>	<u>\$2.37</u>

Selected 2003 fourth quarter data are as follows (in thousands, except per Unit amounts):

Royalty income	\$4,717
Interest income	2
General and administrative expenses	(181)
Distributable income	<u>\$4,538</u>
Distributable income per Unit	<u>\$.58</u>
Distributions per Unit	<u>\$.58</u>

Due to significant revisions in estimate of reserve quantities (see Note 8), estimated amortization of royalty interests decreased by approximately \$0.1 million, increased by approximately \$0.1 million and decreased by approximately \$0.1 million during the fourth quarters of 2003, 2002 and 2001, respectively. These adjustments did not have an impact on the Trust's distributable income.

8. Supplemental Gas Disclosure (Unaudited)

The net proved reserves attributable to the Royalty Interests have been estimated as of December 31, 2003, 2002, 2001, and January 1, 2001, by independent petroleum engineers.

In accordance with Statement of Financial Accounting Standards No. 69, estimates of proved reserves and future net cash flows from proved reserves have been prepared using contractually guaranteed prices and end-of-period natural gas prices, and related costs. The standardized measure of future net cash flows from the gas reserves is calculated based on discounting such future net cash flows at an annual rate of 10 percent. The prices for December 31, 2003, 2002, and January 1, 2002, were \$5.89, \$4.10 and \$2.63 per Mcf, respectively, including the effect of the Gas Purchase Agreement (see Note 9). As of February 17, 2004, published Gas prices were approximately \$5.66 per Mcf. The use of such price as compared to \$5.42 per Mcf, which was used to calculate the above information, would result in a larger standardized measure of discounted future net cash flows for Gas.

Numerous uncertainties are inherent in estimating volumes and value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are

NOTES TO FINANCIAL STATEMENTS—(Continued)

subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the original estimates.

The reserve estimates for the Royalty Interests are based on a percentage share of the Company's Gross Proceeds payable to the Trust of 65 percent.

Proved developed reserves at January 1, 2001	56,768
Revisions of previous estimates	897
Production	<u>(6,701)</u>
Proved developed reserves at December 31, 2001	50,964
Revisions of previous estimates	(2,422)
Production	<u>(5,957)</u>
Proved developed reserves at December 31, 2002	42,585
Revisions of previous estimates	4,138
Production	<u>(5,137)</u>
Proved developed reserves at December 31, 2003	<u>41,586</u>

All proved reserve estimates presented above at December 31, 2003, 2002, 2001, and January 1, 2001, are proved developed.

Proved developed reserves, all located in the United States, for the Trust's Interests are estimated quantities of coal seam gas that geological and engineering data indicate with reasonable certainty to be recoverable in future years from the coal formation under existing economic and operating conditions. The Trusts's proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Estimated economic quantities were determined considering the Section 29 tax credits until December 31, 2002. As discussed in Note 3, coal seam gas produced and sold after December 31, 2002, will no longer generate a Section 29 tax credit unless the Section 29 tax credit is extended or reinstated by Congress.

The following table sets forth the standardized measure of discounted estimated future net cash flows from proved reserves at December 31, 2003, 2002 and 2001 relating to the Trust's Royalty Interests (thousands of dollars):

	<u>2003</u>	<u>2002</u>	<u>2001</u>
Future cash inflows	\$225,561	\$174,543	\$141,190
Future taxes	(13,534)	(10,473)	(6,712)
Future net cash flows	212,027	164,070	134,478
10% annual discount for estimated timing of cash flow ...	(94,743)	(68,507)	(49,234)
Standardized measure of discounted future net cash flows	<u>\$117,284</u>	<u>\$ 95,563</u>	<u>\$ 85,244</u>

Future cash flows do not include Section 29 tax credits, which no longer apply for coal seam gas produced and sold after December 31, 2002, as discussed in Note 3.

