NATURAL RESOURCE PARTNERS LP
Form 10-K/A
March 03, 2010

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

Form 10-K/A

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the fiscal year ended December 31, 2009 or**
o	**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934** **For the transition period from to**

Commission file number: 1-31465
NATURAL RESOURCE PARTNERS L.P.
(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	**35-2164875** *(I.R.S. Employer Identification Number)*
601 Jefferson, Suite 3600 **Houston, Texas** *(Address of principal executive offices)*	**77002** *(Zip Code)*

(713) 751-7507
(Registrant s Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name Of Each Exchange On Which Registered
Common Units representing limited partnership interests	New York Stock Exchange

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

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

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

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 the filing requirements for the past 90 days. Yes þ No o

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

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 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. o

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

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

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

The aggregate market value of the Common Units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the Common Units outstanding, for this purpose, as if they were affiliates of the registrant) was approximately $0.8 billion on June 30, 2009 based on a price of $21.01 per unit, which was the closing price of the Common Units as reported on the daily composite list for transactions on the New York Stock Exchange on that date.

As of March 3, 2010, there were 69,451,136 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE.
None.

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EXPLANATORY NOTE

This Form 10-K/A for the year ended December 31, 2009 is being filed solely to correct the contractual obligations table on page 46 of the Form 10-K that was initially filed on February 26, 2009 (the Original Filing). The numbers in the contractual obligations table in the Original Filing did not include interest that will be accruing on the fixed rate long-term debt obligations as indicated by footnote 1 to the table. The numbers in the contractual obligations table have been revised in this Form 10-K/A to include the fixed rate interest accruing on the long-term debt obligations, and the total line has also been revised accordingly.

For the convenience of the reader, this Form 10-K/A includes the Original Filing in its entirety as amended by this Form 10-K/A. However, this Form 10-K/A only amends and restates the contractual obligations table of the Original Filing and no other information in the Original Filing is amended hereby. In addition, Item 15 of Part IV of the Original Filing has been amended to contain currently-dated certifications from our Chief Executive Officer and Chief Financial Officer, as required by Sections 302 and 906 of the Sarbanes-Oxley Act of 2002. The certifications of our Chief Executive Officer and Chief Financial Officer are attached to this Form 10-K/A as Exhibits 31.1, 31.2, 32.1 and 32.2.

Except for the foregoing amended information, this Form 10-K/A continues to describe conditions as of the date of the Original Filing, and the disclosures contained herein have not been updated to reflect events, results or developments that occurred after the Original Filing. Among other things, forward looking statements made in the Original Filing have not been revised to reflect events, results or developments that occurred or facts that became known to us after the date of the Original Filing, and such forward looking statements should be read in their historical context.

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Forward-Looking Statements

Statements included in this Form 10-K are forward-looking statements. In addition, we and our representatives may from time to time make other oral or written statements which are also forward-looking statements.

Such forward-looking statements include, among other things, statements regarding capital expenditures and acquisitions, expected commencement dates of mining, projected quantities of future production by our lessees producing from our reserves, and projected demand or supply for coal and aggregates that will affect sales levels, prices and royalties realized by us.

These forward-looking statements are made based upon management s current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

You should not put undue reliance on any forward-looking statements. Please read Item 1A. Risk Factors for important factors that could cause our actual results of operations or our actual financial condition to differ.

PART I

Item 1. *Business*

Natural Resource Partners L.P. is a limited partnership formed in April 2002, and we completed our initial public offering in October 2002. We engage principally in the business of owning and managing coal properties in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States. As of December 31, 2009, we owned or controlled approximately 2.1 billion tons of proven and probable coal reserves. We do not operate any mines, but lease coal reserves to experienced mine operators under long-term leases that grant the operators the right to mine our coal reserves in exchange for royalty payments. Our lessees are generally required to make payments to us based on the higher of a percentage of the gross sales price or a fixed price per ton of coal sold, in addition to minimum payments. As of December 31, 2009, our coal reserves were subject to 210 leases with 72 lessees. In 2009, our lessees produced 46.8 million tons of coal from our properties and our coal royalty revenues were $196.6 million.

Beginning in 2006, we added two new businesses: coal infrastructure and ownership of aggregate reserves that are leased to operators in exchange for royalty payments similar to our coal royalty business. During 2009, our lessees produced 3.3 million tons of aggregates and our aggregate royalties were $5.6 million, which includes a $1.3 million bonus payment under the terms of one of our leases. Coal processing fees and coal transportation fees added $7.7 million and $12.5 million in revenue, respectively.

Partnership Structure and Management

Our operations are conducted through, and our operating assets are owned by, our subsidiaries. We own our subsidiaries through a wholly owned operating company, NRP (Operating) LLC. NRP (GP) LP, our general partner, has sole responsibility for conducting our business and for managing our operations. Because our general partner is a limited partnership, its general partner, GP Natural Resource Partners LLC, conducts its business and operations, and the board of directors and officers of GP Natural Resource Partners LLC makes decisions on our behalf. Robertson Coal Management LLC, a limited liability company wholly owned by Corbin J. Robertson, Jr., owns all of the membership interest in GP Natural Resource Partners LLC. Subject to the Investor Rights Agreement with Adena Minerals, LLC, Mr. Robertson is entitled to nominate nine directors, five of whom must be independent directors, to the board of directors of GP Natural Resource Partners LLC. Mr. Robertson has delegated the right to nominate two of the directors, one of whom must be independent, to Adena Minerals.

Western Pocahontas Properties Limited Partnership, New Gauley Coal Corporation and Great Northern Properties Limited Partnership are three privately held companies that are primarily engaged in owning and managing mineral properties. We refer to these companies collectively as the WPP Group. Mr. Robertson owns the general partner of Western Pocahontas Properties, 85% of the general partner of Great Northern Properties and is the Chairman and Chief Executive Officer of New Gauley Coal Corporation.

The senior executives and other officers who manage the WPP Group assets also manage us. They are employees of Western Pocahontas Properties and Quintana Minerals Corporation, another company controlled by Mr. Robertson, and they allocate varying percentages of their time to managing our operations. Neither our general partner, GP Natural Resource Partners LLC, nor any of their affiliates receive any management fee or other compensation in connection with the management of our business, but they are entitled to be reimbursed for all direct and indirect expenses incurred on our behalf.

Our operations headquarters is located at 5260 Irwin Road, Huntington, West Virginia 25705 and the telephone number is (304) 522-5757. Our principal executive office is located at 601 Jefferson Street, Suite 3600, Houston, Texas 77002 and our phone number is (713) 751-7507.

Coal Royalty Business

Coal royalty businesses principally own and manage coal reserves. As an owner of coal reserves, we typically are not responsible for operating mines, but instead enter into leases with coal mine operators granting them the right to mine and sell coal reserves from our property in exchange for a royalty payment. A typical lease has a 5- to 10-year base term, with the lessee having an option to extend the lease for additional terms. Leases may include the right to renegotiate rents and royalties for the extended term.

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Under our standard lease, lessees calculate royalty and wheelage payments due us and are required to report tons of coal removed or hauled across our property as well as the sales prices of coal. Therefore, to a great extent, amounts reported as royalty and wheelage revenue are based upon the reports of our lessees. We periodically audit this information by examining certain records and internal reports of our lessees, and we perform periodic mine inspections to verify that the information that has been submitted to us is accurate. Our audit and inspection processes are designed to identify material variances from lease terms as well as differences between the information reported to us and the actual results from each property. Our audits and inspections, however, are in periods subsequent to when the revenue is reported and any adjustment identified by these processes might be in a reporting period different from when the royalty or wheelage revenue was initially recorded.

Coal royalty revenues are affected by changes in long-term and spot coal prices, lessees supply contracts and the royalty rates in our leases. The prevailing price for coal depends on a number of factors, including the supply-demand relationship, the price and availability of alternative fuels, global economic conditions and governmental regulations. In addition to their royalty obligation, our lessees are often subject to pre-established minimum monthly, quarterly or annual payments. These minimum rentals reflect amounts we are entitled to receive even if no mining activity occurred during the period. Minimum rentals are usually credited against future royalties that are earned as coal is produced.

Because we do not operate any mines, we do not bear ordinary operating costs and have limited direct exposure to environmental, permitting and labor risks. As operators, our lessees are subject to environmental laws, permitting requirements and other regulations adopted by various governmental authorities. In addition, the lessees generally bear all labor-related risks, including retiree health care legacy costs, black lung benefits and workers compensation costs associated with operating the mines. We typically pay property taxes and then are reimbursed by the lessee for the taxes on their leased property, pursuant to the terms of the lease.

Our business is not seasonal, although at times severe weather can cause a short-term decrease in coal production by our lessees due to the weather s negative impact on production and transportation.

Acquisitions

We are a growth-oriented company and have closed a number of acquisitions over the last several years. For a discussion of our recent acquisitions, please see Recent Acquisitions in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Coal Royalty Revenues, Reserves and Production

The following table sets forth coal royalty revenues and average coal royalty revenue per ton from the properties that we owned or controlled for the years ending December 31, 2009, 2008 and 2007. Coal royalty revenues were generated from the properties in each of the areas as follows:

	Coal Royalty Revenues for the Years Ended December 31,			Average Coal Royalty Revenue per Ton for the Years Ended December 31,		
	2009	2008	2007	2009	2008	2007
	(In thousands)			($ per ton)		
Area						

Appalachia						
Northern	$ 14,959	$ 17,074	$ 16,664	$ 3.03	$ 2.94	$ 2.29
Central	132,543	156,109	117,820	4.73	4.34	3.29
Southern	19,382	19,839	17,832	6.00	4.64	3.87
Total Appalachia	166,884	193,022	152,316	4.61	4.19	3.19
Illinois Basin	22,019	21,695	7,963	3.31	2.61	2.15
Northern Powder River Basin	7,718	11,533	11,064	1.94	1.85	1.90
Total	$ 196,621	$ 226,250	$ 171,343	$ 4.20	$ 3.74	$ 2.99

The following table sets forth production data and reserve information for the properties that we owned or controlled for the years ending December 31, 2009, 2008, and 2007. All of the reserves reported below are recoverable reserves as determined by Industry Guide 7. In excess of 90% of the reserves listed below are currently leased to third parties. Coal production data and reserve information for the properties in each of the areas is as follows:

Production and Reserves

	Production for the Year Ended December 31,			Proven and Probable Reserves at December 31, 2009		
	2009	2008	2007	Underground	Surface	Total
	(Tons in thousands)					
Area						
Appalachia						
Northern	4,943	5,799	7,270	503,086	6,642	509,728
Central	28,032	35,967	35,835	1,048,426	147,086	1,195,512
Southern	3,233	4,273	4,603	100,483	25,776	126,259
Total Appalachia	36,208	46,039	47,708	1,651,995	179,504	1,831,499
Illinois Basin	6,656	8,313	3,709	188,639	15,123	203,762
Northern Powder River Basin	3,984	6,218	5,815		109,306	109,306
Total	46,848	60,570	57,232	1,840,634	303,933	2,144,567

We classify low sulfur coal as coal with a sulfur content of less than 1.0%, medium sulfur coal as coal with a sulfur content between 1.0% and 1.5% and high sulfur coal as coal with a sulfur content of greater than 1.5%. Compliance coal is coal which meets the standards of Phase II of the Clean Air Act and is that portion of low sulfur coal that, when burned, emits less than 1.2 pounds of sulfur dioxide per million Btu. As of December 31, 2009, approximately 54% of our reserves were low sulfur coal and 35% of our reserves were compliance coal. Unless otherwise indicated, we present the quality of the coal throughout this Form 10-K on an as-received basis, which assumes 6% moisture for Appalachian reserves, 12% moisture for Illinois Basin reserves and 25% moisture for Northern Powder River Basin reserves. We own both steam and metallurgical coal reserves in Northern, Central and Southern Appalachia, and we own steam coal reserves in the Illinois Basin and the Northern Powder River Basin. In 2009, approximately 26% of the production and 33% of the coal royalty revenues from our properties were from metallurgical coal.

The following table sets forth our estimate of the sulfur content, the typical quality of our coal reserves and the type of coal in each area as of December 31, 2009.

Sulfur Content, Typical Quality and Type of Coal

		Sulfur Content				Typical Quality		Type of Coal	
		Low	Medium	High					
rea	Compliance Coal(1)	(less than 1.0%)	(1.0% to 1.5%)	(greater than 1.5%)	Total	Heat Content (Btu per pound)	Sulfur (%)	Steam	Metallurgica

	(Tons in thousands)							(Tons in thousands)	
ppalachia									
orthern	42,873	51,452	23,929	434,347	509,728	12,875	2.72	500,166	9,562
entral	620,936	900,054	263,359	32,099	1,195,512	13,440	0.89	786,826	408,686
outhern	87,572	93,910	28,531	3,818	126,259	13,500	0.82	81,638	44,621
otal Appalachia	751,381	1,045,416	315,819	470,264	1,831,499			1,368,630	462,869
inois Basin			3,314	200,448	203,762	11,550	2.86	203,762	
orthern Powder ver Basin		109,306			109,306	8,800	0.65	109,306	
otal	751,381	1,154,722	319,133	670,712	2,144,567			1,681,698	462,869

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(1) Compliance coal meets the sulfur dioxide emission standards imposed by Phase II of the Clean Air Act without blending with other coals or using sulfur dioxide reduction technologies. Compliance coal is a subset of low sulfur coal and is, therefore, also reported within the amounts for low sulfur coal.

(2) For purposes of this table, we have defined metallurgical coal reserves as reserves located in those seams that historically have been of sufficient quality and characteristics to be able to be used in the steel making process. Some of the reserves in the metallurgical category can also be used as steam coal.

We have engaged Marshall Miller and Associates, Inc. and Stagg Resource Consultants, Inc. to conduct reserve studies of our existing properties. When we began this process, we focused primarily on reserves that were owned at the time. However, as a result of the extensive nature of our reserve holdings and the large number of acquisitions that we have completed, some of the more recent studies have been on properties that were subsequently acquired. These studies will be an ongoing process and we will update the reserve studies based on our review of the following factors: the size of the properties, the amount of production that has occurred, or the development of new data which may be used in these studies. In connection with acquisitions, we have either commissioned new studies or relied on recent reports done prior to the acquisition. In addition to these studies, we base our estimates of reserve information on engineering, economic and geological data assembled and analyzed by our internal geologists and engineers. There are numerous uncertainties inherent in estimating the quantities and qualities of recoverable reserves, including many factors beyond our control. Estimates of economically recoverable coal reserves depend upon a number of variable factors and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. Some of these factors and assumptions include:

- future coal prices, mining economics, capital expenditures, severance and excise taxes, and development and reclamation costs;
- future mining technology improvements;
- the effects of regulation by governmental agencies; and
- geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experiences in other areas of our reserves.

