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

Form 10-K

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

For the fiscal year ended December 31, 2010 or

☐ **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	**35-2164875**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification Number)*
601 Jefferson, Suite 3600 Houston, Texas	**77002**
(Address of principal executive offices)	*(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 ☑ No ☐

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

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

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

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

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

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

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

The aggregate market value of the 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 $1.0 billion on June 30, 2010 based on a price of $23.64 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 February 28, 2011, there were 106,027,836 Common Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE.
None.

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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, managing and leasing mineral properties in the United States. We own coal reserves in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. As of December 31, 2010, we owned or controlled approximately 2.3 billion tons of proven and probable coal reserves and we also owned approximately 228 million tons of aggregate reserves in a number of states across the country. We do not operate any mines, but lease reserves to experienced mine operators under long-term leases that grant the operators the right to mine our 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, in addition to minimum payments.

In 2010, our lessees produced 47.1 million tons of coal from our properties and our coal royalty revenues were $221.8 million. Coal processing fees and coal transportation fees added $9.6 million and $14.6 million in revenue, respectively. In addition, our lessees produced 4.4 million tons of aggregates and our aggregate royalties were $4.2 million.

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.

The senior executives and other officers who manage NRP are employees of Western Pocahontas Properties Limited Partnership and Quintana Minerals Corporation, companies 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.

Royalty Business

Royalty businesses principally own and manage mineral reserves. As an owner of mineral reserves, we typically are not responsible for operating mines, but instead enter into leases with mine operators granting them the right to mine and sell 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.

Under our standard lease, lessees calculate royalty and wheelage payments due us and are required to report tons of coal or aggregates removed or hauled across our property as well as the sales prices of the extracted minerals. 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.

Our royalty revenues are affected by changes in long-term and spot commodity prices, production volumes, 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. The prevailing price for aggregates generally depends on local economic conditions. 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 minerals are 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 production by our lessees due to the weather's negative impact on production and transportation.

Acquisitions

We are a growth-oriented company and have completed 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, 2010, 2009 and 2008. 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,		
	2010	2009	2008	2010	2009	2008
	(In thousands)			($ per ton)		
Area						
Appalachia						
Northern	$ 18,676	$ 14,959	$ 17,074	$3.81	$3.03	$2.94
Central	144,934	132,543	156,109	5.36	4.73	4.34
Southern	19,405	19,382	19,839	6.87	6.00	4.64
Total Appalachia	183,015	166,884	193,022	5.26	4.61	4.19
Illinois Basin	30,210	22,019	21,695	3.90	3.31	2.61
Northern Powder River Basin	8,444	7,718	11,533	1.89	1.94	1.85
Gulf Coast	92	—	—	1.77	—	—
Total	$221,761	$196,621	$226,250	$4.71	$4.20	$3.74

The following table sets forth production data and reserve information for the properties that we owned or controlled for the years ending December 31, 2010, 2009, and 2008. 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, 2010		
	2010	2009	2008	Underground	Surface	Total
	(Tons in thousands)					
Area						
Appalachia						
Northern	4,900	4,943	5,799	498,683	6,440	505,123
Central	27,056	28,032	35,967	1,064,679	233,045	1,297,724
Southern	2,824	3,233	4,273	98,695	25,382	124,077
Total Appalachia	34,780	36,208	46,039	1,662,057	264,867	1,926,924
Illinois Basin	7,753	6,656	8,313	229,056	13,868	242,924
Northern Powder River Basin	4,467	3,984	6,218	—	104,839	104,839
Gulf Coast(1)	52	—	—	—	—	—
Total	47,052	46,848	60,570	1,891,113	383,574	2,274,687

(1) Includes lignite acquired in the BRP acquisition. Due to the number of mineral acres involved in the BRP transaction, we have not completed an analysis of the reserve quantity and quality for each mineral that was acquired. As a result, the reserves held by BRP are not included in the statistical information in this Form 10-K. We plan to complete a review of the BRP reserves by the end of 2011.

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, 2010, approximately 52% 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 2010, approximately 32% of the production and 38% 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, 2010.

Sulfur Content, Typical Quality and Type of Coal

Area	Compliance Coal(1)	Sulfur Content: Low (less than 1.0%)	Sulfur Content: Medium (1.0% to 1.5%)	Sulfur Content: High (greater than 1.5%)	Total	Typical Quality: Heat Content (Btu per pound)	Typical Quality: Sulfur (%)	Type of Coal: Steam	Type of Coal: Metallurgical(2)
	(Tons in thousands)						(Tons in thousands)		
Appalachia									
Northern	42,681	51,257	23,929	429,937	505,123	12,874	2.73	495,561	9,562
Central	659,117	926,864	318,798	52,062	1,297,724	13,269	0.89	894,702	403,022
Southern	86,195	92,301	28,089	3,687	124,077	13,504	0.82	80,536	43,541
Total Appalachia	787,993	1,070,422	370,816	485,686	1,926,924		1.36	1,470,799	456,125
Illinois Basin	—	—	2,686	240,238	242,924	11,531	3.02	242,924	—
Northern Powder River Basin	—	104,839	—	—	104,839	8,800	0.65	104,839	—
Gulf Coast(3)	—	—	—	—	—	—	—	—	—
Total	787,993	1,175,261	373,502	725,924	2,274,687			1,818,562	456,125

(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.

(3) Includes lignite acquired in the BRP acquisition. Due to the number of mineral acres involved in the BRP transaction, we have not completed an analysis of the reserve quantity and quality for each mineral that was acquired. As a result, the reserves held by BRP are not included in the statistical information in this Form 10-K. We plan to complete a review of the BRP reserves by the end of 2011.