NOTES TO FINANCIAL STATEMENTS—(Continued)

The following table sets forth the changes in the present value of estimated future net cash flows from proved reserves during the period ended December 31, 2003, 2002 and 2001 (thousands of dollars):

	2003	2002	2001
Balance at beginning of period	\$ 95,563	\$ 85,244	\$ 271,050
Increase (decrease) due to:			
Royalty income, net of taxes	(20,269)	(19,988)	(25,515)
Changes in prices	30,434	48,600	(260,906)
Changes in estimated volumes	2,000	(26,817)	73,510
Accretion of discount	9,556	8,524	27,105
Balance at December 31	\$117,284	\$ 95,563	\$ 85,244

9. Gas Purchase Agreement

El Paso Merchant Energy—Gas, L.P. (“El Paso”) , as successor to Sonat Marketing Company (“Sonat Marketing”) was required under a gas purchase agreement to purchase the gas produced from the Underlying Properties until such agreement was terminated, effective January 31, 2004. Under the agreement, Sonat Marketing was, in past years, obligated to purchase up to a specified monthly base quantity (the “Index Price Quantity”) of gas for a contract price equal to the Index Price plus a specified premium (between \$.05 and \$.07 per MMBtu) over the Index Price. Until December 31, 1998, the Contract Price paid was subject to a minimum price of \$1.85 per MMBtu and a maximum price of \$2.63 per MMBtu. Beginning effective January 1, 1999, the Contract Price paid was subject to a minimum price of \$2.16 per MMBtu and a maximum price of \$3.07 per MMBtu. Beginning effective January 1, 2000 through December 31, 2000, the price paid on Index Price Quantities was subject to a minimum price of \$2.20 and a maximum price of \$2.82. Beginning effective January 1, 2001 through December 31, 2001, the Contract Price paid was subject to a minimum price of \$3.00 per MMBtu and a maximum price of \$5.30 per MMBtu. Beginning effective January 1, 2002 through December 31, 2002, the Contract Price paid was subject to a minimum price of \$3.80 per MMBtu and a maximum price of \$5.30 per MMBtu. Until December 31, 2003, the price payable by El Paso for each MMBtu of Gas produced up to and including the applicable monthly Fixed Price Quantity shall be \$3.68 per MMBtu. Prior to April 1, 1996, Sonat Marketing was obligated to purchase gas production in excess of the specified monthly base quantities at the Index Price. Effective April 1, 1996 through December 31, 2001, the price paid for such gas production in excess of the specified monthly basis quantities was the Index Price plus \$.02. The “Index Price,” which is determined on a monthly basis, was Southern Natural Gas Company’s posted index price for deliveries of gas in Louisiana. Effective February 1, 2004, Gas will be sold on a month to month basis to various purchasers until such time as a long-term contract can be secured.

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

None.

Item 9A. *Controls and Procedures.*

As of the end of the period covered by this report, the Trustee carried out an evaluation of the effectiveness of the design and operation of the Trust's disclosure controls and procedures pursuant to Exchange Act Rules 13a-15 and 15d-15. Based upon that evaluation, the Trustee concluded that the Trust's disclosure controls and procedures are effective in timely alerting the Trustee to material information relating to the Trust required to be included in the Trust's periodic filings with the Securities and Exchange Commission. In its evaluation of disclosure controls and procedures, the Trustee has relied, to the extent considered reasonable, on information provided by the Company. There has not been any change in the Trust's internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting.

PART III

Item 10. Directors and Executive Officers of the Registrant.

Directors and Executive Officers. The Trust has no directors or executive officers. Each of the Trustee and the Delaware Trustee is a corporate trustee that may be removed as trustee under the Trust Agreement, with or without cause, at a meeting duly called and held by the affirmative vote of Unitholders of not less than a majority of all the Units then outstanding. Any such removal of the Delaware Trustee shall be effective only at such time as a successor Delaware Trustee fulfilling the requirements of Section 3807(a) of the Delaware Code has been appointed and has accepted such appointment, and any such removal of the Trustee shall be effective only at such time as a successor Trustee has been appointed and has accepted such appointment.

Audit Committee and Nominating Committee. Because the Trust has no directors, it does not have an audit committee, an audit committee financial expert or a nominating committee.

Compliance with Section 16(a) of the Exchange Act. The Trust has no directors and officers and knows of no Unitholder that is a beneficial owner of more than 10 percent of the outstanding Units and is therefore unaware of any person that failed to report on a timely basis reports required by Section 16(a) of the Exchange Act.