As a result, actual coal tonnage recovered from identified reserve areas or properties may vary from estimates or may cause our estimates to change from time to time. Any inaccuracy in the estimates related to our reserves could result in royalties that vary from our expectations.

Coal Transportation and Processing Revenues

We own preparation plants and related coal handling facilities. Similar to our coal royalty structure, the throughput fees are based on a percentage of the ultimate sales price for the coal that is processed. These facilities generated $7.7 million in coal processing revenues for 2009.

In addition to our preparation plants, we own coal handling and transportation infrastructure in West Virginia, Ohio and Illinois. For the year ended December 31, 2009, we recognized $12.5 million in revenue from these assets. For the assets other than the loadout facility at the Shay No. 1 mine in Illinois, which we lease to a Cline affiliate, we operate the coal handling and transportation infrastructure and have subcontracted out that responsibility to third parties.

Aggregates Royalty Revenues, Reserves and Production

We own and manage aggregate reserves, but do not engage in the mining, processing or sale of aggregate related products. We own an estimated 130 million tons of aggregate reserves that are principally located in Washington, Texas and Arizona. We also own a small number of aggregate reserves in West Virginia. We own a total of 56 million tons of reserves at our Washington property, but only approximately 11 million of those tons are currently permitted. If the remaining tons are not permitted by December 2016, the title to those tons reverts back to the seller. The Arizona (sand and gravel) and Texas (limestone) reserves were acquired in 2009. The Arizona aggregate reserves were acquired from an existing aggregate producer in December 2009, and are currently producing revenues. The Texas aggregate reserve acquisition was part of a greenfield development effort for a limestone quarry that will be operating and producing a royalty stream for us in mid-2010. During 2009, our lessees produced 3.3 million tons of aggregates, and our aggregate royalties were $5.6 million, which includes a $1.3 million bonus payment under the terms of one of our leases.

Oil and Gas Properties

In 2009, we derived approximately 3% of our total revenues from oil and gas royalties in Kentucky, Virginia and Tennessee.

Significant Customers

In 2009, Alpha Natural Resources and affiliates of the Cline Group each represented more than 10% of our total revenues. The loss of one or both of these lessees could have a material adverse effect on us. In addition, the closure or loss of revenue from Cline s Williamson mine could have a material adverse effect on us, but we do not believe that the loss of any other single mine on our properties would have a material adverse effect on us.

Competition

We face competition from other land companies, coal producers, international steel companies and private equity firms in purchasing coal reserves and royalty producing properties. Numerous producers in the coal industry make coal marketing intensely competitive. Our lessees compete among themselves and with coal producers in various regions of the United States for domestic sales. The industry has undergone significant consolidation since 1976. This consolidation has led to a number of our lessees parent companies having significantly larger financial and operating resources than their competitors. Our lessees compete with both large and small producers nationwide on the basis of coal price at the mine, coal quality, transportation cost from the mine to the customer and the reliability of supply. Continued demand for our coal and the prices that our lessees obtain are also affected by demand for electricity and steel, as well as government regulations, technological developments and the availability and the cost of generating power from alternative fuel sources, including nuclear, natural gas and hydroelectric power.

Regulation and Environmental Matters

General. Our lessees are obligated to conduct mining operations in compliance with all applicable federal, state and local laws and regulations. These laws and regulations include matters involving the discharge of materials into the environment, employee health and safety, mine permits and other licensing requirements, reclamation and restoration of mining properties after mining is completed, management of materials generated by mining operations, surface subsidence from underground mining, water pollution, legislatively mandated benefits for current and retired coal miners, air quality standards, protection of wetlands, plant and wildlife protection, limitations on land use, storage of petroleum products and substances which are regarded as hazardous under applicable laws and management of electrical equipment containing PCBs. Because of extensive and comprehensive regulatory requirements, violations during mining operations are not unusual and, notwithstanding compliance efforts, we do not believe violations by our lessees can be eliminated entirely. However, to our knowledge none of the violations to date, nor the monetary penalties assessed, have been material to our lessees. We do not currently expect that future compliance will have a material effect on us.

While it is not possible to quantify the costs of compliance by our lessees with all applicable federal, state and local laws and regulations, those costs have been and are expected to continue to be significant. The lessees post performance bonds pursuant to federal and state mining laws and regulations for the estimated costs of reclamation and mine closures, including the cost of treating mine water discharge when necessary. We do not accrue for such costs because our lessees are both contractually liable and liable under the permits they hold for all costs relating to their mining operations, including the costs of reclamation and mine closures. Although the lessees typically accrue adequate amounts for these costs, their future operating results would be adversely affected if they later determined these accruals to be insufficient. In recent years, compliance with these laws and regulations has substantially increased the cost of coal mining for all domestic coal producers.

In addition, the electric utility industry, which is the most significant end-user of coal, is subject to extensive regulation regarding the environmental impact of its power generation activities, which could affect demand for coal mined by our lessees. The possibility exists that new legislation or regulations could be adopted that have a significant impact on the mining operations of our lessees or their customers ability to use coal and may require our lessees or their customers to change operations significantly or incur substantial costs that could impact us.

Air Emissions. The Federal Clean Air Act and corresponding state and local laws and regulations affect all aspects of our business. The Clean Air Act directly impacts our lessees coal mining and processing operations by imposing permitting requirements and, in some cases, requirements to install certain emissions control equipment, on sources that emit various hazardous and non-hazardous air pollutants. The Clean Air Act also indirectly affects coal mining operations by extensively regulating the air emissions of coal-fired electric power generating plants. There have been a series of federal rulemakings that are focused on emissions from coal-fired electric generating facilities. Installation of additional emissions control technology and additional measures required under U.S. Environmental Protection Agency (or EPA) laws and regulations will make it more costly to operate coal-fired power plants and, depending on the requirements of individual state and regional implementation plans, could make coal a less attractive fuel source in the planning and building of power plants in the future. Any reduction in coal s share of power generating capacity could negatively impact our lessees ability to sell coal, which would have a material effect on our coal royalty revenues.

In 1997, the EPA promulgated a rule, referred to as the NOx SIP Call, that required coal-fired power plants and other large stationary sources in 21 eastern states and Washington D.C. to make substantial reductions in nitrogen oxide emissions in an effort to reduce the impacts of ozone transport between states. Additionally, in March 2005, the EPA issued the final Clean Air Interstate Rule (or CAIR), which, if it remains in effect, would permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. CAIR will require these states to achieve the required emission reductions by requiring power plants to either participate in an EPA-administered cap-and-trade program that caps emission in two phases, or by meeting an individual state emissions budget through measures established by the state. We believe that the financial impact of the CAIR on coal markets has been factored into the price of coal nationally and that its impact on demand has largely been taken into account by the marketplace. However, the CAIR was challenged and the Federal District Court of Appeals for the D.C. Circuit vacated the CAIR on July 11, 2008. *North Carolina v. EPA*, No. 05-1244 (D.C. Cir. Jul. 11, 2008). The vacatur caused significant uncertainty regarding state implementing regulations that were based on the CAIR. Upon request for reconsideration, though, the Court on December 23, 2008, subsequently revised its remedy to a remand to EPA without providing a response deadline. The EPA is expected to propose a revised rule in 2010 and complete its rule making in 2011. Accordingly, all state regulations that were based on the CAIR are still in effect, but we are unable to predict the outcome of EPA s response to the remand and, therefore, unable to predict any effect on NRP.

In March 2005, the EPA finalized the Clean Air Mercury Rule (or CAMR), which establishes a two-part, nationwide cap on mercury emissions from coal-fired power plants beginning in 2010. The CAMR was vacated in early 2008 by the Federal Court of Appeals for the District of Columbia Circuit in *State of New Jersey v. EPA*, No. 05-1097 (D.C. Cir. Feb. 8, 2008) and the appeal process has not concluded. However, if fully implemented, CAMR would permit states to implement their own mercury control regulations or participate in an interstate cap-and-trade program for mercury emission allowances.

Continued tightening of the already stringent regulation of emissions is likely, such as EPA s proposal published on December 8, 2009 to revise the national ambient air quality standard for oxides of sulfur and a similar proposal announced on January 6, 2010 for ozone. As a result, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. For example, in December 2004, the EPA designated specific areas in the United States as non-attainment areas, meaning that the designated areas failed to meet the new national ambient air quality standard for fine particulate matter. In May of 2007, EPA published a final rule requiring that each state having a nonattainment area submit to EPA by April 5, 2008, an attainment demonstration and adopt regulations ensuring that the area will attain the standards as expeditiously as practicable, but no later than 2015. The same process is being played out with respect to the new ozone standard, but with later attainment dates. Significant additional emission control expenditures will be required at coal-fueled power plants to meet the new standards for ozone.

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In June 2005, the EPA announced final amendments to its regional haze program originally developed in 1999 to improve visibility in national parks and wilderness areas. Under the Regional Haze Rule, affected states were to have developed implementation plans by December 17, 2007 that, among other things, identify facilities that will have to reduce emissions and comply with stricter emission limitations. The vast majority of states failed to submit their plans by December 17, 2007, and EPA issued a Finding of Failure to Submit plans on January 15, 2009 (74 Fed. Reg. 2392), which could trigger Federal plan implementation. This program may restrict construction of new coal-fired power plants where emissions are projected to reduce visibility in protected areas. In addition, this program may require certain existing coal-fired power plants to install emissions control equipment to reduce haze-causing emissions such as sulfur dioxide, nitrogen oxide and particulate matter.

Regulation of additional emissions such as carbon dioxide or other greenhouse gases as proposed or determined by EPA on October 27, October 30 and December 15, 2009 may eventually be applied to stationary sources such as coal-fueled power plants and industrial boilers (see discussion of Carbon Dioxide and Greenhouse Gas Emissions below). Coal mining operations emit particulate matter and coal-fired electric generating facilities emit all forms of pollutants regulated by the Clean Air Act. For this reason our lessees   mining operations and their customers could be affected when these new standards are implemented by the applicable states, and their application could eventually reduce the demand for coal.

The U.S. Department of Justice, on behalf of the EPA, has filed lawsuits against a number of utilities with coal-fired electric generating facilities alleging violations of the new source review provisions of the Clean Air Act. The EPA has alleged that certain modifications have been made to these facilities without first obtaining permits issued under the new source review program. Several of these lawsuits have settled, but others remain pending. Depending on the ultimate resolution of these cases, demand for our coal could be affected, which could have an adverse effect on our coal royalty revenues.

Carbon Dioxide and Greenhouse Gas Emissions. In the mid-1990 s, the Kyoto Protocol to the United Nations Framework Convention on Climate Change called for developed nations to reduce their emissions of greenhouse gases to five percent below 1990 levels by 2012. Carbon dioxide, which is a major byproduct of the combustion of coal and other fossil fuels, is subject to the Kyoto Protocol. The Kyoto Protocol went into effect on February 16, 2005 for those nations that ratified the treaty. The United States has not ratified the Kyoto Protocol, although it continues to participate actively in international discussions such as the December 2009 meeting in Copenhagen.

The United States Congress has begun considering multiple bills that would regulate domestic carbon dioxide emissions, but no such bill has yet received sufficient Congressional support for passage into law. The existing Clean Air Act is also a possible mechanism for regulating greenhouse gases. In April 2007, the U.S. Supreme Court rendered its decision in Massachusetts v. EPA, finding that the EPA has authority under the Clean Air Act to regulate carbon dioxide emissions from automobiles and can decide against regulation only if the EPA determines that carbon dioxide does not significantly contribute to climate change and does not endanger public health or the environment. In response to Massachusetts v. EPA, in July 2008, the EPA issued a notice of proposed rulemaking requesting public comment on the regulation of greenhouse gases. On October 27, 2009 EPA announced how it will establish thresholds for phasing-in and regulating greenhouse gas emissions under various provisions of the Clean Air Act. Three days later, on October 30, 2009, EPA published a final rule in the Federal Register that requires the reporting of greenhouse gas emissions from all sectors of the American economy, although reporting of emissions from underground coal mines and coal suppliers as originally proposed has been deferred pending further review. On December 15, 2009, EPA published a formal determination that six greenhouse gases, including carbon dioxide and methane, endanger both the public health and welfare of current and future generations. In the same Federal Register rulemaking, EPA found that emission of greenhouse gases from new motor vehicles and their engines contribute to greenhouse gas pollution. Although Massachusetts v. EPA did not involve the EPA s authority to regulate greenhouse gas emissions from stationary sources, such as coal-fueled power plants, the decision is likely to impact regulation of stationary sources.

Several states have also either passed legislation or announced initiatives focused on decreasing or stabilizing carbon dioxide emissions associated with the combustion of fossil fuels, and many of these measures have focused on emissions from coal-fired electric generating facilities. For example, in December 2005, seven northeastern states agreed to implement a regional cap-and-trade program to stabilize carbon

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dioxide emissions from regional power plants beginning in 2009. In addition, a challenge in the U.S. Court of Appeals for the District of Columbia with respect to the EPA s decision not to regulate greenhouse gas emissions from power plants and other stationary sources under the Clean Air Act s new source performance standards was remanded to the EPA for further consideration in light of Massachusetts v. EPA. The U.S. Court of Appeals for the Second Circuit has heard oral argument in a public nuisance action filed by eight states (Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont) and New York City to curb carbon dioxide emissions from power plants. The parties have filed post-argument briefs on the impact of the Massachusetts v. EPA decision, and a decision is currently pending. Other regional programs are being considered in several regions of the country.

It is possible that future federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with coal consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs for coal consumption could result in some customers switching to alternative sources of fuel, which could negatively impact our lessees coal sales, and thereby have an adverse effect on our coal royalty revenues.

Surface Mining Control and Reclamation Act of 1977. The Surface Mining Control and Reclamation Act of 1977 (or SMCRA) and similar state statutes impose on mine operators the responsibility of reclaiming the land and compensating the landowner for types of damages occurring as a result of mining operations, and require mine operators to post performance bonds to ensure compliance with any reclamation obligations. In conjunction with mining the property, our coal lessees are contractually obligated under the terms of our leases to comply with all Federal, state and local laws, including SMCRA. Upon completion of the mining, reclamation generally is completed by seeding with grasses or planting trees for use as pasture or timberland, as specified in the approved reclamation plan. In addition, higher and better uses of the reclaimed property are encouraged. Regulatory authorities may attempt to assign the liabilities of our coal lessees to us if any of these lessees are not financially capable of fulfilling those obligations.

Hazardous Materials and Waste. The Federal Comprehensive Environmental Response, Compensation and Liability Act (or CERCLA or the Superfund law), and analogous state laws, impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources.