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 most acquisitions, we have either commissioned new studies or relied on recent reserve studies completed 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 $9.6 million in coal processing revenues for 2010.

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, 2010, we recognized $14.6 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 228 million tons of aggregate reserves located in a number of states across the country. During 2010, our lessees produced 4.4 million tons of aggregates, and our aggregate royalties were $4.2 million.

Oil and Gas Properties

In 2010, we derived approximately 3% of our total revenues from oil and gas royalties in various states.

Significant Customers

In 2010, we had total revenues of $62.4 million from The Cline Group, $42.9 million from Massey Energy Company and $36.2 million from Alpha Natural Resources. Each of these lessees represented more than 10% of our total revenues. The loss of one or all 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 recently undergone significant consolidation. 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 technologies 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 March 2005, the EPA issued the final Clean Air Interstate Rule (or CAIR), which would permanently cap nitrogen oxide and sulfur dioxide emissions in 28 eastern states and Washington, D.C. CAIR required 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. Since a majority of controls required by the CAIR have been installed, 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 Court of Appeals for the D.C. Circuit vacated the CAIR on July 11, 2008. The vacatur caused significant uncertainty regarding state implementing regulations that were based on the CAIR. Upon request for reconsideration, the Court on December 23, 2008, revised its remedy to a remand to EPA without providing a response deadline. The EPA proposed a revised rule on August 2, 2010, and received thousands of comments on the proposal. The rulemaking is expected to be finalized in July of 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 to be lieu of source-specific “maximum achievable control technology”-based limits on hazardous air pollutant (“HAP”) emissions, including mercury, from such sources. The CAMR was vacated in early 2008 by the Court of Appeals for the D.C. Circuit. EPA is in the process of developing MACT standards, and is now under a court order to propose those rules by March 2011 and take final action on that proposal by November 2011. The limits imposed by those rules, if adopted, may limit demand for or otherwise restrict sales of our lessors’ coal, which would reduce royalty revenues.

Other continued tightening of the already stringent regulation of emissions is likely, such as EPA’s revision to the national ambient air quality standard for sulfur dioxide finalized June 22, 2010, and a similar proposal announced for ozone on January 6, 2010 but now expected to be revised no earlier than July of 2011. As a result of these and other tightening of ambient air quality standards, some states will be required to amend their existing state implementation plans to attain and maintain compliance with the new air quality standards. These plan revisions may call for significant additional emission control at coal-fueled power plants.

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, which could trigger Federal plan implementation. EPA has taken no enforcement action against states to finalize implementation plans. Nonetheless, 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.

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 December 2009, the EPA determined that emissions of carbon dioxide, methane, and other greenhouse gases, or “GHGs,” present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Legal challenges to these findings have been asserted, and Congress is considering legislation to delay or repeal EPA’s actions, but we cannot predict the outcome of these efforts. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, including coal-fired electric power plants, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including coal-fired electric power plants, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. As a result of revisions to its preconstruction permitting rules that became fully effective on January 2, 2011, EPA is now requiring new sources, including coal-fired power plants, to undergo control technology reviews for GHGs (predominately carbon dioxide) as a condition of permit issuance. These reviews may impose limits on GHG emissions, or otherwise be used to compel consideration of alternatives fuels and generation systems, as well as increase litigation risk for — and so discourage development of — coal-fired power plants.

In addition, EPA is under a consent decree by which it must propose by July 2011 and take final action by May 2012 on "new source performance standards" to govern GHG emissions from electric generating units, certainly including those fired by coal. The decree also represents EPA's agreement to consider adopting a GHG limitation program governing existing sources, as well, which EPA may attempt to use to establish a cap-and-trade-like system on emissions of power plants' GHG emissions.

Other pending cases regarding GHGs may affect the market for coal. For example, in *AEP v. Connecticut*, the Second Circuit Court of Appeals held that States and private plaintiffs may maintain actions under federal common law alleging that five electric utilities have created a "public nuisance" by contributing to global warming, and may seek injunctive relief capping the utilities' CO_2 emissions at judicially-determined levels. However, the Supreme Court granted certiorari in December 2010 in this case, and argument has not yet been scheduled. An adverse outcome for the defendants in this case or other similar cases could cause additional similar litigation and could adversely affect the demand for our coal.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, primarily through GHG cap and trade programs. Most proposed cap and trade programs work by requiring major sources of emissions, such as coal-fired electric power plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

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. 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 create two permitting programs for our lessees: the NPDES program for regulating the concentrations of pollutants in discharges of waste and storm water; and the § 404 program administered by the Army Corps of Engineers for regulating the placement of the overburden and fill material into waters, including wetlands. 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 used to obtain "general" permits from the Corps of Engineers authorizing the construction of valley fills for the disposal of overburden from mining operations. These general permits, known as Nationwide Permit 21 permits, provided a streamlined permit mechanism, but are now no longer available for surface mining operations. The Corps rescinded the Nationwide Permit 21 permit in March 2009.