Code of Ethics. Because the Trust has no employees, it does not have a code of ethics. Employees of the Trustee, Bank of America, N.A., must comply with the bank's code of ethics, a copy of which will be provided to Unitholders, without charge, upon request made to Bank of America, N.A., Trustee, 901 Main Street, 17th Floor, Dallas, Texas 75202, Attention: Ron Hooper.

Item 11. Executive Compensation.

The following is a description of certain fees and expenses anticipated to be paid or borne by the Trust, including fees expected to be paid to Dominion Resources, the Trustee, the Delaware Trustee, Mellon Investor Service, L.L.C. (as successor to Chemical Shareholder Services Group, Inc.) (the "Transfer Agent") or their respective affiliates.

Ongoing Administrative Expenses. The Trust is responsible for paying all fees, charges, expenses, disbursements and other costs incurred by the Trustee in connection with the discharge of its duties pursuant to the Trust Agreement, including, without limitation, trustee fees, engineering, audit, accounting and legal fees and expenses, printing and mailing costs, amounts reimbursed or paid to the Company or Dominion Resources pursuant to the Trust Agreement or the Administrative Services Agreement and the out-of-pocket expenses of the Transfer Agent.

Compensation of the Trustee. The Trust Agreement provides that the Trustee is to be compensated for its administrative services and preparation of quarterly and annual statements, out of the Trust assets, in an annual amount of \$28,858, plus an hourly charge for services in excess of a combined total of 350 hours annually at its standard rate, which is currently \$125 per hour. These service fees escalate by three percent annually. The Delaware Trustee is compensated for its administrative services, in an annual amount of \$5,000, which will be paid by the Trustee. Each of the Trustee and the Delaware Trustee is entitled to reimbursement for out-of-pocket expenses. Upon termination of the Trust, the Trustee will receive, in addition to its out-of-pocket expenses, a termination fee in the amount of \$10,000. If the Trustee resigns and a successor has not been appointed in accordance with the terms of the Trust Agreement within 210 days after the notice of resignation is received, the fee payable to the Trustee will increase significantly until a new trustee is appointed. During 2003, the Trustee and the Delaware Trustee received total compensation of \$38,858 and \$5,000, respectively.

Compensation of the Transfer Agent. The Transfer Agent receives a transfer agency fee of \$3.25 annually per account, plus \$1.50 for each certificate issued and \$.40 for each check issued (subject to an annual minimum of \$7,200).

Fees to Dominion Resources. Dominion Resources will receive throughout the term of the Trust an administrative services fee for accounting, bookkeeping and other administrative services relating to the Royalty Interests and the Underlying Properties as described in Item 13 under “Administrative Services Agreement.”

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

Security Ownership of Certain Beneficial Owners. The Trustee knows of no Unitholder that is a beneficial owner of more than five percent of the outstanding Units.

Security Ownership of Management. The Trust has no directors or executive officers. As of March 1, 2004, neither Bank of America, N.A., the Trustee, nor Mellon Bank (DE) National Association, the Delaware Trustee, beneficially owned any Units.

Changes in Control. The Trustee knows of no arrangements the operation of which may at a subsequent date result in a change in control of the Registrant.

Item 13. *Certain Relationships and Related Transactions.*

Administrative Services Agreement

Pursuant to the Trust Agreement, Dominion Resources and the Trust entered into the Administrative Services Agreement, pursuant to which the Trust is obligated, throughout the term of the Trust, to pay to Dominion Resources each quarter an administrative services fee for accounting, bookkeeping and other administrative services relating to the Royalty Interests and the Underlying Properties. The annual fee, payable in equal quarterly installments, is currently \$38,852 and will increase annually by three percent.

A copy of the Administrative Services Agreement is filed as an exhibit to this Form 10-K. The foregoing summary of the material provisions of the Administrative Services Agreement does not purport to be complete and is subject to, and is qualified in its entirety by reference to, all the provisions of the Administrative Services Agreement.