Some products used by coal companies in operations generate waste containing hazardous substances. We could become liable under federal and state Superfund and waste management statutes if our lessees are unable to pay environmental cleanup costs. CERCLA authorizes the EPA and, in some cases, third parties, to take actions in response to threats to the public health or the environment, and to seek recovery from the responsible classes of persons of the costs they incurred in connection with such response. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other wastes released into the environment.

Water Discharges. Our lessees operations can result in discharges of pollutants into waters. The Clean Water Act and analogous state laws and regulations impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States. The unpermitted discharge of pollutants such as from spill or leak incidents is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of fill material and certain other activities in wetlands unless authorized by an appropriately issued permit.

Our lessees mining operations are strictly regulated by the Clean Water Act, particularly with respect to the discharge of overburden and fill material into waters, including wetlands. Recent federal district court decisions in West Virginia, and related litigation filed in federal district court in Kentucky, have created uncertainty regarding the future ability to obtain certain general permits authorizing the construction of valley fills for the disposal of overburden from mining operations. A July 2004 decision by the federal court for the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Bulen* enjoined the Huntington

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District of the U.S. Army Corps of Engineers from issuing further permits pursuant to Nationwide Permit 21, which is a general permit issued by the U.S. Army Corps of Engineers to streamline the process for obtaining permits under Section 404 of the Clean Water Act. While the decision was reversed and remanded to district court by the Fourth Circuit Court of Appeals in November 2005, the district court is currently considering additional challenges to Nationwide Permit 21. Additionally, a similar lawsuit filed in federal district court in Kentucky seeks to enjoin the issuance of permits pursuant to Nationwide Permit 21 by the Louisville District of the U.S. Army Corps of Engineers. In the event that such lawsuits prove to be successful, some of our lessees may be required to apply for individual discharge permits pursuant to Section 404 of the Clean Water Act in areas where they would have otherwise utilized Nationwide Permit 21.

Aside from these lawsuits, on July 15, 2009, the Corps proposed to immediately suspend the use of the Nationwide Permit 21 in six Appalachian states, including West Virginia, Kentucky and Virginia, where our lessees conduct operations. In the same notice, the Corps proposed to modify the Nationwide Permit 21 following the receipt and review of public comments to prohibit its further use in the same states during the remaining term of the permit, which is March 12, 2012. The Corps is now reviewing the more than 21,000 public comments it has received. The agency has not announced when it is expected to complete its review and reach a final decision.

Regardless of the outcome of the Corps decision about any continuing use of Nationwide Permit 21, it does not prevent our lessees from seeking an individual permit under § 404 of the Clean Water Act, nor does it restrict an operation from utilizing another version of the nationwide permit authorized for small underground coal mines that must construct fills as part of their mining operations. Nevertheless, such changes will result in delays in our lessees obtaining the required mining permits to conduct their operations, which could in turn have an adverse effect on our coal royalty revenues. Moreover, such individual permits are also subject to challenge.

In 2007, two decisions by the Southern District of West Virginia in *Ohio Valley Environmental Coalition v. Strock* complicated the ability of our lessees both to obtain individual permits from the Corps of Engineers without performing a full environmental impact statement and to construct in-stream sediment ponds to control sediment from their excess spoil valley fills. The first decision, dated March 23, 2007 rescinded four individual permits issued to Massey Energy Company subsidiaries as a result of the Corps failure to properly evaluate the impacts of filling on small headwater streams and to ensure such impacts were appropriately minimized with mitigation efforts. This order has had the effect of slowing the flow of new fill permits from the Corps Huntington, West Virginia, District Office.

The second order, dated June 13, 2007, ruled that discharges of sediment from valley fills into sediment ponds constructed in-stream to collect and treat that sediment must meet the same standards as are applied to discharges from these sediment ponds. Because of the rugged terrain in central Appalachia, often the only practicable location for these ponds is in streams. The effect of the ruling is not yet clear, but it may require our lessees to disturb substantially more surface area to construct sediment structures out of the stream channels. A similar lawsuit (*Kentucky Waterways Alliance, Inc. v. United States Army Corps of Engineers,* Civil Action No. 3:07-cv-00677 (W.D. Ky. 2007)) was filed in the Western District of Kentucky and may affect future permitting by the Louisville, Kentucky District Office as well.

The Fourth Circuit reversed both orders on February 13, 2009, but the plaintiffs then asked the United States Supreme Court to review the decision. Although Massey and the other coal industry Intervenors in the case prefer the Court not to hear the case, neither the Corps nor the Intervenors have filed any response to the Plaintiffs petition because of an extension of the response deadline sought by the Corps. It is likely that the Corps and the Plaintiffs are in discussions that will result in the case being moot. If the Fourth Circuit decision stands, then a backlog of permits pending before the Corps of Engineers may ease.

Federal and state surface mining laws require mine operators to post reclamation bonds to guarantee the costs of mine reclamation. West Virginia s bonding system requires coal companies to post site-specific bonds in an amount up to $5,000 per acre and imposes a per-ton tax on mined coal currently set at $0.07/ton, which is paid to the West Virginia Special Reclamation Fund (SRF). The site-specific bonds are used to reclaim the mining operations of companies which default on their obligations under the West Virginia Surface Coal Mining and Reclamation Act. The SRF is used where the site-specific bonds are insufficient to accomplish reclamation. In *The West Virginia Highlands Conservancy, Plaintiff, v. Dirk Kempthorne, Secretary of the Department of the Interior, et al., Defendants, and the West Virginia Coal Association, Intervenor/Defendan*t, Civil Action No. 2:00-cv-1062 (United States District Court for the Southern District of West Virginia), an environmental group is claiming that the SRF is underfunded and that the Federal Office of Surface Mining (OSM) has an obligation under the Federal Surface Mining Act to ensure that the SRF funds are increased to cover the supposed shortfall. On March 23, 2007, the plaintiff moved to reopen this long inactive case on the grounds that a recommendation of the state s Special Reclamation Advisory Council regarding the establishment of a $175 million trust fund for water treatment at future bond forfeiture sites has not been approved. A one-year increase in the reclamation tax was enacted in the 2008 Legislative Session. Following this legislative action, the plaintiff moved the Court to defer ruling on its motion to reopen the case until it is determined whether the increase will be re-enacted and whether it will be sufficient if West Virginia Department of Environmental Protection (WVDEP) is required to obtain National Pollution Discharge Elimination System (NPDES) permits at 21 bond forfeiture sites relief sought in two separate citizens suits pending against WVDEP. In a May 15, 2008 Order, the Court denied plaintiff s motion to reopen without prejudice, denied the plaintiff s motion to defer, except insofar as it sought denial of the motion to reopen without prejudice, and retained the case on the inactive docket of the Court. In a companion case, *West Virginia Highlands Conservancy v. Huffman,* Civil Action No. 1:07-cv-87 (United States District Court, Northern District of West Virginia), the Court granted summary judgment on January 14, 2009 and required the WVDEP to obtain NPDES permits for bond forfeiture sites in the northern part of West Virginia. The WVDEP, joined by other states has appealed this decision to the Fourth Circuit.

If the Court ultimately rules that OSM has an obligation either to assume federal control of the State bonding program or to require the State to increase the money in the SRF, our lessees could be forced to bear an increase in the tax on mined coal to increase the size of the SRF.

The Clean Water Act also requires states to develop anti-degradation policies to ensure non-impaired water bodies in the state do not fall below applicable water quality standards. These and other regulatory developments may restrict our lessees ability to develop new mines, or could require our lessees to modify existing operations, which could have an adverse effect on our coal royalty revenues.

The Federal Safe Drinking Water Act (or SDWA) and its state equivalents affect coal mining operations by imposing requirements on the underground injection of fine coal slurries, fly ash and flue gas scrubber sludge, and by requiring permits to conduct such underground injection activities. In addition to establishing the underground injection control program, the SDWA also imposes regulatory requirements on owners and operators of public water systems. This regulatory program could impact our lessees reclamation operations where subsidence or other mining-related problems require the provision of drinking water to affected adjacent homeowners.

Mine Health and Safety Laws. The operations of our lessees are subject to stringent health and safety standards that have been imposed by federal legislation since the adoption of the Mine Health and Safety Act of 1969. The Mine Health and Safety Act of 1969 resulted in increased operating costs and reduced productivity. The Mine Safety and Health Act of 1977, which significantly expanded the enforcement of health and safety standards of the Mine Health and Safety Act of 1969, imposes comprehensive health and safety standards on all mining operations. In addition, the Black Lung Acts require payments of benefits by all businesses conducting current mining operations to coal miners with black lung or pneumoconiosis and to some beneficiaries of miners who have died from this disease.

Mining accidents in recent years have received national attention and instigated responses at the state and national level that have resulted in increased scrutiny of current safety practices and procedures at all mining operations, particularly underground mining operations. In January 2006, West Virginia passed a law imposing stringent new mine safety and accident reporting requirements and increased civil and criminal penalties for violations of mine safety laws. Similarly, on April 27, 2006, the Governor of Kentucky signed mine safety legislation that includes requirements for increased inspections of underground mines and additional mine safety equipment and authorizes the assessment of penalties of up to $5,000 per incident for violations of mine ventilation or roof control requirements.

On June 15, 2006, President Bush signed new mining safety legislation that mandates similar improvements in mine safety practices; increases civil and criminal penalties for non-compliance; requires the creation of additional mine rescue teams, and expands the scope of federal oversight, inspection and enforcement activities. Earlier, the federal Mine Safety and Health Administration announced the promulgation of new emergency rules on mine safety that took effect immediately upon their publication in the Federal Register on March 9, 2006. These rules address mine safety equipment, training, and emergency reporting requirements.

Mining Permits and Approvals. Numerous governmental permits or approvals are required for mining operations. In connection with obtaining these permits and approvals, our lessees may be required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that any proposed production of coal may have upon the environment. The requirements imposed by any of these authorities may be costly and time consuming and may delay commencement or continuation of mining operations.

In order to obtain mining permits and approvals from state regulatory authorities, mine operators, including our lessees, must submit a reclamation plan for reclaiming the mined property, upon the completion of mining operations. Typically, our lessees submit the necessary permit applications between 12 and 24 months before they plan to begin mining a new area. In our experience, permits generally are approved within 12 months after a completed application is submitted. In the past, our lessees have generally obtained their mining permits without significant delay. Our lessees have obtained or applied for permits to mine a majority of the reserves that are currently planned to be mined over the next five years. Our lessees are also in the planning phase for obtaining permits for the additional reserves planned to be mined over the following five years. However, there are no assurances that they will not experience difficulty and delays in obtaining mining permits in the future.

Employees and Labor Relations

We do not have any employees. To carry out our operations, affiliates of our general partner employ approximately 71 people who directly support our operations. None of these employees are subject to a collective bargaining agreement.

Segment Information

We conduct all of our operations in a single segment the ownership and leasing of mineral properties and related transportation and processing infrastructure. Substantially all of our owned properties are subject to leases, and revenues are earned based on the volume and price of minerals extracted, processed or transported. We consider revenues from timber and oil and gas acquired as part of the acquisition of our mineral reserves to be incidental to our business focus and those revenues constitute less than 10% of our total revenues and assets. We anticipate that these assets will continue to be incidental to our primary business in the future.

Website Access to Company Reports

Our internet address is *www.nrplp.com*. We make available free of charge on or through our internet website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Also included on our website are our Code of Business Conduct and Ethics , our Disclosure Controls and Procedures Policy and our Corporate Governance Guidelines adopted by our Board of Directors and the charters for our Audit Committee, Conflicts Committee and Compensation, Nominating and Governance Committee. Also, copies of our annual report, our Code of Business Conduct and Ethics, our Corporate Governance Guidelines and our committee charters will be made available upon written request.

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

Risks Related to our Business

A substantial or extended decline in coal prices could reduce our coal royalty revenues and the value of our reserves.

The prices our lessees receive for their coal depend upon other factors beyond their or our control, including:

- the supply of and demand for domestic and foreign coal;
- domestic and foreign governmental regulations and taxes;

the price and availability of alternative fuels;

the proximity to and capacity of transportation facilities;

weather conditions; and

the effect of worldwide energy conservation measures.

A substantial or extended decline in coal prices could materially and adversely affect us in two ways. First, lower prices may reduce the quantity of coal that may be economically produced from our properties. This, in turn, could reduce our coal royalty revenues and the value of our coal reserves. Second, even if production is not reduced, the royalties we receive on each ton of coal sold may be reduced.

Any decrease in the demand for metallurgical coal could result in lower coal production by our lessees, which would reduce our coal royalty revenues.

Our lessees produce a significant amount of the metallurgical coal that is used in both the U.S. and foreign steel industries. In 2009, approximately 26% of the coal production and 33% of the coal royalty revenues from our properties were from metallurgical coal. Since the amount of steel that is produced is tied to global economic conditions, a decline in those conditions could result in the decline of steel, coke and metallurgical coal production. Since metallurgical coal is priced higher than steam coal, some mines on our properties may only operate profitably if all or a portion of their production is sold as metallurgical coal. If these mines are unable to sell metallurgical coal, they may not be economically viable and may close. The steel industry has increasingly relied on electric arc furnaces or pulverized coal processes to make steel. If this trend continues, the amount of metallurgical coal that our lessees mine could decrease.

The adoption of climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs for our lessees and reduced demand for our coal.

In April 2009, the Environmental Protection Agency, or EPA, issued a notice of its findings and determination that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, presented an endangerment to human health and the environment because such gases are, according to EPA, contributing to warming of the earth s atmosphere and other climatic changes. Finalization of EPA s finding and determination will allow it to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. In September 2009, EPA proposed two sets of regulations in response to its finding and determination, one to reduce emissions of GHGs from motor vehicles and the other to control emissions from large stationary sources, including coal-fired electric power plants. Any limitation on emissions of GHGs from the operations of consumers of coal could cause them to incur additional costs and reduce the demand for coal.

On June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. The purpose of ACESA is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth s atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA s overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as coal.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could have an adverse effect on the demand for our coal. Even if such legislation is not adopted at the national level, more than one-third of the states have begun taking actions to control and/or reduce emissions of GHGs. Most of the state-level initiatives to date have been focused on large sources of GHGs, such as coal-fired electric power plants. These state initiatives also could have an adverse effect on the demand for our coal.

In addition, two federal Courts of Appeals recently allowed lawsuits in which the plaintiffs assert common law causes of action, including that emissions of GHGs constitute a nuisance, to proceed against certain entities, including in one of the cases, Natural Resource Partners. The courts rulings could prompt additional similar litigation. An adverse outcome for the defendants in these or other similar cases could adversely affect the demand for our coal.