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. Theoretically, that ruling should have eased a backlog of individual permit applications. However, starting in 2009, EPA put in place a series of policies for mines in central Appalachia which have had the effect of slowing the issuance of both § 404 fill permits by the Corps and NPDES permits by State agencies. These policies, among other things, seek to impose limits on a specific conductance (conductivity) and sulfate at levels which can be unachievable absent treatment at many mines. The technologies available to treat conductivity and/or sulfate are expensive and may be impracticable at all but the largest underground mines. These policies are the subject to challenge in federal court in Washington, D.C. in *National Mining Association (NMA) v. Jackson.* That Court recently denied a request by NMA for a preliminary injunction after concluding that industry had not shown sufficient concrete harm to warrant the injunction. However, the Court rejected EPA's motion to dismiss the complaint and determined that NMA is likely to prevail on its claims that EPA's policies constitute unlawful rulemaking and fill outside of EPA's statutory authority.

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 appealed this decision to the Fourth Circuit. By ruling of November 8, 2010, the Fourth Circuit affirmed the district court's opinion, and we understand WVDEP is now applying for NPDES permits at bond forfeiture sites. That ruling will have the effect of increasing the monies drawn by WVDEP from the SRF.

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 77 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.

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 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.

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 and enforcement policy related to 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.

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 2010, approximately 32% of the coal production and 38% 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 adoption of climate change legislation or regulations restricting emissions of "greenhouse gases" could result in reduced demand for our coal.

In December 2009, the U.S. Environmental Protection Agency, or "EPA," determined that emissions of carbon dioxide, methane and other greenhouse gases, or "GHGs," present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Legal challenges to these findings have been asserted, and Congress is considering legislation to delay or repeal EPA's actions, but we cannot predict the outcome of these efforts. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act. The EPA recently adopted various rules under the Clean Air Act that have the effect of requiring permits for new and modified sources of greenhouse gas emissions. The principal effect of these rules will be to require proposed projects to build or modify certain large stationary sources, including coal-fired electric power plants, to undergo "best available control technology reviews" for greenhouse gases, effective January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, including coal-fired electric power plants, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. On December 21, 2010, EPA signed a consent decree in which it agreed to propose by July 26, 2011 additional rules to limit GHG emissions from new and existing electric generating units, and to take final action on that proposal by July 26, 2012. If adopted, the new source rules would apply to all affected sources on which construction commenced after the proposal date.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases, and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as coal-fired electric power plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require consumers of coal to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the coal we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that the Earth's climate is constantly changing, and climate change can have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. In addition, several lawsuits have been filed in which the plaintiffs assert common law causes of action, including that emissions of GHGs constitute a nuisance against certain entities, including in one of the cases, Natural Resource Partners. Although the case against Natural Resource Partners has been dismissed, another case involving similar issues but in which Natural Resource Partners is not a defendant, *American Electric Power v. Connecticut*, will be reviewed and decided by the U.S. Supreme Court in 2011. An adverse outcome for the defendants in this case 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. In 2009, the EPA announced an intent to increase enforcement of violations of the Clean Water Act under its Clean Water Act Action Plan. In 2010, pursuant to the Clean Water Action Plan, EPA developed guidance that may result in increased scrutiny and enforcement relating to discharges of pollutants governed by National Pollution Discharge Elimination, or "NPDES," permits, or their state equivalent. EPA may develop further guidance and programs under the Clean Water Action Plan that may result in increased scrutiny and enforcement of actions covered by the Clean Water Act. Such increased scrutiny and enforcement of our lessees' operations may result in increased compliance costs, revisions to permits, or changes in operations, which could decrease our royalty revenues.

As a result of ongoing consolidation in the coal industry and our partnership with the Cline Group, we derive a greater percentage of our revenues from a smaller number of lessees.

In 2010, we derived over 20% of our revenues from the Cline Group, 14% from Massey Energy Company and 12% from Alpha Natural Resources. Cline's Williamson mine alone was responsible for approximately 10% of our revenues in 2010. As a result, we have significant concentration of revenues with those lessees, although in most cases, with the exception of Williamson, the exposure is spread out over a number of different mining operations and leases. In addition, Alpha and Massey recently announced an agreement to merge their two companies, subject to the usual approvals and conditions, including shareholder approval. If our lessees merge or otherwise consolidate, or if we acquire additional reserves from existing lessees, then our revenues could become more dependent on fewer mining companies. If issues occur at those companies that impact their ability to pay us royalties, our royalty revenues and ability to make future distributions would be adversely affected.

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.

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, debt, the use of commercial paper or new equity. 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.

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 generally do not 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 capital and 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 partner may not be removed except upon the vote of the holders of at least 66⅔% 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.

In addition, 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 was proposed in a prior session of Congress that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have applied to us as proposed, it could be reintroduced or 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.

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

Because our unitholders are treated as partners to whom we allocate taxable income that could be different in amount than the cash we distribute, you are 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 tax rate, and non-U.S. persons will be required to file U.S. federal income 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.

To maintain the uniformity of the economic and tax characteristics of our common units, we have adopted 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, the U.S. Treasury Department 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. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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.

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. The IRS recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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

Changes to U.S. federal income tax laws have been proposed in a prior session of Congress that would eliminate certain key U.S. federal income tax preferences relating to coal exploration and development. These changes include, but are not limited to (i) repealing capital gains treatment of coal and lignite royalties, (ii) eliminating current deductions and 60-month amortization for exploration and development costs relating to coal and other hard mineral fossil fuels, (iii) repealing the percentage depletion allowance with respect to coal properties, and (iv) excluding 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. If enacted, these changes would limit or 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 are 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 are likely subject to other taxes, including 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 are likely required to file 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, state and local tax returns.

Item 1B. *Unresolved Staff Comments*

None.

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."