Dominion Resources’s Conditional Right of Repurchase

Dominion Resources retains in the Trust Agreement the right to repurchase all (but not less than all) outstanding Units at any time at which 15 percent or less of the outstanding Units is owned by persons or entities other than Dominion Resources and its affiliates. Any such repurchase would generally be at a price equal to the greater of (i) the highest price at which Dominion Resources or any of its affiliates acquired Units during the 90 days immediately preceding the Determination Date and (ii) the average closing price of Units on the NYSE for the 30 trading days immediately preceding the Determination Date. Any such repurchase would be conducted in accordance with applicable Federal and state securities laws. See “Business—Description of the Trust—Conditional Right of Repurchase.”

Potential Conflicts of Interest

The interests of Dominion Resources and its affiliates and the interests of the Trust and the Unitholders with respect to the Underlying Properties could at times be different. The following is a summary of certain conflicts of interest:

Obligations of Company Interests Owner may exceed its share of distributions and tax credits. As a working interest owner in the Underlying Properties, the Company Interests Owner is responsible for an average of approximately 98 percent of the operating costs of the Existing Wells but only entitled to approximately 28 percent of the revenues therefrom, after giving effect to the Royalty Interests. Based on the Reserve Estimate, beginning in the year 2000, the projected operating costs to be borne by the Company Interests Owner were anticipated to exceed its projected share of Gross Proceeds and Section 29 tax credits (to the extent the Section 29 tax credit is available and not expired). The terms of

the Conveyance provide, however, that the Company Interests Owner will make decisions with respect to the Company Interests pursuant to the standard of a reasonably prudent operator.

Sale or abandonment of Underlying Properties may terminate assurances. The Company Interests Owner's interests may conflict with those of the Trust and Unitholders in situations involving the sale or abandonment of Underlying Properties. The Company Interests Owner has the right at any time to sell any of the Underlying Properties subject to the Royalty Interests and may abandon a well or lease included in the Underlying Properties if such well or lease is not capable of producing in commercial quantities, determined before giving effect to the Royalty Interests. Under certain circumstances, a sale or abandonment will effectively terminate Dominion Resources's assurances of the Company Interests Owner's obligation to the Trust with respect to the Underlying Properties sold or abandoned. Such sales or abandonment may not be in the best interest of the Trust or the Unitholders.

Dominion Resources may profit from contracts with the Trust. The amount that Dominion Resources may charge for services it renders under the Administrative Services Agreement is established in such contract at rates that do not necessarily take into account the actual cost of rendering such services by Dominion Resources. Accordingly, Dominion Resources may profit or suffer losses in connection with the performance of such contract.

Item 14. *Principal Accounting Fees and Services.*

Fees for services performed by Deloitte & Touche LLP for the years ended December 31, 2003 and 2002 are:

	<u>2003</u>	<u>2002</u>
Audit Fees	\$79,000	\$74,500
Audit-related fees	—	—
Tax fees	—	—
All other fees	7,500	—
	<u>\$86,500</u>	<u>\$74,500</u>

As referenced in Item 10 above, the Trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to Deloitte & Touche LLP.

PART IV

Item 15. *Exhibits, Financial Statement Schedules and Reports on Form 8-K.*

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

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

Independent Auditors' Report

Statements of Assets, Liabilities and Trust Corpus as of December 31, 2003 and 2002

Statements of Distributable Income for the years ended December 31, 2003, 2002 and 2001

Statements of Changes in Trust Corpus for the years ended December 31, 2003, 2002 and 2001

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 included in the financial statements and notes thereto.