In addition to the climate change legislation, our lessees are subject to numerous other federal, state and local laws and regulations that may limit their ability to produce and sell minerals from our properties.

Our lessees may incur substantial costs and liabilities under increasingly strict federal, state and local environmental, health and safety laws, including regulations and governmental enforcement policies. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of cleanup and site restoration costs and liens, the issuance of injunctions to limit or cease operations, the suspension or revocation of permits and other enforcement measures that could have the effect of limiting production from our lessees operations.

New environmental legislation, new regulations and new interpretations of existing environmental laws, including regulations governing permitting requirements, could further regulate or tax the mineral industry and may also require our lessees to change their operations significantly, to incur increased costs or to obtain new or different permits, any of which could decrease our royalty revenues.

We may not be able to expand and our business will be adversely affected if we are unable to replace or increase our reserves, obtain other mineral reserves through acquisitions or effectively integrate new assets into our existing business.

Because our reserves decline as our lessees mine our minerals, our future success and growth depend, in part, upon our ability to acquire additional reserves that are economically recoverable. If we are unable to acquire additional mineral reserves on acceptable terms, our royalty revenues will decline as our reserves are depleted. Our ability to acquire additional mineral reserves is dependent in part on our ability to access the capital markets. In addition, if we are unable to successfully integrate the companies, businesses or properties we are able to acquire, our royalty revenues may decline and we could experience a material adverse effect on our business, financial condition or results of operations.

If we acquire additional reserves, there is a possibility that any acquisition could be dilutive to our earnings and reduce our ability to make distributions to unitholders. Any debt we incur to finance an acquisition may also reduce our ability to make distributions to unitholders. Our ability to make acquisitions in the future also could be limited by restrictions under our existing or future debt agreements, competition from other mineral companies for attractive properties or the lack of suitable acquisition candidates.

We may not be able to obtain long-term financing on acceptable terms, which would limit our ability to make acquisitions and pay distributions to our unitholders.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers.

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Due to these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our revenues, results of operations and quarterly distributions.

Some of our lessees may be adversely impacted by the instability of the credit markets.

Many of our lessees finance their activities through cash flow from operations, the incurrence of debt, the use of commercial paper or the issuance of equity. Recently, there has been a significant deterioration in the credit markets and the availability of credit. The lack of availability of debt or equity financing may result in a significant reduction in our lessees spending related to development of new mines or expansion of existing mines on our properties. It may also impact our lessees ability to pay current obligations and continue ongoing operations on our properties. Any significant reductions in spending related to our lessees operations could have a material adverse effect on our revenues and ability to pay our quarterly distributions.

Our lessees mining operations are subject to operating risks that could result in lower royalty revenues to us.

Our royalty revenues are largely dependent on our lessees level of production from our mineral reserves. The level of our lessees production is subject to operating conditions or events beyond their or our control including:

- the inability to acquire necessary permits or mining or surface rights;
- changes or variations in geologic conditions, such as the thickness of the mineral deposits and, in the case of coal, the amount of rock embedded in or overlying the coal deposit;
- the price of natural gas, which is a competing fuel in the generation of electricity;
- changes in governmental regulation of the coal industry or the electric utility industry;
- mining and processing equipment failures and unexpected maintenance problems;
- interruptions due to transportation delays;
- adverse weather and natural disasters, such as heavy rains and flooding;
- labor-related interruptions; and
- fires and explosions.

Our lessees may also incur costs and liabilities resulting from claims for damages to property or injury to persons arising from their operations. If our lessees are pursued for these sanctions, costs and liabilities, their mining operations and, as a result, our royalty revenues could be adversely affected.

There have been several recent lawsuits filed in Central Appalachia that will potentially make it much more difficult for our lessees to obtain permits to mine our coal. The most likely impact of the litigation will be to increase both the cost to our lessees of acquiring permits and the time that it will take for them to receive the permits. These conditions may increase our lessees cost of mining and delay or halt production at particular mines for varying lengths of time or permanently. Any interruptions to the production of coal from our reserves may reduce our coal royalty revenues.

If our lessees do not manage their operations well, their production volumes and our royalty revenues could decrease.

We depend on our lessees to effectively manage their operations on our properties. Our lessees make their own business decisions with respect to their operations within the constraints of their leases, including decisions relating to:

- marketing of the minerals mined;
- mine plans, including the amount to be mined and the method of mining;
- processing and blending minerals;
- expansion plans and capital expenditures;

credit risk of their customers;

permitting;

insurance and surety bonding;

acquisition of surface rights and other mineral estates;

employee wages;

transportation arrangements;

compliance with applicable laws, including environmental laws; and

mine closure and reclamation.

A failure on the part of one of our lessees to make royalty payments could give us the right to terminate the lease, repossess the property and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement lessee. We might not be able to find a replacement lessee and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the existing lessee could be subject to bankruptcy proceedings that could further delay the execution of a new lease or the assignment of the existing lease to another operator. If we enter into a new lease, the replacement operator might not achieve the same levels of production or sell minerals at the same price as the lessee it replaced. In addition, it may be difficult for us to secure new or replacement lessees for small or isolated mineral reserves, since industry trends toward consolidation favor larger-scale, higher-technology mining operations in order to increase productivity.

Fluctuations in transportation costs and the availability or reliability of transportation could reduce the production of minerals mined from our properties.

Transportation costs represent a significant portion of the total delivered cost for the customers of our lessees. Increases in transportation costs could make coal a less competitive source of energy or could make minerals produced by some or all of our lessees less competitive than coal produced from other sources. On the other hand, significant decreases in transportation costs could result in increased competition for our lessees from producers in other parts of the country.

Our lessees depend upon railroads, barges, trucks and beltlines to deliver minerals to their customers. Disruption of those transportation services due to weather-related problems, mechanical difficulties, strikes, lockouts, bottlenecks and other events could temporarily impair the ability of our lessees to supply minerals to their customers. Our lessees transportation providers may face difficulties in the future that may impair the ability of our lessees to supply minerals to their customers, resulting in decreased royalty revenues to us.

Lessees could satisfy obligations to their customers with minerals from properties other than ours, depriving us of the ability to receive amounts in excess of minimum royalty payments.

Mineral supply contracts do not generally require operators to satisfy their obligations to their customers with resources mined from specific reserves. Several factors may influence a lessee s decision to supply its customers with minerals mined from properties we do not own or lease, including the royalty rates under the lessee s lease with us, mining conditions, mine operating costs, cost and availability of transportation, and customer specifications. If a lessee satisfies its obligations to its customers with minerals from properties we do not own or lease, production on our properties will decrease, and we will receive lower royalty revenues.

Our growing coal infrastructure business exposes us to risks that we do not experience in the royalty business.

Over the past three years, we have acquired several coal preparation plants, load-out facilities and beltlines. These facilities are subject to mechanical and operational breakdowns that could halt or delay the transportation and processing of coal, and therefore decrease our revenues. In addition, we have assumed the operating risks associated with the transportation infrastructure at two mines. Although we have sub-contracted out this work to a third party, we could experience increased costs as well as increased liability exposure associated with operating these facilities.

Our reserve estimates depend on many assumptions that may be inaccurate, which could materially adversely affect the quantities and value of our reserves.

Our reserve estimates may vary substantially from the actual amounts of minerals our lessees may be able to economically recover from our reserves. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. Estimates of reserves necessarily depend upon a number of variables and assumptions, any one of which may, if incorrect, result in an estimate that varies considerably from actual results. These factors and assumptions relate to:

- future prices, operating costs, capital expenditures, severance and excise taxes, and development and reclamation costs;
- future mining technology improvements;
- the effects of regulation by governmental agencies; and
- geologic and mining conditions, which may not be fully identified by available exploration data and may differ from our experiences in areas where our lessees currently mine.

Actual production, revenue and expenditures with respect to our reserves will likely vary from estimates, and these variations may be material. As a result, you should not place undue reliance on our reserve data that is included in this report.

A lessee may incorrectly report royalty revenues, which might not be identified by our lessee audit process or our mine inspection process or, if identified, might be identified in a subsequent period.

We depend on our lessees to correctly report production and royalty revenues on a monthly basis. Our regular lessee audits and mine inspections may not discover any irregularities in these reports or, if we do discover errors, we might not identify them in the reporting period in which they occurred. Any undiscovered reporting errors could result in a loss of royalty revenues and errors identified in subsequent periods could lead to accounting disputes as well as disputes with our lessees.

Risks Inherent in an Investment in Natural Resource Partners L.P.

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

Cost reimbursements due to our general partner may be substantial and will reduce our cash available for distribution to unitholders.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates, including officers and directors of the general partner, for all expenses incurred on our behalf. The reimbursement of expenses and the payment of fees could adversely affect our ability to make distributions. The general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates may provide us services for which we will be charged reasonable fees as determined by the general partner.

Unitholders may not be able to remove our general partner even if they wish to do so.

Our general partner manages and operates NRP. Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business. Unitholders have no right to elect the general partner or the directors of the general partner on an annual or any other basis.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have little practical ability to remove our general partner or otherwise change its management. Our general

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partner may not be removed except upon the vote of the holders of at least 662/3% of our outstanding units (including units held by our general partner and its affiliates). Because the owners of our general partner, along with directors and executive officers and their affiliates, own a significant percentage of our outstanding common units, the removal of our general partner would be difficult without the consent of both our general partner and its affiliates.

In addition, the following provisions of our partnership agreement may discourage a person or group from attempting to remove our general partner or otherwise change our management:

- generally, if a person acquires 20% or more of any class of units then outstanding other than from our general partner or its affiliates, the units owned by such person cannot be voted on any matter; and

- limitations upon the ability of unitholders to call meetings or to acquire information about our operations, as well as other limitations upon the unitholders ability to influence the manner or direction of management.

As a result of these provisions, the price at which the common units will trade may be lower because of the absence or reduction of a takeover premium in the trading price.

We may issue additional common units without unitholder approval, which would dilute a unitholder s existing ownership interests.

Our general partner may cause us to issue an unlimited number of common units, without unitholder approval (subject to applicable NYSE rules). We may also issue at any time an unlimited number of equity securities ranking junior or senior to the common units without unitholder approval (subject to applicable NYSE rules). The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- an existing unitholder s proportionate ownership interest in NRP will decrease;

- the amount of cash available for distribution on each unit may decrease;

- the relative voting strength of each previously outstanding unit may be diminished; and

- the market price of the common units may decline.

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own 80% or more of the common units, the general partner will have the right, but not the obligation, which it may assign to any of its affiliates, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price generally equal to the then current market price of the common units. As a result, unitholders may be required to sell their common units at a time when they may not desire to sell them or at a price that is less than the price they would like to receive. They may also incur a tax liability upon a sale of their common units.

Unitholders may not have limited liability if a court finds that unitholder actions constitute control of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those contractual obligations that are expressly made without recourse to our general partner. Under Delaware law, however, a unitholder could be held liable for our obligations to the same extent as a general partner if a court determined that the right of unitholders to remove our general partner or to take other action under our partnership agreement constituted participation in the control of our business. In addition, Section 17-607 of the Delaware Revised Uniform Limited Partnership Act provides that under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of three years from the date of the distribution.

Conflicts of interest could arise among our general partner and us or the unitholders.

These conflicts may include the following:

- we do not have any employees and we rely solely on employees of affiliates of the general partner;

under our partnership agreement, we reimburse the general partner for the costs of managing and for operating the partnership;

the amount of cash expenditures, borrowings and reserves in any quarter may affect cash available to pay quarterly distributions to unitholders;

the general partner tries to avoid being liable for partnership obligations. The general partner is permitted to protect its assets in this manner by our partnership agreement. Under our partnership agreement the general partner would not breach its fiduciary duty by avoiding liability for partnership obligations even if we can obtain more favorable terms without limiting the general partner s liability;

under our partnership agreement, the general partner may pay its affiliates for any services rendered on terms fair and reasonable to us. The general partner may also enter into additional contracts with any of its affiliates on behalf of us. Agreements or contracts between us and our general partner (and its affiliates) are not necessarily the result of arms length negotiations; and

the general partner would not breach our partnership agreement by exercising its call rights to purchase limited partnership interests or by assigning its call rights to one of its affiliates or to us.

The control of our general partner may be transferred to a third party without unitholder consent. A change of control may result in defaults under certain of our debt instruments and the triggering of payment obligations under compensation arrangements.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the general partner of our general partner from transferring its general partnership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers with its own choices and to control their decisions and actions.

In addition, a change of control would constitute an event of default under our revolving credit agreement. During the continuance of an event of default under our revolving credit agreement, the administrative agent may terminate any outstanding commitments of the lenders to extend credit to us and/or declare all amounts payable by us immediately due and payable. A change of control also may trigger payment obligations under various compensation arrangements with our officers.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to you would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

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Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such a tax on us by any state will reduce the cash available for distribution to you.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. Furthermore, a portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion and depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the Department of the Treasury and the IRS issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Although existing publicly traded partnerships are entitled to rely on these proposed Treasury Regulations, they are not binding on the IRS and are subject to change until final Treasury Regulations are issued.

A unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We will adopt certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

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A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in our filing two tax returns for one fiscal year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred.

Certain federal income tax preferences currently available with respect to coal exploration and development may be eliminated as a result of future legislation.

Among the changes contained in the President s Budget Proposal for Fiscal Year 2011 is the elimination of certain key U.S. federal income tax preferences relating to coal exploration and development. The Budget Proposal would (i) eliminate current deductions and 60-month amortization for exploration and development costs relating to coal and other hard mineral fossil fuels, (ii) repeal the percentage depletion allowance with respect to coal properties, (iii) repeal capital gains treatment of coal and lignite royalties, and (iv) exclude from the definition of domestic production gross receipts all gross receipts derived from the sale, exchange, or other disposition of coal, other hard mineral fossil fuels, or primary products thereof. The passage of any legislation as a result of the Budget Proposal or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to coal exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

As a result of investing in our common units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.

In addition to federal income taxes, you will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. You will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. We own property and conduct business in a number of states in the United States. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is your responsibility to file all United States federal, foreign, state and local tax returns.

Item 1B. ***Unresolved Staff Comments***

None.

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Item 2. *Properties*

Major Coal Properties

The following is a summary of our major coal producing properties in each region. For information regarding our Coal Reserves and Production as well as other information related to our coal properties, please see Item 1. Business.

Northern Appalachia

Beaver Creek. The Beaver Creek property is located in Grant and Tucker Counties, West Virginia. In 2009, 2.2 million tons were produced from this property. We lease this property to Mettiki Coal, LLC, a subsidiary of Alliance Resource Partners L.P. Coal is produced from an underground longwall mine. It is transported by truck to a preparation plant operated by the lessee. Coal is shipped primarily by truck to the Mount Storm power plant of Dominion Power.