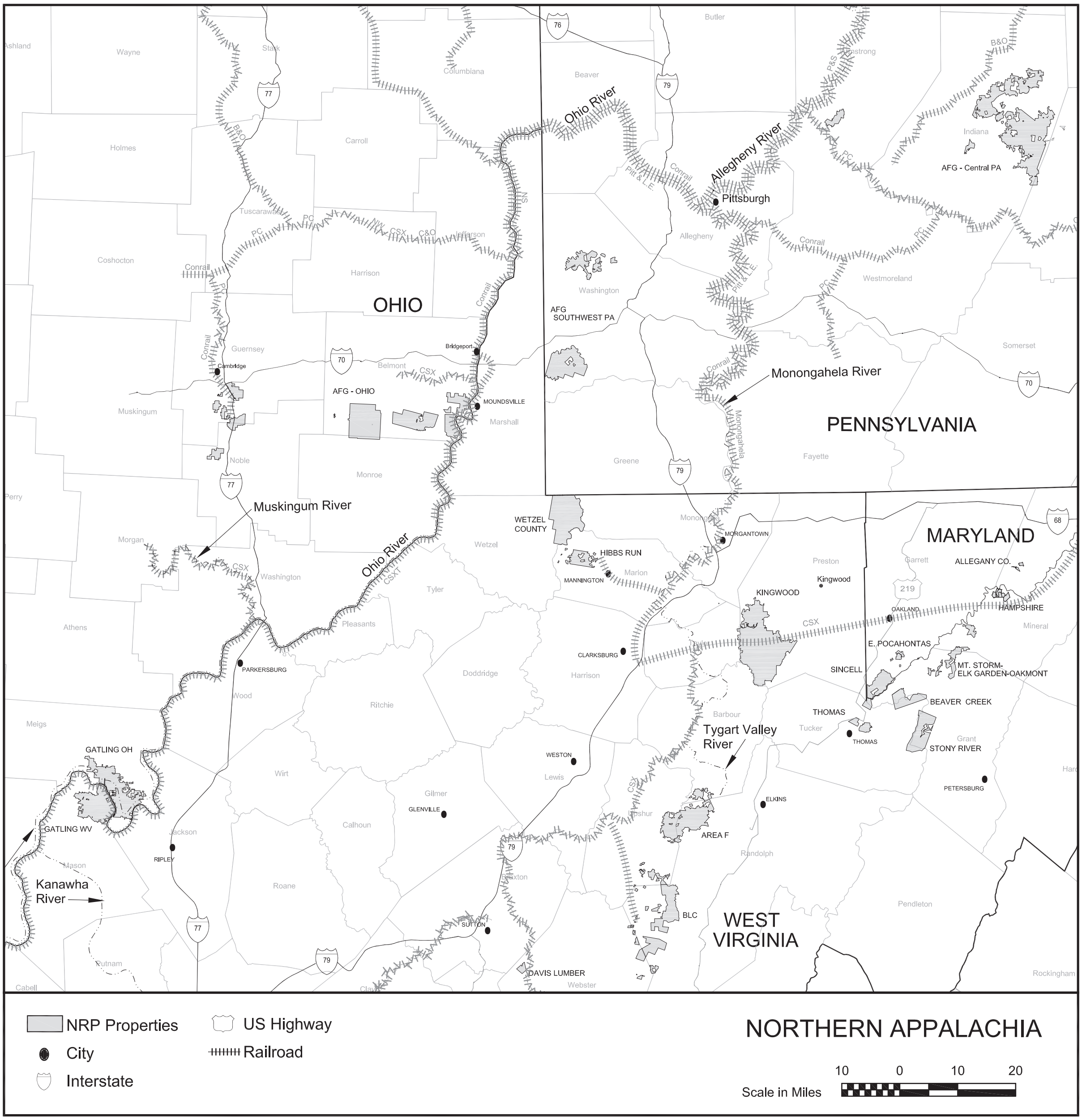
Northern Appalachia

Beaver Creek. The Beaver Creek property is located in Grant and Tucker Counties, West Virginia. In 2010, 2.5 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 and to various export customers.

Gatling Ohio. The Gatling property is located in Meigs County, Ohio. In 2010, 715,000 tons were produced from the property. We lease this property to an affiliate of the Cline Group. 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 mainly to Allegheny Energy and American Electric Power.

Allegany County, Maryland. In 2010, 419,000 tons were produced from the property. We lease this property to Vindex Energy, a subsidiary of ICG. Coal from this property is produced from a surface mine. The raw coal is trucked to the Warrior plant of Allegheny Energy.

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



Central Appalachia

VICC/Alpha. The VICC/Alpha property is located in Wise, Dickenson, Russell and Buchanan Counties, Virginia. In 2010, 4.7 million tons were produced from this property. We primarily lease this property to a subsidiary of Alpha Natural Resources. 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 2010, 4.6 million tons were produced from this property. We primarily lease the property to a subsidiary of Massey Energy. 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. *VICC/Kentucky Land.* The VICC/Kentucky Land property is located primarily in Perry, Leslie and Pike Counties, Kentucky. In 2010, 2.8 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.