3. Exhibits

<u>Exhibit Number</u>	<u>Exhibit</u>
3.1	— Trust Agreement of Dominion Resources Black Warrior Trust dated as of May 31, 1994, by and among Dominion Black Warrior Basin, Inc., Dominion Resources, Inc., Mellon Bank (DE) National Association and NationsBank, N.A. (as successor to NationsBank of Texas, N.A.) (filed as Exhibit 3.1 to Dominion Resources, Inc.'s Registration Statement* on Form S-3 (No. 33-53513), and incorporated herein by reference).
3.2	— First Amendment of Trust Agreement of Dominion Resources Black Warrior Trust dated as of June 27, 1994, by and among Dominion Black Warrior Basin, Inc., Dominion Resources, Inc., Mellon Bank (DE) National Association and NationsBank, N.A. (as successor to NationsBank of Texas, N.A.) (filed as Exhibit 3.2 to the Registrant's Form 10-Q for the quarter ended June 30, 1994 and incorporated herein by reference).
10.1	— Overriding Royalty Conveyance dated as of June 28, 1994, from Dominion Black Warrior Basin, Inc. to Dominion Resources Black Warrior Trust (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended June 30, 1994 and incorporated herein by reference).
10.2	— Administrative Services Agreement dated as of June 1, 1994, by and between Dominion Resources, Inc. and Dominion Resources Black Warrior Trust (filed as Exhibit 10.2 to the Registrant's Form 10-Q for the quarter ended June 30, 1994 and incorporated herein by reference).
10.3	— Amendment to and Ratification of Overriding Royalty Conveyance dated as of November 20, 1994, among Dominion Black Warrior Basin, Inc., NationsBank, N.A. (as successor to NationsBank of Texas, N.A.), and Mellon Bank (DE) National Association (filed as Exhibit 10.3 to the Registrant's Form 10-K for the year ended December 31, 1994 and incorporated herein by reference).
10.4	— Gas Purchase Agreement, dated as of May 3, 1994, between Sonat Marketing and the Company (filed as Exhibit 10.2 to Dominion Resources, Inc.'s Registration Statement* on Form S-3 (No. 33-53513), and incorporated herein by reference).
10.5	— Amendment to Gas Purchase Agreement dated May 16, 1996, between Sonat Marketing and the Company (filed as Exhibit 10.1 to the Registrant's Form 10-Q for the quarter ended June 30, 1996 and incorporated herein by reference).
10.6	— Amendment to Gas Purchase Agreement dated April 9, 1998, between Sonat Marketing and the Company (filed as Exhibit 10.6 to the Registrant's Form 10-K for the year ended December 31, 1998 and incorporated herein by reference).
10.7	— Amendment to Gas Purchase Agreement dated July 1, 1999, between Sonat Marketing and the Company (filed as Exhibit 10.7 to the Registrant's Form 10-K for the year ended December 31, 1999 and incorporated herein by reference).
10.8	— Amendment to Gas Purchase Agreement dated July 1, 2000, between El Paso Merchant Energy-Gas, L.P., as successor to Sonat Marketing Company, and the Company (filed as an exhibit to the Registrant's Form 10-Q for the quarter ended September 30, 2000 and incorporated herein by reference).
10.9	— Amendment to Gas Purchase Agreement dated July 1, 2001, between El Paso Merchant Energy-Gas, L.P., as successor to Sonat Marketing Company, and the Company (filed as an exhibit to the Registrant's Form 10-Q for the quarter ended September 30, 2001 and incorporated herein by reference).
10.10	— Amendment to Gas Purchase Agreement dated July 1, 2002 between El Paso Merchant Energy-Gas, L.P., as successor to Sonat Marketing Company, and the Company (filed as an exhibit to the Registrant's Form 10-Q for the quarter ended September 30, 2002 and incorporated herein by reference).
23.1	— Consent of Ralph E. Davis Associates, Inc., independent petroleum engineers.
31.1	— Certification required by Rule 13a-14(a)/15d-14(a).
32.1	— Certification required by Rule 13a-14(b)/15d-14(b) and Section 906 of the Sarbanes Oxley Act of 2002.

Exhibit
Number

Exhibit

99.2 — Summary of Reserve Report, dated February 11, 2004, on the estimated reserves, estimated future net revenues and the discounted estimated future net revenues attributable to the Royalty Interests as of January 1, 2004, prepared by Ralph E. Davis & Associates Petroleum Engineers, independent petroleum engineers.

* On its own behalf and as sponsor of the Dominion Resources Black Warrior Trust

(b) *Reports on Form 8-K.*

No report on Form 8-K was filed by the Registrant during the last quarter of the period covered by this report. A report on Form 8-K was furnished by the Registrant on November 26, 2003, pursuant to Item 12 of Form 8-K announcing the Trust's quarterly distribution.

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.

DOMINION RESOURCES BLACK WARRIOR TRUST

By: BANK OF AMERICA, N.A., TRUSTEE

By: /s/ RON E. HOOPER
Ron E. Hooper
Senior Vice President and Administrator

Date: March 11, 2004

(The Registrant has no directors or executive officers.)