Gatling WV. The Gatling property is located in Mason County, West Virginia. In 2009, 406,000 tons were produced from the property. Coal from this property is mined from an underground mine and transported via belt line to a preparation plant on the property. Clean coal is transported via beltline either directly to American Electric Power or to a barge loading facility.

AFG-Southwest PA. The AFG property is located in Washington County, Pennsylvania. In 2009, 304,000 tons were produced from this property. We lease this property to Conrhein Coal Company, a subsidiary of Consol Energy. Coal is produced from an underground mine and is transported by belt to a preparation plant operated by the lessee. Coal is shipped by both the CSX and Norfolk Southern railways to utility customers, such as American Electric Power and Allegheny Energy.

Gatling OH. The Gatling property is located in Meigs County, Ohio and was acquired in May 2009. From the date of acquisition through the remainder of the year, 277,000 tons were produced from the property. Coal from this property is mined from an underground mine and transported via belt line to a preparation plant on the property. Clean coal is transported via beltline to a barge loading facility, from which it is transported via barge to American Electric Power.

The map on the following page shows the location of our properties in Northern Appalachia.

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Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2009, 4.9 million tons were produced from this property. We primarily lease this property to Alpha Land and Reserves, LLC, a subsidiary of Alpha Natural Resources, Inc. Production comes from both underground and surface mines and is trucked to one of four preparation plants. Coal is shipped via both the CSX and Norfolk Southern railroads to utility and metallurgical customers. Major customers include American Electric Power, Southern Company, Tennessee Valley Authority, VEPCO and U.S. Steel and to various export metallurgical customers.

Lynch. The Lynch property is located in Harlan and Letcher Counties, Kentucky. In 2009, 4.1 million tons were produced from this property. We primarily lease the property to Resource Development, LLC, an independent coal producer. Production comes from both underground and surface mines. Coal is transported by truck to a preparation plant on the property and is shipped primarily on the CSX railroad to utility customers such as Georgia Power and Orlando Utilities.

D.D. Shepard. The D.D. Shepard property is located in Boone County, West Virginia. This property is primarily leased to a subsidiary of Patriot Coal Corp. In 2009, 3.2 million tons were produced from the property. Both steam and metallurgical coal are produced by the lessees from underground and surface mines. Coal is transported from the mines via belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to customers such as American Electric Power and to various export metallurgical customers.

Dingess-Rum. The Dingess-Rum property is located in Logan, Clay and Nicholas Counties, West Virginia. This property is leased to subsidiaries of Massey Energy and Patriot Coal. In 2009, 3.0 million tons were produced from the property. Both steam and metallurgical coal are produced from underground and surface mines and transported by belt or truck to preparation plants on the property. Coal is shipped via the CSX railroad to steam customers such as American Electric Power, Dayton Power and Light, Detroit Edison and to various export metallurgical customers.

VICC/Kentucky Land. The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2009, 2.6 million tons were produced from this property. Coal is produced from a number of lessees from both underground and surface mines. Coal is shipped primarily by truck but also on the CSX and Norfolk Southern railroads to customers such as Southern Company, Tennessee Valley Authority, and American Electric Power.

Lone Mountain. The Lone Mountain property is located in Harlan County, Kentucky. In 2009, 1.8 million tons were produced from this property. We lease the property to Ark Land Company, a subsidiary of Arch Coal, Inc. Production comes from underground mines and is transported primarily by beltline to a preparation plant on adjacent property and shipped on the Norfolk Southern or CSX railroads to utility customers such as Georgia Power and the Tennessee Valley Authority.

Pardee. The Pardee property is located in Letcher County, Kentucky and Wise County Virginia. In 2009, 1.4 million tons were produced from this property. We lease the property to Ark Land Company, a subsidiary of Arch Coal, Inc. Production comes from underground and surface mines and is transported by truck or beltline to a preparation plant on the property and shipped primarily on the Norfolk Southern railroad to utility customers such as Georgia Power and the Tennessee Valley Authority and domestic and export metallurgical customers such as Algoma Steel and Arcelor.

The map on the following page shows the location of our properties in Central Appalachia.

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Southern Appalachia

BLC Properties. The BLC properties are located in Kentucky, Tennessee, and Alabama. In 2009, 2.4 million tons were produced from these properties. We lease these properties to a number of operators including Appolo Fuels Inc., Bell County Coal Corporation and Kopper-Glo Fuels. Production comes from both underground and surface mines and is trucked to preparation plants and loading facilities operated by our lessees. Coal is transported by truck and is shipped via both CSX and Norfolk Southern railroads to utility and industrial customers. Major customers include Southern Company, South Carolina Electric & Gas, and numerous medium and small industrial customers.

Oak Grove. The Oak Grove property is located in Jefferson County, Alabama. In 2009, 858,000 tons were produced from this property. We lease the property to Oak Grove Resources, LLC, a subsidiary of Cliffs Natural Resources, Inc. Production comes from an underground mine and is transported primarily by beltline to a preparation plant. The metallurgical coal is then shipped via railroad and barge to both domestic and export customers.

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The map below shows the location of our properties in Southern Appalachia.

Illinois Basin

Williamson Development. The Williamson Development property is located in Franklin and Williamson Counties, Illinois. The property is under lease to an affiliate of the Cline Group, and in 2009, 5.5 million tons were mined on the property. This production is from a longwall mine. Production is shipped primarily via CN railroad to customers such as Duke and to various export customers.

Sato. The Sato property is located in Jackson County, Illinois. In 2009, 567,000 tons were produced from the property. The property is under lease to Knight Hawk Coal LLC, an independent coal producer. Production is currently from a surface mine, and coal is shipped by truck and railroad to various midwest and southeast utilities.

Macoupin. The Macoupin property is located in Macoupin County, Illinois. We acquired this property in January 2009 and it is leased to an affiliate of the Cline Group. In 2009, 94,000 tons were shipped from the

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property. Production is from an underground mine and is shipped via the Norfolk Southern or Union Pacific railroads or by barge to customers such as Western KY Energy and other midwest utilities.

The map below shows the location of our properties in Illinois Basin.

Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2009, 4.0 million tons were produced from our property. Western Energy Company, a subsidiary of Westmoreland Coal Company, has two coal leases on the property. Western Energy produces coal by surface dragline mining, and the coal is transported by either truck or beltline to the four-unit 2,200-megawatt Colstrip generation station located at the mine mouth and by the Burlington Northern Santa Fe railroad to Minnesota Power. A small amount of coal is transported by truck to other customers.

The map on the following page shows the location of our properties in Northern Powder River Basin.

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Title to Property

Of the approximately 2.1 billion tons of proven and probable coal reserves that we owned or controlled as of December 31, 2009, we owned approximately 99% of the reserves in fee. We lease approximately 2 million tons, or less than 1% of our reserves, from unaffiliated third parties. We believe that we have satisfactory title to all of our mineral properties, but we have not had a qualified title company confirm this belief. Although title to these properties is subject to encumbrances in certain cases, such as customary easements, rights-of-way, interests generally retained in connection with the acquisition of real property, licenses, prior reservations, leases, liens, restrictions and other encumbrances, we believe that none of these burdens will materially detract from the value of our properties or from our interest in them or will materially interfere with their use in the operations of our business.

For most of our properties, the surface, oil and gas and mineral or coal estates are owned by different entities. Some of those entities are our affiliates. State law and regulations in most of the states where we do business require the oil and gas owner to coordinate the location of wells so as to minimize the impact on the intervening coal seams. We do not anticipate that the existence of the severed estates will materially impede development of the minerals on our properties.

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Item 3. *Legal Proceedings*

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, we believe these claims will not have a material effect on our financial position, liquidity or operations.

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

None.

PART II

Item 5. *Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities*

Our common units are listed and traded on the New York Stock Exchange (NYSE) under the symbol NRP . As of February 11, 2010, there were approximately 30,700 beneficial and registered holders of our common units. The computation of the approximate number of unitholders is based upon a broker survey.

The following table sets forth the high and low sales prices per common unit, as reported on the New York Stock Exchange Composite Transaction Tape from January 1, 2008 to December 31, 2009, and the quarterly cash distribution declared and paid with respect to each quarter per common unit.

	Price Range		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2008					
First Quarter	$ 33.99	$ 24.61	$ 0.4950	05/01/2008	05/14/2008
Second Quarter	$ 41.65	$ 28.42	$ 0.5150	08/01/2008	08/14/2008
Third Quarter	$ 41.20	$ 22.75	$ 0.5250	11/03/2008	11/14/2008
Fourth Quarter	$ 25.99	$ 12.66	$ 0.5350	02/05/2009	02/13/2009
2009					
First Quarter	$ 25.00	$ 17.59	$ 0.5400	05/04/2009	05/14/2009
Second Quarter	$ 25.47	$ 20.51	$ 0.5400	08/05/2009	08/14/2009
Third Quarter	$ 23.60	$ 17.00	$ 0.5400	11/05/2009	11/13/2009
Fourth Quarter	$ 24.81	$ 19.50	$ 0.5400	02/05/2010	02/12/2010

Our general partner holds 65% of our incentive distribution rights (IDRs) and the remaining IDRs are held by affiliates of our general partner. The IDRs entitle the holders to incentive distributions if the amount we distribute with respect to any quarter exceeds the specified target levels shown below:

Percentage Allocations of Available Cash from Operating Surplus

	Total Quarterly Distribution Target	Marginal Percentage Interest in Distributions Paid		
	Amount	Unitholders	General Partner	Holders of IDRs
Minimum Quarterly Distribution	$0.25625	98%	2%	
First Target Distribution	$0.25625 up to $0.28125	98%	2%	
Second Target Distribution	above $0.28125 up to $0.33125	85%	2%	13%
Third Target Distribution		75%	2%	23%

	above $0.33125 up to $0.38125			
Thereafter	above $0.38125	50%	2%	48%

Cash Distributions to Partners

	General Partner	Limited Partners	IDRs	Total Distributions
	(In thousands)			
2007 Distributions	$ 2,939	$ 118,858	$ 25,236	$ 147,033
2008 Distributions	3,426	131,080	36,801	171,307
2009 Distributions	3,762	144,766	39,607	188,135

We must distribute all of our cash on hand at the end of each quarter, less cash reserves established by our general partner. We refer to this cash as available cash as that term is defined in our partnership agreement. The amount of available cash may be greater than or less than the minimum quarterly distribution. Provisions of our credit facility and note purchase agreement may restrict our ability to make distributions under certain limited circumstances.

In general, we intend to increase our cash distributions in the future assuming we are able to increase our available cash from operations and through acquisitions, provided there is no adverse change in operations, economic conditions and other factors. However, we cannot guarantee that future distributions will continue at such levels.

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Item 6. *Selected Financial Data*

The following table shows selected historical financial data for Natural Resource Partners L.P. for the periods and as of the dates indicated. We derived the information in the following tables from, and the information should be read together with and is qualified in its entirety by reference to, the historical financial statements and the accompanying notes included in Item 8, Financial Statements and Supplementary Data. These tables should be read together with Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations.

NATURAL RESOURCE PARTNERS L.P.

	For the Years Ended December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
	(In thousands, except per unit and per ton data)				
Income Statement Data:					
Revenues:					
Coal royalties and related revenues	$ 207,138	$ 238,834	$ 177,088	$ 150,791	$ 145,990
Coal processing and transportation	20,190	20,437	8,808	1,452	
Aggregate royalties	5,580	9,119	7,434	538	
Oil and gas royalties	7,520	7,902	4,930	4,220	3,180
Property taxes	11,636	9,800	10,285	5,971	6,516
Other	4,020	5,573	6,440	7,701	3,367
Total revenues	256,084	291,665	214,985	170,673	159,053
Expenses:					
Depreciation, depletion and amortization	60,012	64,254	51,391	29,695	33,730
General and administrative	23,102	13,922	20,048	15,520	12,319
Property, franchise and other taxes	14,996	13,558	13,613	8,122	8,142
Other	3,999	2,924	1,634	1,560	3,392
Total expenses	102,109	94,658	86,686	54,897	57,583
Income from operations	153,975	197,007	128,299	115,776	101,470
Other, net	(39,895)	(27,001)	(25,800)	(13,686)	(9,631)
Net income	$ 114,080	$ 170,006	$ 102,499	$ 102,090	$ 91,839
Balance Sheet Data (at period end):					
Land, equipment, coal and other mineral rights, net	$ 1,405,083	$ 1,174,067	$ 1,222,094	$ 845,531	$ 610,506
Total assets	1,523,590	1,301,340	1,320,031	939,493	684,996
Long-term debt	626,587	478,822	496,057	454,291	221,950
Partners capital	765,226	743,341	744,591	435,687	425,908
Other Data:					
Royalty coal tons produced by lessees	46,848	60,570	57,232	52,092	53,606
	$ 4.20	$ 3.74	$ 2.99	$ 2.84	$ 2.65

Average gross coal royalty revenue per ton										
Aggregate tons produced by lessee		3,269		4,791		5,698		412		
Average gross aggregate royalty revenue per ton	$	1.30	$	1.31	$	1.19	$	1.11		
Basic and diluted net income per limited partner unit	$	1.17	$	1.95	$	1.11	$	1.60	$	1.71
Weighted average number of units outstanding		67,702		64,891		64,505		50,682		50,682
Distributions per limited partner unit	$	2.16	$	2.07	$	1.88	$	1.67	$	1.45

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

The following discussion of the financial condition and results of operations should be read in conjunction with the historical financial statements and notes thereto included elsewhere in this filing. For more detailed information regarding the basis of presentation for the following financial information, see the Notes to the Consolidated Financial Statements.

Executive Overview

Our Business

We engage principally in the business of owning, managing and leasing coal properties in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States. As of December 31, 2009, we owned or controlled approximately 2.1 billion tons of proven and probable coal reserves, of which 54% are low sulfur coal. We also owned approximately 130 million tons of aggregate reserves in Washington, Texas, Arizona and West Virginia. We lease our reserves to experienced mine operators under long-term leases that grant the operators the right to mine and sell our reserves in exchange for royalty payments.

Our revenue and profitability are dependent on our lessees ability to mine and market our reserves. Most of our coal is produced by large companies, many of which are publicly traded, with experienced and professional sales departments. A significant portion of our coal is sold by our lessees under coal supply contracts that have terms of one year or more. In contrast, our aggregate properties are typically mined by regional operators with significant experience and knowledge of the local markets. The aggregates are sold at current market prices, which historically have increased along with the producer price index for sand and gravel at approximately 3.5% per year. Over the long term, both our coal and aggregate royalty revenues are affected by changes in the market for and the market price of the commodities.