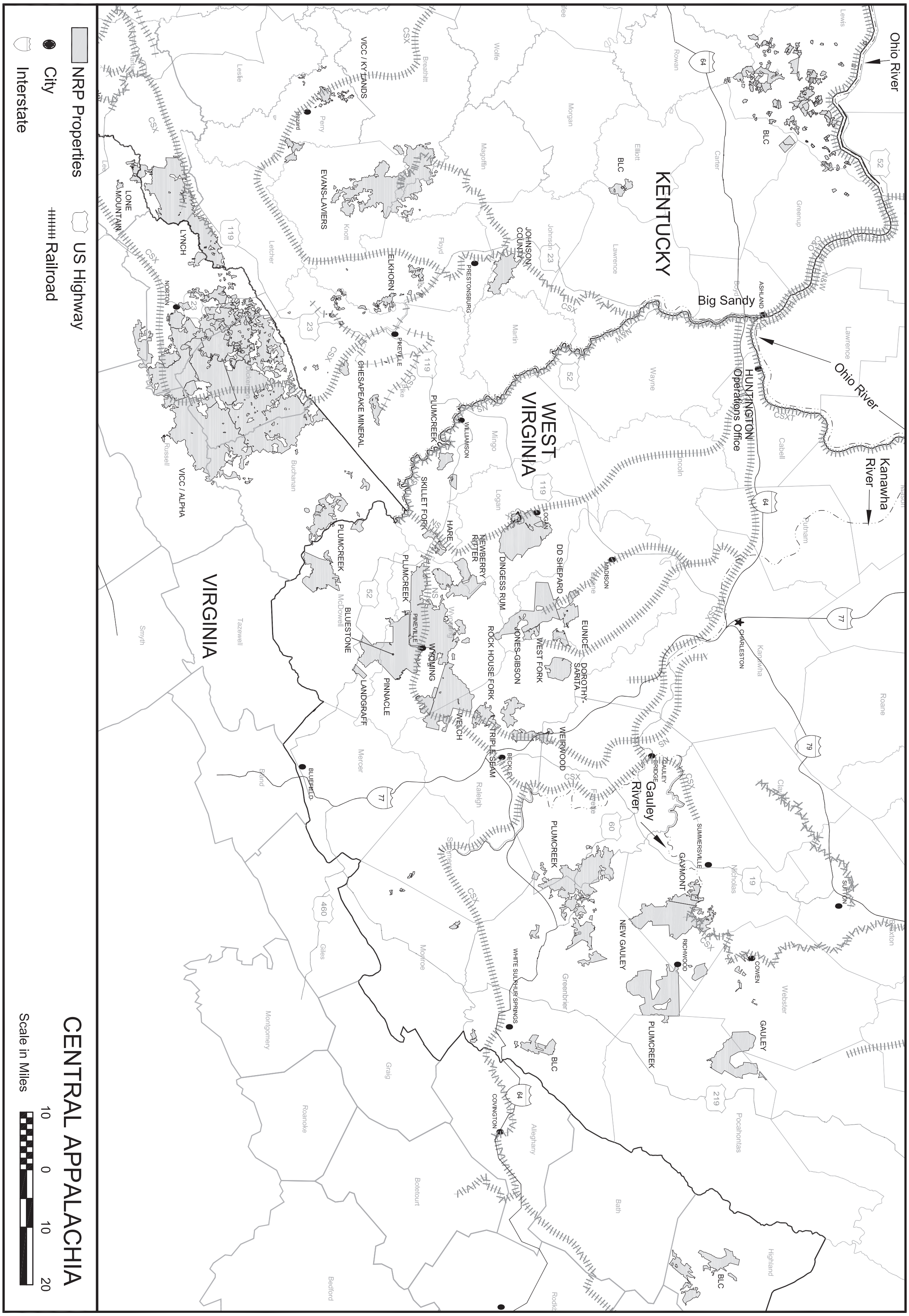
Lone Mountain. The Lone Mountain property is located in Harlan County, Kentucky. In 2010, 2.1 million tons were produced from this property. We lease the property to a subsidiary of Arch Coal, Inc. Production comes from underground mines and is transported primarily by beltline to a preparation plant on adjacent property and shipped on the Norfolk Southern or CSX railroads to utility customers such as Georgia Power and the Tennessee Valley Authority.

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 2010, 1.8 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 various domestic and export metallurgical customers.

Pardee. The Pardee property is located in Letcher County, Kentucky and Wise County Virginia. In 2010, 1.3 million tons were produced from this property. We lease the property to 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.

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 2010, 1.2 million tons were produced from the property. Both steam and metallurgical coal are produced from underground and surface mines and has been historically 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. During 2010, however, due to a fire at the Bandmill preparation plant, the coal that was produced from the property for most of the year was trucked to a remote preparation plant and then shipped via rail to customers. The preparation plant was rebuilt, renamed the Zigmond plant, and resumed operation in late 2010.