In our royalty business, our lessees make payments to us based on the greater of a percentage of the gross sales price or a fixed royalty per ton of coal or aggregates they sell, subject to minimum monthly, quarterly or annual payments. These minimum royalties are generally recoupable over a specified period of time (usually two to five years) if sufficient royalties are generated from production in those future periods. We do not recognize these minimum royalties as revenue until the applicable recoupment period has expired or they are recouped through production. Until recognized as revenue, these minimum royalties are recorded as deferred revenue, a liability on our balance sheet.

In addition to coal and aggregate royalty revenues, we generated approximately 21% of our 2009 revenues from other sources, as compared to 19% in 2008. These other sources include: coal processing and transportation fees; overriding royalties; royalties on oil and gas; wheelage payments; rentals; property tax revenue; minimums received as revenue; and timber.

Our Current Liquidity Position

As of December 31, 2009, we had $272 million in available capacity under our existing credit facility, which does not mature until March 2012, as well as approximately $82.6 million in cash. Following our recent acquisitions of additional reserves at the Blue Star mine in Texas and the Deer Run mine in Illinois in January 2010, we currently have $229 million in available capacity under our credit facility.

In connection with our acquisition of approximately 200 million tons of coal reserves related to the Deer Run mine in Illinois from Colt, LLC in the third quarter of 2009, the holders of our incentive distribution rights agreed to forego approximately $7.35 million in distributions with respect to each of the third and fourth quarters of 2009. In addition, because we amortize substantially all of our long-term debt, we have no need to pay off or refinance any debt obligations other than our regularly scheduled principal payments. For more information regarding this acquisition from Colt, LLC, please see Recent Acquisitions .

Pursuant to the purchase and sale agreement in connection with the Colt acquisition, we expect to fund an additional $205 million over the next two years, of which approximately $125 million is anticipated to be funded over the next 12 months, as the operator achieves various development milestones. We anticipate funding these acquisitions through the use of the available capacity under our credit facility and through the issuance of debt and/or equity in the capital markets. We believe that we have enough liquidity to meet our current capital needs.

Current Results

As of December 31, 2009, our coal and aggregate reserves were subject to 214 leases with 76 lessees. For the year ended December 31, 2009, our lessees produced 50.1 million tons of coal and aggregates, generating $202.2 million in royalty revenues from our properties, and our total revenues were $256.1 million.

As a result of declines in production in 2009, we recorded lower than expected revenues for 2009. The difficult economic environment hurt the aggregates business across the country and impacted demand for electricity, particularly within heavily industrialized regions where coal is the dominant generating fuel. In addition, low prices for natural gas in 2009 caused some utilities to displace coal with natural gas. While we do not have much visibility into the future of the coal markets, several public coal companies have indicated that they are starting to see signs of a recovery, and the cold winter has reduced the stockpiles at the utilities and increased natural gas prices. Because approximately 33% of our coal royalty revenues and 26% of the related production during 2009 were from metallurgical coal, we also felt the effects of the global reduction in demand for steel. Several of the metallurgical coal producers on our properties temporarily ceased production during the second quarter, but gradually started calling miners back to work in the third quarter of the year. We anticipate that metallurgical coal prices should continue to increase over 2010 and expect that during 2010 we will experience gradual improvements similar to the changes we saw in the latter part of 2009.

Even though coal royalty revenues from our Appalachian properties represented 65% of our total revenues in 2009, this percentage has continued to decline as we are diligently working to diversify our holdings by expanding our presence in the Illinois Basin and through additional aggregates acquisitions. Through our relationship with the Cline Group, we expect our Illinois Basin assets to contribute even more significantly to our total revenues in 2010.

Political, Legal and Regulatory Environment

The political, legal and regulatory environment is becoming increasingly difficult for the coal industry. In June 2009, the White House Council on Environmental Quality announced a Memorandum of Understanding among the Environmental Protection Agency, or EPA , Department of Interior, and the U.S. Army Corps of Engineers concerning the permitting and regulation of coal mines in Appalachia. While the Council described this memorandum as an unprecedented step[s] to reduce environmental impacts of mountaintop coal mining, the memorandum broadly applies to all forms of coal mining in Appalachia. The memorandum contemplates both short-term and long-term changes to the process for permitting and regulating coal mines in Appalachia.

These new processes, as yet undefined by EPA, impact only six Appalachian states. In connection with this initiative, the EPA has used its authority to create significant delays in the issuance of new permits and the modification of existing permits. The all-encompassing nature of the changes suggests that implementation of the memorandum will generate continued uncertainty regarding the permitting of coal mines in Appalachia for some time and inevitably will lead, at a minimum, to substantial delays and increased costs.

In addition to the increased oversight of the EPA, the Mine Safety and Health Administration, or MSHA, has increased its involvement in the approval of plans and enforcement of safety issues in connection with mining. MSHA s involvement has increased the cost of mining due to more frequent citations and much higher fines imposed on our lessees as well as the overall cost of regulatory compliance. Combined with the difficult economic environment and the higher costs of mining in general, MSHA s recent increased participation in the mine development process could significantly delay the opening of new mines.

The United States Congress has been considering multiple bills that would regulate domestic carbon dioxide emissions, but no such bill has yet received sufficient Congressional support for passage into law. The existing Clean Air Act is also a possible mechanism for regulating greenhouse gases. In April 2007, the U.S. Supreme Court rendered its decision in *Massachusetts v. EPA*, finding that the EPA has authority under the Clean Air Act to regulate carbon dioxide emissions from automobiles and can decide against regulation only if the EPA determines that carbon dioxide does not significantly contribute to climate change and does not endanger public health or the environment. In response to *Massachusetts v. EPA*, in July 2008, the EPA issued a notice of proposed rulemaking requesting public comment on the regulation of greenhouse gases, or

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GHGs . On October 27, 2009 EPA announced how it will establish thresholds for phasing-in and regulating greenhouse gas emissions under various provisions of the Clean Air Act. Three days later, on October 30, 2009, EPA published a final rule in the Federal Register that requires the reporting of greenhouse gas emissions from all sectors of the American economy, although reporting of emissions from underground coal mines and coal suppliers as originally proposed has been deferred pending further review. On December 15, 2009, EPA published a formal determination that six greenhouse gases, including carbon dioxide and methane, endanger both the public health and welfare of current and future generations. In the same Federal Register rulemaking, EPA found that emission of greenhouse gases from new motor vehicles and their engines contribute to greenhouse gas pollution. Although *Massachusetts v. EPA* did not involve the EPA s authority to regulate greenhouse gas emissions from stationary sources, such as coal-fueled power plants, the decision is likely to impact regulation of stationary sources.

On June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. The purpose of ACESA is to control and reduce emissions of GHGs in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth s atmosphere and other climatic changes. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as coal.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. The President has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could have an adverse effect on demand for our coal.

Distributable Cash Flow

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Because distributable cash flow is a significant liquidity metric that is an indicator of our ability to generate cash flows at a level that can sustain or support an increase in quarterly cash distributions paid to our partners, we view it as the most important measure of our success as a company. Distributable cash flow is also the quantitative standard used in the investment community with respect to publicly traded partnerships.

Our distributable cash flow represents cash flow from operations less actual principal payments and cash reserves set aside for future scheduled principal payments on our senior notes. Although distributable cash flow is a non-GAAP financial measure, we believe it is a useful adjunct to net cash provided by operating activities under GAAP. Distributable cash flow is not a measure of financial performance under GAAP and should not be considered as an alternative to cash flows from operating, investing or financing activities. Distributable cash flow may not be calculated the same for NRP as for other companies. A reconciliation of distributable cash flow to net cash provided by operating activities is set forth below.

Reconciliation of GAAP Net cash provided by operating activities to Non-GAAP Distributable cash flow

	For the Years Ended December 31,		
	2009	**2008**	**2007**

Net cash provided by operating activities	$ 210,669	$ 229,956	$ 168,153
Less scheduled principal payments	(17,235)	(17,234)	(9,350)
Less reserves for future principal payments	(32,235)	(17,235)	(13,388)
Add reserves used for scheduled principal payments	17,235	17,234	9,400
Distributable cash flow	$ 178,434	$ 212,721	$ 154,815

Recent Acquisitions

We are a growth-oriented company and have closed a number of acquisitions over the last several years. Our most recent acquisitions are briefly described below.

AzConAgg. In December 2009, we acquired approximately 230 acres of mineral and surface rights related to sand and gravel reserves in southern Arizona from a local operator for $3.75 million.

Colt. In September 2009, we signed a definitive agreement to acquire approximately 200 million tons of coal reserves related to the Deer Run Mine in Illinois from Colt LLC, an affiliate of the Cline Group, through eight separate transactions for a total purchase price of $255 million. Upon closing of the first transaction, we paid $10.0 million, funded through our credit facility, and acquired approximately 3.3 million tons of reserves associated with the initial production from the mine. In January 2010, we closed the second transaction for $40.0 million, funded through our credit facility, and acquired approximately 19.5 million tons of reserves. Future closings anticipated through 2012 will be associated with completion of certain milestones related to the new mine s construction.

Blue Star. In July 2009, we acquired approximately 121 acres of limestone reserves in Wise County, Texas from Blue Star Materials, LLC for a purchase price of $24 million. As of December 31, 2009, we had funded $21.0 million of the acquisition with cash and borrowings under our credit facility. The remaining payment of $3.0 million was funded in January 2010.

Gatling Ohio. In May 2009, we completed the purchase of the membership interests in two companies from Adena Minerals, LLC, an affiliate of the Cline Group. The companies own 51.5 million tons of coal reserves and infrastructure assets at Cline s Yellowbush Mine located on the Ohio River in Meigs County, Ohio. We issued 4,560,000 common units to Adena Minerals in connection with this acquisition. In addition, the general partner of NRP granted Adena Minerals an additional nine percent interest in the general partner as well as additional incentive distribution rights.

Massey. Jewell Smokeless. In March 2009, we acquired from Lauren Land Company, a subsidiary of Massey Energy, the remaining four-fifths interest in coal reserves located in Buchanan County, Virginia in which we previously held a one-fifth interest. Total consideration for this purchase was $12.5 million.

Macoupin. In January 2009, we acquired approximately 82 million tons of coal reserves and infrastructure assets related to the Shay No. 1 mine in Macoupin County, Illinois for $143.7 million from Macoupin Energy, LLC, an affiliate of the Cline Group.

Coal Properties. In October 2008, we acquired an overriding royalty for $5.5 million from Coal Properties Inc. This overriding royalty agreement is for coal reserves located in the states of Illinois and Kentucky.

Mid-Vol Coal Preparation Plant. In April 2008, we completed construction of a coal preparation plant and coal handling infrastructure under our memorandum of understanding with Taggart Global USA, LLC. The total cost to build the facilities was $12.7 million.

Licking River Preparation Plant. In March 2008, we signed an agreement for the construction of a coal preparation plant facility under our memorandum of understanding with Taggart Global USA, LLC. The cost for the facility, located in eastern Kentucky, was $8.9 million.

Critical Accounting Policies

Coal and Aggregate Royalties. Coal and aggregate royalty revenues are recognized on the basis of tons of mineral sold by our lessees and the corresponding revenue from those sales. Generally, the lessees make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of mineral they sell, subject to minimum annual or quarterly payments.

Coal Processing and Transportation Fees. Coal processing fees are recognized on the basis of tons of coal processed through the facilities by our lessees and the corresponding revenue from those sales. Generally, the lessees of the coal processing facilities make payments to us based on the greater of a percentage of the gross sales price or a fixed price per ton of coal that is processed and sold from the facilities. The coal processing leases are structured in a manner so that the lessees are responsible for operating and maintenance expenses associated with the facilities. Coal transportation fees are recognized on the basis of tons of coal transported over the beltlines. Under the terms of the transportation contracts, we receive a fixed price per ton for all coal transported on the beltlines.

Oil and Gas Royalties. Oil and gas royalties are recognized on the basis of volume of hydrocarbons sold by lessees and the corresponding revenue from those sales. Generally, the lessees make payments based on a percentage of the selling price. Some are subject to minimum annual payments or delay rentals.

Minimum Royalties. Most of our lessees must make minimum annual or quarterly payments which are generally recoupable over certain time periods. These minimum payments are recorded as deferred revenue. The deferred revenue attributable to the minimum payment is recognized as revenues either when the lessee recoups the minimum payment through production or when the period during which the lessee is allowed to recoup the minimum payment expires.

Depreciation and Depletion. We depreciate our plant and equipment on a straight line basis over the estimated useful life of the asset. We deplete mineral properties on a units-of-production basis by lease, based upon minerals mined in relation to the net cost of the mineral properties and estimated proven and probable tonnage in those properties. We estimate proven and probable mineral reserves with the assistance of third-party mining consultants, and we use estimation techniques and recoverability assumptions. We update our estimates of mineral reserves periodically and this may result in material adjustments to mineral reserves and depletion rates that we recognize prospectively. Historical revisions have not been material. Timberlands are stated at cost less depletion. We determine the cost of the timber harvested based on the volume of timber harvested in relation to the amount of estimated net merchantable volume by geographic areas. We estimate our timber inventory using statistical information and data obtained from physical measurements and other information gathering techniques. We update these estimates annually, which may result in adjustments of timber volumes and depletion rates that we recognize prospectively. Changes in these estimates have no effect on our cash flow.

Asset Impairment. If facts and circumstances suggest that a long-lived asset or an intangible asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset will not be recoverable, as determined based on projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value.

Share-Based Payments. We account for awards under our Long-Term Incentive Plan under Financial Accounting Standards Board s (FASB) stock compensation authoritative guidance. This authoritative guidance provides that grants must be accounted for using the fair value method, which requires us to estimate the fair value of the grant and charge or credit the estimated fair value to expense over the service or vesting period of the grant based on fluctuations in value. In addition, this authoritative guidance requires that estimated forfeitures be included in the periodic computation of the fair value of the liability and that the fair value be recalculated at each reporting date over the service or vesting period of the grant.

Recent Accounting Pronouncements

In January 2010, the FASB amended fair value disclosure requirements. This amendment requires a reporting entity to disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers, see Note 9. Fair Value Measurements for the definition of Level 1 and Level 2 measurements. The amendment also requires a reporting entity to present separately information about purchases, sales, issuances, and settlements in the reconciliation for fair value measurements using significant unobservable inputs. This amendment is effective for fiscal years beginning after December 15, 2010 and interim periods within those fiscal years. We do not expect this amendment to have an impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued a new standard amending previous consolidation of variable interest entities guidance. This amended guidance requires an enterprise to perform an analysis to determine whether the enterprise s variable interest or interests give it controlling financial interest in a variable interest entity. This amendment is effective for fiscal years beginning after November 15, 2009 and interim periods within those fiscal years. We do not expect this guidance to have a material impact on the financial statements.