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

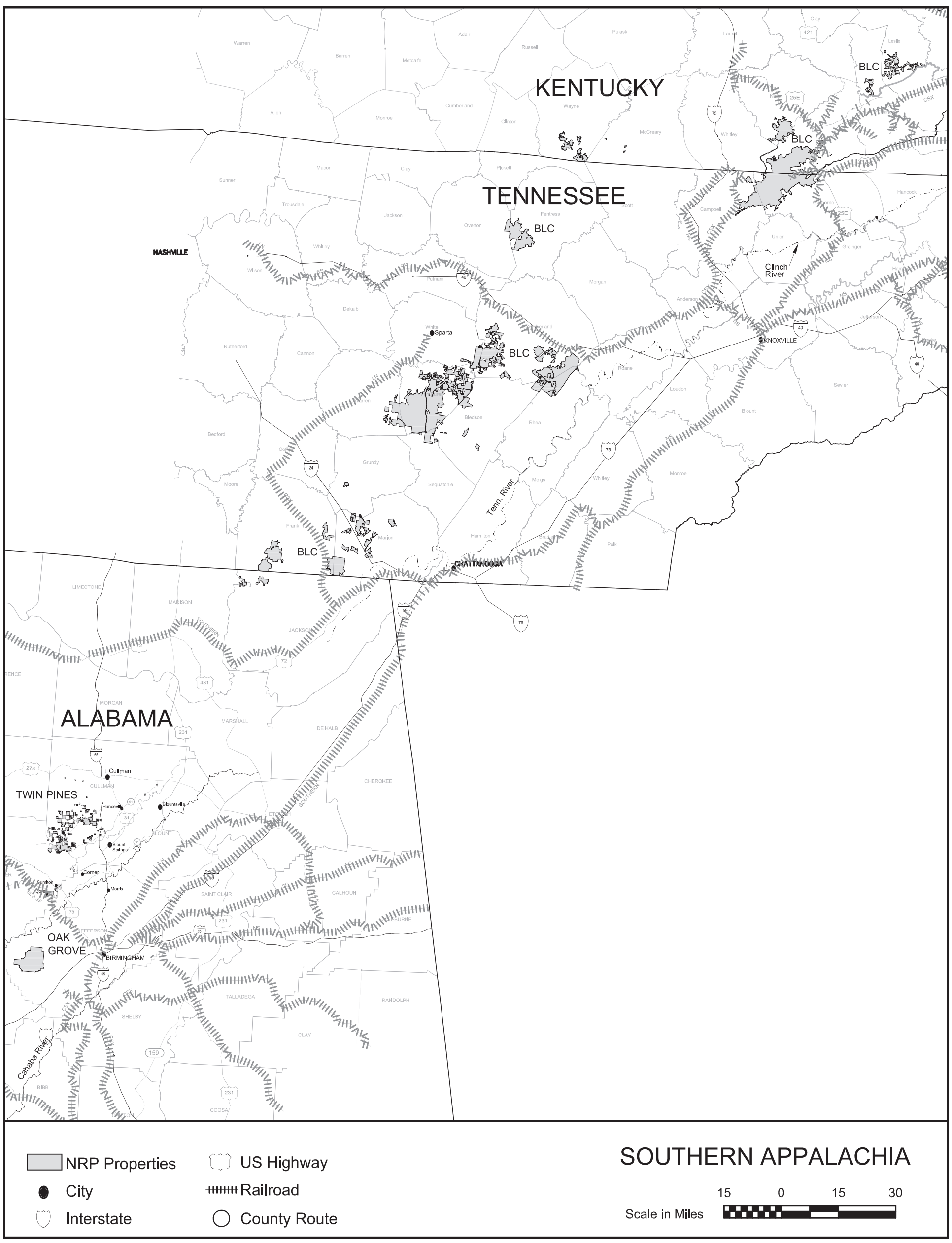

CENTRAL APPALACHIA
Scale in Miles
10 0 10 20
NRP Properties
City
Interstate
US Highway
Railroad
KENTUCKY
WEST VIRGINIA
VIRGINIA
Ohio River
Ohio River
Big Sandy
HUNTINGTON Operations Office
Kanawha River
Gauley River
BLC
BLC
BLC
BLC
VICC / KY LANDS
EVANS-LAVIERS
LONE MOUNTAIN
LYNCH
NORTON
VICC / ALPHA
JOHNSON COUNTY
ELKHORN
PRESTONSBURG
PIKEVILLE
CHESAPEAKE MINERAL
PLUMCREEK
WILLIAMSON
SKILLET FORK
HARE
NEWBERRY RITTER
DINGESS RUM
DD SHEPARD
LOGAN
MADISON
EUNICE
DOROTHY-SARITA
WEST FORK
JONES-GIBSON
ROCK HOUSE FORK
PLUMCREEK
PLUMCREEK
BLUESTONE
PINEVILLE
WYOMING
PINNACLE
LANDGRAFF
WELCH
TRIPLE SEAM
BECKLEY
WEIRWOOD
ASHLAND
CHARLESTON
BLUEFIELD
GAULEY BRIDGE
SUMMERSVILLE
GAYMONT
PLUMCREEK
NEW GAULEY
RICHWOOD
COWEN
SUTTON
PLUMCREEK
GAULEY
WHITE SULPHUR SPRINGS
COVINGTON
CSX
NS

Southern Appalachia

BLC Properties. The BLC properties are located in Kentucky and Tennessee. In 2010, 1.7 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 2010, 1.1 million tons were produced from this property. We lease the property to 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.

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



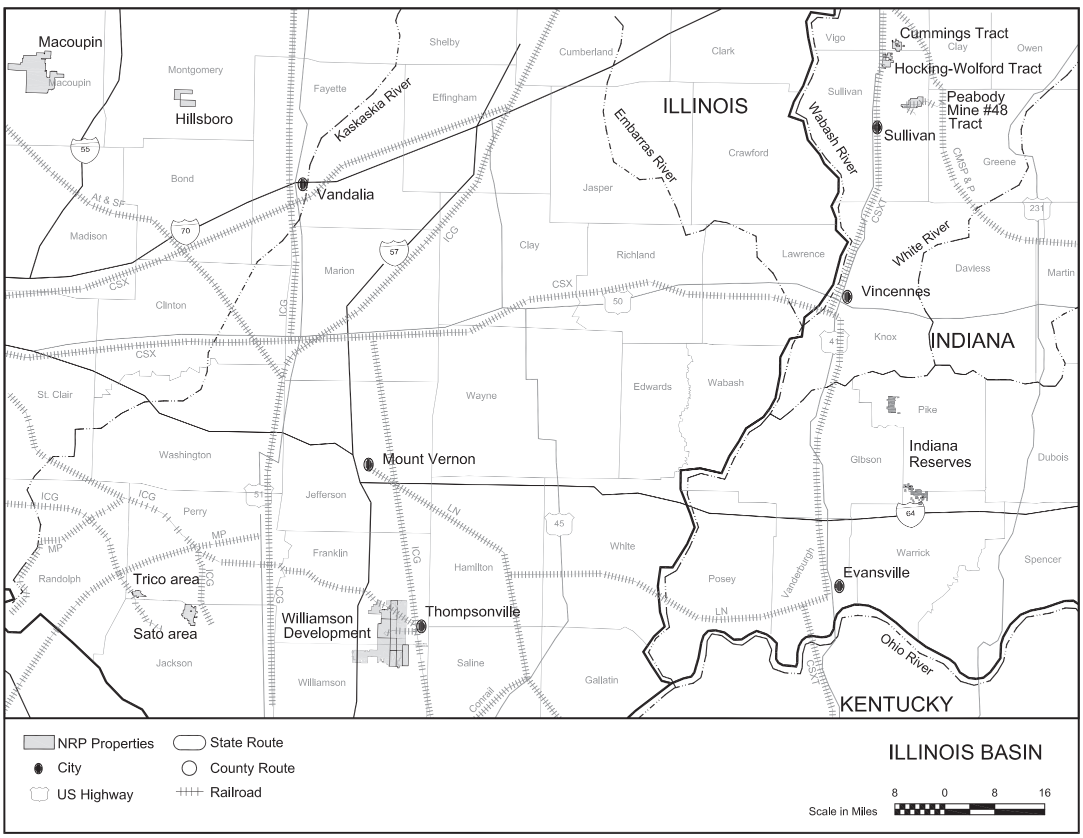
Illinois Basin

Williamson. The Williamson property is located in Franklin and Williamson Counties, Illinois. The property is under lease to an affiliate of the Cline Group, and in 2010, 5.7 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.

Macoupin. The Macoupin property is located in Macoupin County, Illinois. The property is under lease to an affiliate of the Cline Group, and in 2010, 791,000 tons were shipped from the 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 or loaded into barges for shipment to export customers.

Sato. The Sato property is located in Jackson County, Illinois. In 2010, 627,000 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.

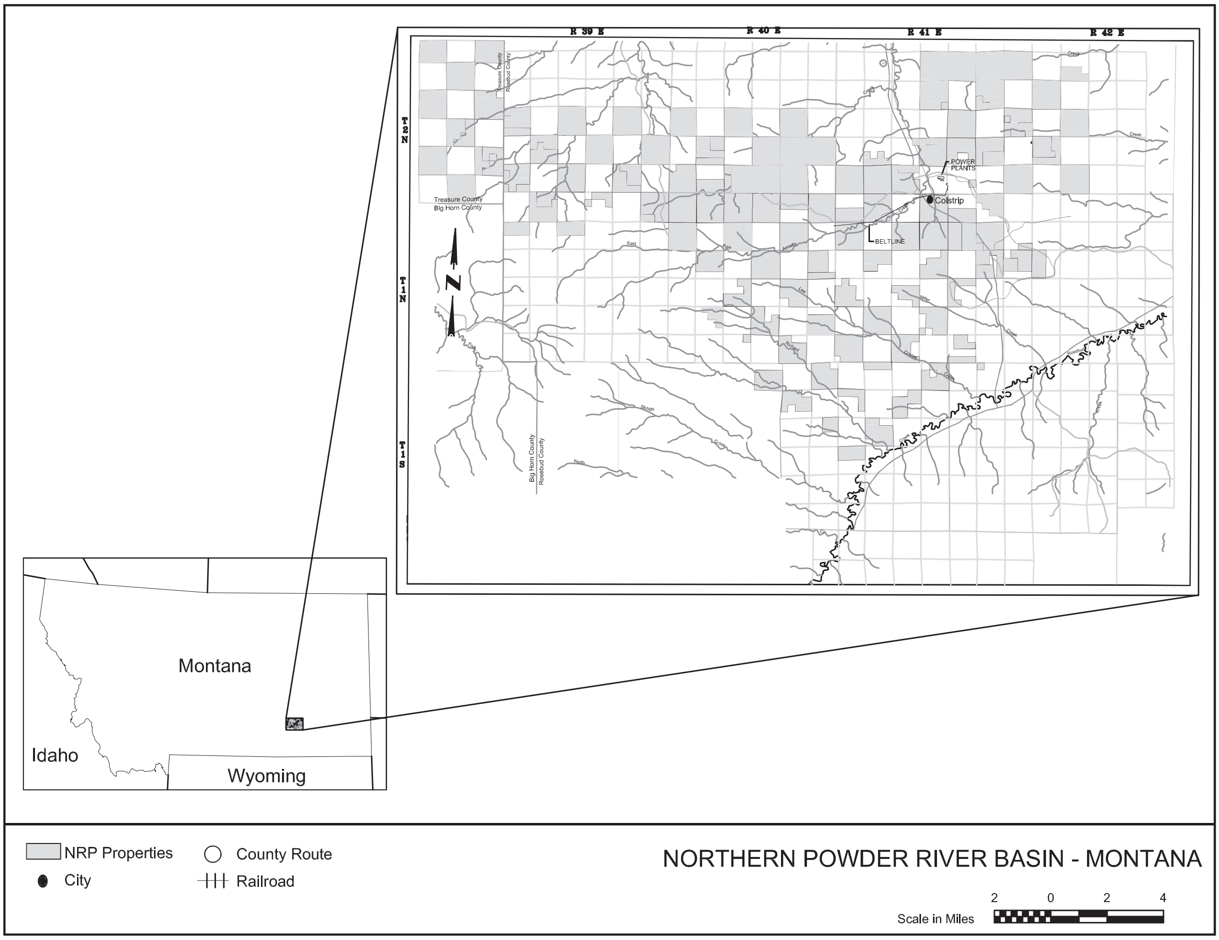
The map below shows the location of our properties in Illinois Basin.