In June 2009, the FASB issued a new standard that establishes the Codification as the source of authoritative U.S. accounting and reporting standards recognized by the FASB for use in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. Rules and interpretive releases of the SEC under authority of federal securities law are also sources of authoritative GAAP for SEC registrants. This standard is effective for interim and annual reporting periods after September 15, 2009. This standard had no impact on our financial position, results of operations or cash flows.

In May 2009, the FASB issued a subsequent events standard, which established general standards of accounting for and disclosure of events that occur subsequent to the balance sheet date but before financial statements are issued. This standard defines (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. Under this standard, a public reporting entity shall evaluate subsequent events through the date the financial statements are issued. We adopted this standard for the quarter ended June 30, 2009. The adoption did not impact the financial position, results of operations or cash flows. As disclosed in Note 15. Subsequent Events, we evaluated events that have occurred subsequent to December 31, 2009 through the time of our filing on February 26, 2010.

On April 9, 2009, the FASB issued authoritative guidance that requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This authoritative guidance also requires those disclosures in summarized financial information at interim reporting periods. This authoritative guidance was effective for interim reporting periods ending after June 15, 2009, and requires that we provide fair value footnote disclosure related to our outstanding debt quarterly but will otherwise not materially impact the financial statements. Fair value measurements are disclosed in Note 9. Fair Value Measurements .

In June 2008, the FASB issued new authoritative guidance determining whether instruments granted in share-based payment transactions are participating securities. This authoritative guidance affects entities that accrue cash dividends on share-based payment awards during the awards service period when the dividends do not need to be returned if the employees forfeit the award. This authoritative guidance requires that all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends participate in undistributed earnings with common shareholders and are considered participating securities. Because the awards are considered participating securities, the issuing entity is required to apply the two-class method of computing basic and diluted earnings per share. The provisions of this authoritative guidance were effective for us on January 1, 2009, but because distributions accrued on our share-based payment awards are subject to forfeiture, the adoption did not impact earnings per unit.

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Results of Operations

Summary of 2009 and 2008 Royalties and Production

	For the Years Ended December 31, 2009	For the Years Ended December 31, 2008	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
Coal royalties				
Appalachia				
Northern	$ 14,959	$ 17,074	$ (2,115)	(12)%
Central	132,543	156,109	(23,566)	(15)%
Southern	19,382	19,839	(457)	(2)%
Total Appalachia	166,884	193,022	(26,138)	(14)%
Illinois Basin	22,019	21,695	324	1%
Northern Powder River Basin	7,718	11,533	(3,815)	(33)%
Total	$ 196,621	$ 226,250	$ (29,629)	(13)%
Production (tons)				
Appalachia				
Northern	4,943	5,799	(856)	(15)%
Central	28,032	35,967	(7,935)	(22)%
Southern	3,233	4,273	(1,040)	(24)%
Total Appalachia	36,208	46,039	(9,831)	(21)%
Illinois Basin	6,656	8,313	(1,657)	(20)%
Northern Powder River Basin	3,984	6,218	(2,234)	(36)%
Total	46,848	60,570	(13,722)	(23)%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 3.03	$ 2.94	$ .09	3%
Central	4.73	4.34	.39	9%
Southern	6.00	4.64	1.36	29%
Total Appalachia	4.61	4.19	.42	10%
Illinois Basin	3.31	2.61	.70	27%
Northern Powder River Basin	1.94	1.85	.09	5%
Combined average gross royalty revenue per ton	$ 4.20	$ 3.74	$ .46	12%
Aggregates				
Royalty revenues	$ 4,260	$ 6,275	$ (2,015)	(32)%
Aggregate Bonus Royalty	$ 1,320	$ 2,844	$ (1,524)	(54)%
Production	3,269	4,791	(1,522)	(32)%
Average gross royalty revenue per ton	$ 1.30	$ 1.31	$ (.01)	(1)%

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Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 77% and 78% of our total revenue for the years ended December 31, 2009 and 2008, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Primarily as result of lower production on our property, coal royalty revenues decreased by $26.1 million in 2009. The decline was the result of some reductions in production in response to the coal markets, a fire at one of the preparation plants on our property, and some mines moving their production onto adjacent property. This reduction in production was partially offset by higher per ton royalties.

Illinois Basin. Coal royalty revenues were nearly constant, being only $324,000 higher in 2009 than 2008, although production was 1.7 million tons lower. One mine finished producing on our property in 2009 and moved to adjacent properties. This loss in production was partially offset by production from our Williamson property, which is at a higher royalty rate per ton and therefore generated more coal royalty revenues. Production also began late in the year from our Macoupin property.

Northern Powder River Basin. The decrease in both coal royalty revenues of $3.8 million and production of 2.2 million tons on our Western Energy property was due to the normal variations that occur due to the checkerboard nature of our ownership.

Aggregates Royalty Revenues and Production

We own aggregate reserves located in Washington, Arizona, Texas and West Virginia. For the years ended December 31, 2009 and 2008, we recorded $5.6 million and $9.1 million, respectively, in royalty revenues from aggregates, and had production of 3.3 million tons and 4.8 million tons for each of these years. Nearly all of this production and revenue is attributable to the aggregate reserves in DuPont, Washington. In 2009 we received a bonus royalty payment of $1.3 million from the Washington reserves compared to a $2.8 million payment in 2008. The reduction in tonnage and royalty is primarily attributed to lower demand caused by the poorer economic conditions in 2009.

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Summary of 2008 and 2007 Royalties and Production

	For The Years Ended December 31, 2008	2007	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
Coal royalties				
Appalachia				
Northern	$ 17,074	$ 16,664	$ 410	2%
Central	156,109	117,820	38,289	32%
Southern	19,839	17,832	2,007	11%
Total Appalachia	193,022	152,316	40,706	27%
Illinois Basin	21,695	7,963	13,732	172%
Northern Powder River Basin	11,533	11,064	469	4%
Total	$ 226,250	$ 171,343	$ 54,907	32%
Production (tons)				
Appalachia				
Northern	5,799	7,270	(1,471)	(20)%
Central	35,967	35,835	132	<1%
Southern	4,273	4,603	(330)	(7)%
Total Appalachia	46,039	47,708	(1,669)	(3)%
Illinois Basin	8,313	3,709	4,604	124%
Northern Powder River Basin	6,218	5,815	403	7%
Total	60,570	57,232	3,338	6%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 2.94	$ 2.29	$ 0.65	28%
Central	4.34	3.29	1.05	32%
Southern	4.64	3.87	.77	20%
Total Appalachia	4.19	3.19	1.00	31%
Illinois Basin	2.61	2.15	.46	21%
Northern Powder River Basin	1.85	1.90	(.05)	(3)%
Combined average gross royalty revenue per ton	$ 3.74	$ 2.99	$ .75	25%
Aggregates				
Royalty revenues	$ 6,275	$ 6,778	$ (503)	(7)%
Aggregate Bonus Royalty	$ 2,844	$ 656	$ 2,188	334%
Production	4,791	5,698	(907)	(16)%
Average gross royalty revenue per ton	$ 1.31	$ 1.19	$ 0.12	10%

Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 78% and 80% of our total revenue for the years ended December 31, 2008 and 2007, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Primarily as result of higher coal prices, coal royalty revenues increased by $40.7 million in 2008, even though production was slightly lower than in 2007. The decline in production was primarily the result of a longwall mine in Northern Appalachia that had a substantial percentage of its production come from adjacent property.

Illinois Basin. Coal royalty revenues were $13.7 million higher in 2008 and production was 4.6 million tons higher. As a result of a full year of operation at our Williamson property, coal royalty revenues attributable to that property were $15.8 million for the year ended December 31, 2008 compared to $2.6 million for 2007. Similarly, production attributable to that property was 5.5 million tons for 2008 compared to 1.0 million tons in 2007.

Northern Powder River Basin. The increase in both coal royalty revenues of $0.5 million and production of 0.4 million tons on our Western Energy property was due to the normal variations that occur due to the checkerboard nature of our ownership.

Aggregates Royalty Revenues and Production

For the years ended December 31, 2008 and 2007, we recorded $6.3 million and $6.8 million, respectively in royalty revenues from aggregates, and had production of 4.8 million tons and 5.7 million tons for each of these years. Nearly all of this production and revenue is attributable to the aggregate reserves in DuPont, Washington. In 2008 we received a bonus royalty payment of $2.8 million compared to a $0.7 million payment in 2007.

Other Operating Results

Coal Processing and Transportation Revenues. We generated $7.7 million, $8.8 million and $4.8 million in processing revenues for the years ended December 31, 2009, 2008 and 2007. We do not operate the preparation plants, but receive a fee for coal processed through them. Similar to our coal royalty structure, the throughput fees are based on a percentage of the ultimate sales price for the coal that is processed through the facilities.

In addition to our preparation plants, we own coal handling and transportation infrastructure in West Virginia, Ohio and Illinois. In contrast to our typical royalty structure, we receive a fixed rate per ton for coal transported over these facilities. For the assets other than our loadout facility at the Shay No. 1 mine in Illinois, we operate coal handling and transportation infrastructure and have subcontracted out that responsibility to third parties. We generated transportation fees from these assets of approximately $12.5 million, $11.7 million and $4.0 million for the years ended December 31, 2009, 2008 and 2007, respectively. Production increased during the last half of 2008 and all of 2009 due to the longwall at our Williamson property coming online in March 2008.

Additional Revenues. In addition to coal royalties, aggregate royalties, coal processing and transportation revenues, we generated approximately 13% of our revenues from other sources for the years ended December 31, 2009, 2008 and 2007. These other sources include: oil and gas royalties, property taxes, minimums recognized, overriding royalties, timber, rentals and wheelage.

Operating costs and expenses. Included in total expenses are:

Depreciation, depletion and amortization of $60.0 million, $64.3 million and $51.4 million for the years ended December 31, 2009, 2008 and 2007, respectively. Excluding a onetime expense of $8.2 million for a terminated lease due to a mine closure, depletion decreased from 2008 as a result of lower total production for 2009, while it remained approximately the same as 2007.

General and administrative expenses of $23.1 million, $13.9 million and $20.0 million for the years ended December 31, 2009, 2008 and 2007, respectively. The change in general and administrative expense is primarily due to accruals under our long-term incentive plan attributable to fluctuations in our unit price.

Property, franchise and other taxes have increased for the year ended December 31, 2009 when compared to 2008 and 2007. This increase reflects higher West Virginia property taxes and Kentucky unmined mineral taxes. A substantial portion of our property taxes is reimbursed to us by our lessees and is reflected as property tax revenue on our statement of income.

Interest Expense. Interest expense was higher for the year ended December 31, 2009 when compared to the years ended December 31, 2008 and 2007 due to additional debt incurred to fund acquisitions and higher interest rates.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

We satisfy our working capital requirements with cash generated from operations. Since our initial public offering, we have financed our property acquisitions with available cash, borrowings under our revolving credit facility, and the issuance of our senior notes and additional units. While our ability to satisfy our debt service obligations and pay distributions to our unitholders depends in large part on our future operating performance, our ability to make acquisitions will depend on prevailing economic conditions in the financial markets as well as the coal industry and other factors, some of which are beyond our control. For a more complete discussion of factors that will affect cash flow we generate from operations, please read Item 1A. Risk Factors . Our capital expenditures, other than for acquisitions, have historically been minimal.

Our credit facility does not expire until 2012, and our credit ratios are within our debt covenants for both our credit facility and our outstanding senior notes. In addition, we are amortizing substantially all of our long-term debt and have no immediate need to refinance. For a more complete discussion of factors that will affect our liquidity, please read Item 1A. Risk Factors . During 2009, we continued to review our banking relationships and our internal policies regarding deposit concentrations with specific attention to effectively managing risk in the current banking environment. Following our second acquisition of reserves at the Deer Run mine and our final payment on the Blue Star reserve acquisition in January 2010, we had $229 million in available capacity under the facility. We also had approximately $83 million of cash available at the end of the year.

Net cash provided by operations for the years ended December 31, 2009, 2008 and 2007 was $210.7 million, $230.0 million and $168.2 million, respectively. A significant portion of our cash provided by operations is generated from coal royalty revenues.

Net cash used in investing activities for the years December 31, 2009, 2008 and 2007 was $119.9 million, $9.8 million and $79.6 million, respectively. In each of those years, substantially all of our investing activities consisted of acquiring coal reserves, plant and equipment and other mineral rights. In 2007, we sold surface acreage in Wise County, Virginia for gross proceeds of $1.4 million.

Net cash used for financing activities for the years ended December 31, 2009, 2008 and 2007 was $98.1 million, $188.5 million and $96.2 million, respectively. We had proceeds from loans of $331.0 million and $285.4 million for the years ended December 31, 2009 and 2007. The proceeds were offset by repayment of credit facility borrowings of $151.0 million and $226.4 million for the years ended December 31, 2009 and 2007, respectively. We did not receive any proceeds from loans for the year ended December 31, 2008. We also made $17.2 million in principal payments on our senior notes for the years ended December 31, 2009 and 2008, respectively, and $9.5 million for the year ended December 31, 2007. Proceeds for the year ended December 31, 2009 were also offset by retirement of purchase obligations related to the purchase of reserves and infrastructure of $72.0 million. We paid distributions of $188.1 million, $171.3 million and $147.0 million for the years ended December 31, 2009, 2008 and 2007, respectively. We made $9.4 million in principal payments on our senior notes in 2007. In 2007, as a part of the Dingess-Rum and Mettiki acquisitions we received a $2.6 million cash contribution from our general partner to maintain its 2% interest.

Contractual Obligations and Commercial Commitments

Long-Term Debt

At December 31, 2009, our debt consisted of:

$28.0 million of our $300 million floating rate revolving credit facility, due March 2012;

$35.0 million of 5.55% senior notes due 2013;

$43.7 million of 4.91% senior notes due 2018;

$150.0 million of 8.38% senior notes due 2019;

$84.6 million of 5.05% senior notes due 2020;

$2.3 million of 5.31% utility local improvement obligation due 2021;

$40.2 million of 5.55% senior notes due 2023;

$225.0 million of 5.82% senior notes due 2024; and

$50.0 million of 8.92% senior notes due 2024.

Other than the 5.55% senior notes due 2013, which have only semi-annual interest payments, all of our senior notes require annual principal payments in addition to semi-annual interest payments. The scheduled principal payments on the 5.82% senior notes due 2024 do not begin until March 2010, the scheduled principal payments on the 8.38% senior notes due 2019 do not begin until March 2013, and the scheduled principal payments on the 8.92% senior notes due 2024 do not begin until March 2014. We also make annual principal and interest payments on the utility local improvement obligation.

Credit Facility. We have a $300 million revolving credit facility, and at December 31, 2009 we had approximately $272 million available to us under the facility. Under an accordion feature in the credit facility, we may request our lenders to increase their aggregate commitment to a maximum of $450 million on the same terms. However, under current market conditions, we cannot be certain that our lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, we may attempt to bring new lenders into the facility, but we cannot make any assurance that any new lenders would elect to participate or that the excess credit capacity will be available to us at all or on the existing terms.

Our obligations under the credit facility are unsecured but are guaranteed by our operating subsidiaries. We may prepay all loans at any time without penalty. Indebtedness under the revolving credit facility bears interest, at our option, at either:

the higher of the federal funds rate plus an applicable margin ranging from 0% to 0.50% or the prime rate as announced by the agent bank; or

at a rate equal to LIBOR plus an applicable margin ranging from 0.45% to 1.50%.

We incur a commitment fee on the unused portion of the revolving credit facility at a rate ranging from 0.10% to 0.30% per annum.

The credit agreement contains covenants requiring us to maintain:

a ratio of consolidated indebtedness to consolidated EBITDDA (as defined in the credit agreement) of 3.75 to 1.0 for the four most recent quarters; provided however, if during one of those quarters we have made an acquisition, then the ratio shall not exceed 4.0 to 1.0 for the quarter in which the acquisition occurred and (1) if the acquisition is in the first half of the quarter, the next two quarters or (2) if the acquisition is in the second half of the quarter, the next three quarters; and

a ratio of consolidated EBITDDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated lease operating expense) of 4.0 to 1.0 for the four most recent quarters.

Senior Notes. NRP Operating LLC issued the senior notes under a note purchase agreement. The senior notes are unsecured but are guaranteed by our operating subsidiaries. We may prepay the senior notes at any time together with a make-whole amount (as defined in the note purchase agreement). If any event of default exists under the note purchase agreement, the noteholders will be able to accelerate the maturity of the senior notes and exercise other rights and remedies.

The senior note purchase agreement contains covenants requiring our operating subsidiary to:

Maintain a ratio of consolidated indebtedness to consolidated EBITDA (as defined in the note purchase agreement) of no more than 4.0 to 1.0 for the four most recent quarters;

not permit debt secured by certain liens and debt of subsidiaries to exceed 10% of consolidated net tangible assets (as defined in the note purchase agreement); and

maintain the ratio of consolidated EBITDA to consolidated fixed charges (consisting of consolidated interest expense and consolidated operating lease expense) at not less than 3.5 to 1.0.

In March 2009, we issued $150 million of 8.38% notes maturing March 25, 2019 and $50 million of 8.92% notes maturing March 2024. These senior notes provide that in the event that our leverage ratio exceeds 3.75 to 1.00 at the end of any fiscal quarter, then in addition to all other interest accruing on these notes, additional interest in the amount of 2.00% per annum shall accrue on the notes for the two succeeding quarters and for as long thereafter as the leverage ratio remains above 3.75 to 1.00.

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2009 (in millions):

	Payments Due by Period						
Contractual Obligations	**Total**	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**
Long-term debt (including current maturities)(1)	$ 945.1	$ 72.8	$ 70.4	$ 96.0	$ 120.8	$ 85.2	$ 499.9
Pending acquisitions(2)	248.0	168.0	65.0	15.0			
Rental lease(3)	5.3	0.5	0.5	0.5	0.5	0.5	2.8
Total	$ 1,198.4	$ 241.3	$ 135.9	$ 111.5	$ 121.3	$ 85.7	$ 502.7

(1) The amounts indicated in the table include principal and interest due on our senior notes, as well as the utility local improvement obligation related to our property in DuPont, Washington. The table includes the $28.0 million outstanding principal balance at December 31, 2009 under our credit facility, which matures in March 2012.

(2) The amounts indicated in the table include $245.0 million related to the future anticipated acquisitions with Colt LLC and $3.0 million due and paid in January 2010 to acquire aggregate reserves from Blue Star Materials, LLC. Future acquisitions from Colt LLC are based upon certain milestones relating to the new mine s construction. Upon each closing we receive title to additional reserves. In January 2010 we funded the 2nd acquisition for approximately $40.0 million.

(3) On January 1, 2009, we entered into a ten year lease agreement for the rental of office space from Western Pocahontas Properties Limited Partnership. The rental obligations from this lease are included in the table above.

Shelf Registration Statement

In addition to our credit facility, on February 27, 2009 we filed an automatically effective shelf registration statement on Form S-3 with the SEC that is available for registered offerings of common units and debt securities. The amounts, prices and timing of the issuance and sale of any equity or debt securities will depend on market conditions, our capital requirements and compliance with our credit facility and senior notes.

Two-for-One Limited Partner Unit Split

On April 18, 2007, we completed a two-for-one split of all of our limited partner units. Accordingly, all unit and per unit amounts reported reflect the split.

Off-Balance Sheet Transactions

We do not have any off-balance sheet arrangements with unconsolidated entities or related parties and accordingly, there are no off-balance sheet risks to our liquidity and capital resources from unconsolidated entities.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on operations for the years ended December 31, 2009, 2008 and 2007.

Environmental

The operations our lessees conduct on our properties are subject to federal and state environmental laws and regulations. As an owner of surface interests in some properties, we may be liable for certain environmental conditions occurring on the surface properties. The terms of substantially all of our coal leases require the lessee to comply with all applicable laws and regulations, including environmental laws and regulations. Lessees post reclamation bonds assuring that reclamation will be completed as required by the relevant permit, and substantially all of the leases require the lessee to indemnify us against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. Because we have no employees, employees of Western Pocahontas Properties Limited Partnership make regular visits to the mines to ensure compliance with lease terms, but the duty to comply with all regulations rests with the lessees. We believe that our lessees will be able to comply with existing regulations and do not expect any lessee s failure to comply with environmental laws and regulations to have a material impact on our financial condition or results of operations. We have neither incurred, nor are aware of, any material environmental charges imposed on us related to our properties for the period ended December 31, 2009. We are not associated with any environmental contamination that may require remediation costs. However, our lessees do conduct reclamation work on the properties under lease to them. Because we are not the permittee of the mines being reclaimed, we are not responsible for the costs associated with these reclamation operations. In addition, West Virginia has established a fund to satisfy any shortfall in reclamation obligations.

Related Party Transactions

Partnership Agreement

Our general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with our partnership agreement, we reimburse our general partner and its affiliates for expenses incurred on our behalf. All direct general and administrative expenses are charged to us as incurred. We also reimburse indirect general and administrative costs, including certain legal, accounting, treasury, information technology, insurance, administration of employee benefits and other corporate services incurred by our general partner and its affiliates. Cost reimbursements due our general partner may be substantial and will reduce our cash available for distribution to unitholders. The reimbursements to our general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation totaled $6.8 million in 2009, $5.6 million in 2008 and $5.0 million in 2007. For additional information, please read Certain Relationships and Related Transactions, and Director Independence Omnibus Agreement.

Transactions with Cline Affiliates

Various companies controlled by Chris Cline lease coal reserves from NRP, and we provide coal transportation services to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest in NRP s general partner and in the incentive distribution rights of NRP, as well as 13,510,072 common units. At December 31, 2009, we had accounts receivable totaling $4.0 million from Cline affiliates. For the years ended December 31, 2009, 2008 and 2007, we had total revenue of $37.4 million, $27.9 million and $7.5 million, respectively, from these companies. In addition, we have received $16.2 million in advance minimum royalty payments that have not been recouped.

Quintana Capital Group GP, Ltd.

Corbin J. Robertson, Jr. is a principal in Quintana Capital Group GP, Ltd., which controls several private equity funds focused on investments in the energy business. In connection with the formation of Quintana Capital, we adopted a formal conflicts policy that establishes the opportunities that will be pursued by NRP and those that will be pursued by Quintana Capital. The governance documents of Quintana Capital s affiliated investment funds reflect the guidelines set forth in NRP s conflicts policy.

A fund controlled by Quintana Capital owns a significant membership interest in Taggart Global USA, LLC, including the right to nominate two members of Taggart s 5-person board of directors. We currently have a memorandum of understanding with Taggart Global pursuant to which the two companies have agreed to jointly pursue the development of coal handling and preparation plants. We will own and lease the plants to Taggart Global, which will design, build and operate the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. To date, we have acquired four facilities under this agreement with Taggart with a total cost of $46.6 million. For the years ended December 31, 2009, 2008 and 2007, we received total revenue of $3.9 million and $5.0 million and $2.7 million, respectively, from Taggart. At December 31, 2009, we had accounts receivable totaling $0.2 million from Taggart.

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In June 2007, a fund controlled by Quintana Capital acquired Kopper-Glo, a small coal mining company that is one of our lessees with operations in Tennessee. For the years ended December 31, 2009, 2008 and 2007, we had total revenue of $1.6 million and $1.4 million and $0.1 million, respectively, from Kopper-Glo, and at December 31, 2009, we had accounts receivable totaling $0.1 million from Kopper-Glo.

Office Building in Huntington, West Virginia

In 2008, Western Pocahontas Properties Limited Partnership completed construction of an office building in Huntington, West Virginia. On January 1, 2009, we began leasing substantially all of two floors of the building from Western Pocahontas at market rates. The terms of the lease were approved by our Conflicts Committee. We pay $0.5 million each year in lease payments.

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

We are exposed to market risk, which includes adverse changes in commodity prices and interest rates.

Commodity Price Risk

We are dependent upon the effective marketing of the coal mined by our lessees. Our lessees sell the coal under various long-term and short-term contracts as well as on the spot market. We estimate that over 80% of our coal is currently sold by our lessees under coal supply contracts that have terms of one year or more. Current conditions in the coal industry may make it difficult for our lessees to extend existing contracts or enter into supply contracts with terms of one year or more. Our lessees failure to negotiate long-term contracts could adversely affect the stability and profitability of our lessees operations and adversely affect our coal royalty revenues. If more coal is sold on the spot market, coal royalty revenues may become more volatile due to fluctuations in spot coal prices.

Interest Rate Risk

Our exposure to changes in interest rates results from our current borrowings under our credit facility, which are subject to variable interest rates based upon LIBOR or the federal funds rate plus an applicable margin. Management monitors interest rates and may enter into interest rate instruments to protect against increased borrowing costs. At December 31, 2009, we had $28 million outstanding in variable interest debt. If interest rates were to increase by 1%, annual interest expense would increase $280,000, assuming the same principal amount remained outstanding during the year.

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Item 8. *Financial Statements and Supplementary Data*

INDEX TO FINANCIAL STATEMENTS

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NATURAL RESOURCE PARTNERS L.P.
CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners of Natural Resource Partners L.P.

We have audited the accompanying consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2009 and 2008, and the related consolidated statements of income, partners capital, and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the 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.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Natural Resource Partners L.P. at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 10 to the consolidated financial statements, the consolidated financial statements have been retroactively adjusted to reflect the application of new accounting standard related to participating securities and earnings per unit.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Natural Resource Partners L.P. s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 26, 2010

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except for unit information)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 82,634	$ 89,928
Accounts receivable, net of allowance for doubtful accounts	27,141	31,883
Accounts receivable affiliates	4,342	1,351
Other	930	934
Total current assets	115,047	124,096
Land	24,343	24,343
Plant and equipment, net	64,267	67,204
Coal and other mineral rights, net	1,151,313	979,692
Intangible assets, net	165,160	102,828
Loan financing costs, net	2,891	2,679
Other assets, net	569	498
Total assets	$ 1,523,590	$ 1,301,340
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 914	$ 861
Accounts payable affiliates	179	365
Obligation related to acquisition	2,969	
Current portion of long-term debt	32,235	17,235
Accrued incentive plan expenses current portion	4,627	3,179
Property, franchise and other taxes payable	6,164	6,122
Accrued interest	10,300	6,419
Total current liabilities	57,388	34,181
Deferred revenue	67,018	40,754
Accrued incentive plan expenses	7,371	4,242
Long-term debt	626,587	478,822
Partners capital:		
Common units outstanding: (69,451,136 in 2009, 64,891,136 in 2008)	747,437	719,341
General partner s interest	13,409	13,579
Holders of incentive distribution rights	4,977	11,069
Accumulated other comprehensive loss	(597)	(648)

Total partners capital	765,226	743,341
Total liabilities and partners capital	$ 1,523,590	$ 1,301,340

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

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NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
	2009	2008	2007
	(In thousands, except per unit data)		
Revenues:			
Coal royalties	$ 196,621	$ 226,250	$ 171,343
Aggregate royalties	5,580	9,119	7,434
Coal processing fees	7,673	8,781	4,824
Transportation fees	12,517	11,656	3,984
Oil and gas royalties	7,520	7,902	4,930
Property taxes	11,636	9,800	10,285
Minimums recognized as revenue	1,266	1,257	1,951
Override royalties	9,251	11,327	3,794
Other	4,020	5,573	6,440
Total revenues	256,084	291,665	214,985
Operating costs and expenses:			
Depreciation, depletion and amortization	60,012	64,254	51,391
General and administrative	23,102	13,922	20,048
Property, franchise and other taxes	14,996	13,558	13,613
Transportation costs	1,611	1,416	298
Coal royalty and override payments	2,388	1,508	1,336
Total operating costs and expenses	102,109	94,658	86,686
Income from operations	153,975	197,007	128,299
Other income (expense)			
Interest expense	(40,108)	(28,356)	(28,690)
Interest income	213	1,355	2,890
Net income	$ 114,080	$ 170,006	$ 102,499
Net income attributable to:			
General partner	$ 1,611	$ 2,602	$ 1,489
Holders of incentive distribution rights	$ 33,515	$ 39,914	$ 28,079
Limited partners	$ 78,954	$ 127,490	$ 72,931
Basic and diluted net income per limited partner unit	$ 1.17	$ 1.95	$ 1.11
Weighted average number of units outstanding	67,702	64,891	64,505

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

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NATURAL RESOURCE PARTNERS L.P.

STATEMENT OF PARTNERS CAPITAL

	Common Units		General Partner	Holders of Incentive Distribution Rights	Accumulated Other Comprehensive Income (Loss)	
	Units	**Amounts**	**Amounts**	**Amounts**		**Total**
			(In thousands, except unit data)			
Balance at December 31, 2006	50,681,064	$ 422,536	$ 8,791	$ 5,111	$ (751)	$ 435,687
Issuance of units for acquisitions	14,210,072	346,319	4,422		&#15	