Northern Powder River Basin

Western Energy. The Western Energy property is located in Rosebud and Treasure Counties, Montana. In 2010, 4.5 million tons were produced from our property. A subsidiary of Westmoreland Coal Company has two coal leases on the property. Coal is produced 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 below shows the location of our properties in Northern Powder River Basin.



BRP Properties

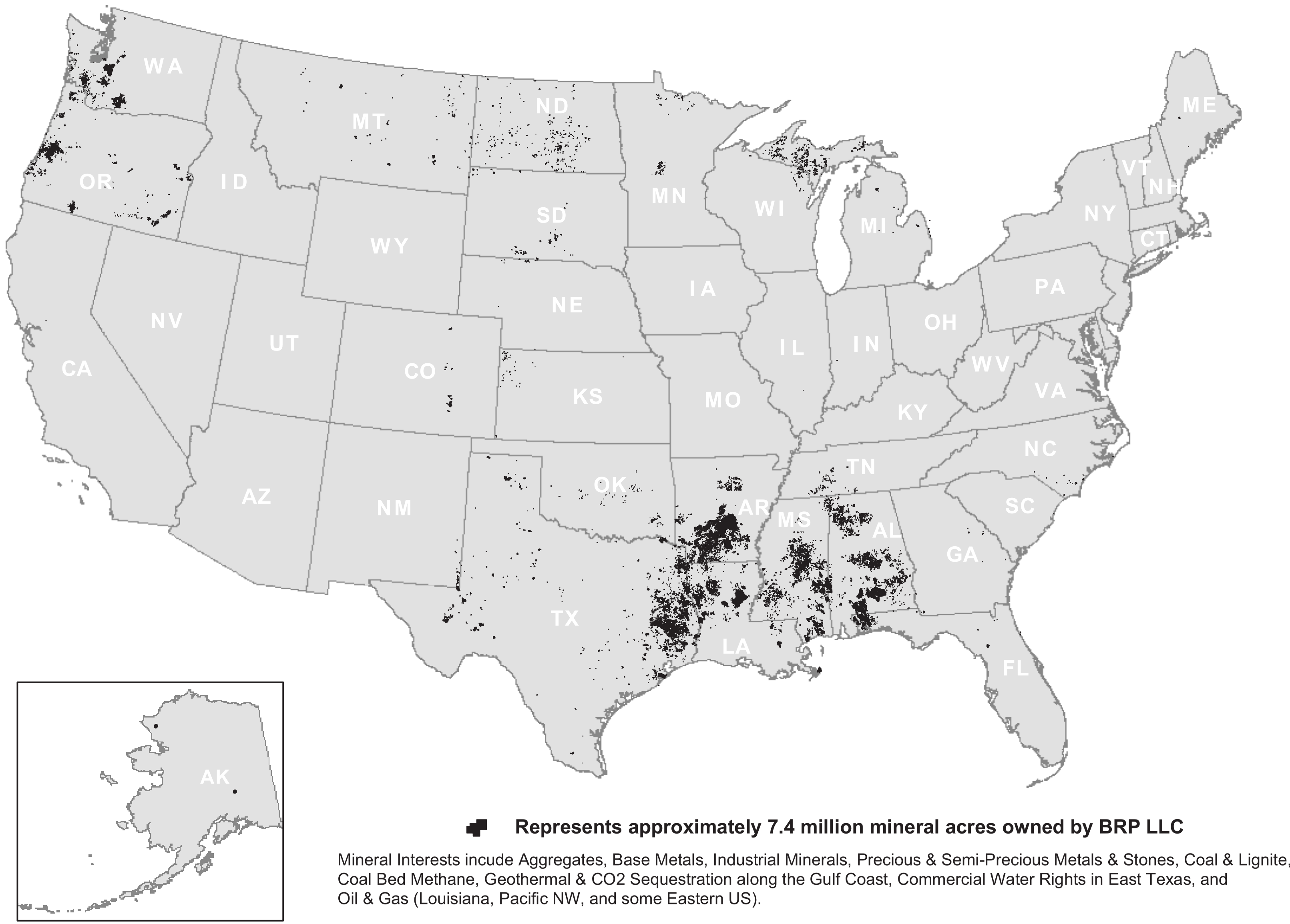
In June 2010, we and International Paper formed BRP. As of December 31, 2010, BRP had acquired, in several stages, approximately 7.35 million mineral acres in 29 states from International Paper. While the vast majority of the 7.35 million acres remain largely undeveloped and underexplored, BRP currently holds 81 revenue generating leases. In addition, a significant number of mineral prospects and deposits with yet undetermined commercial potential have been identified through a variety of efforts including exploration drilling, coring, drill logs, electric logs, inferences derived from published information, geological reports, geological maps, in-house efforts and consulting investigations. These prospects and deposits are not necessarily near-term commercial opportunities due to a variety of factors such as location, market, economic and production uncertainties, but have long-term development potential.

BRP's assets include approximately 300,000 gross acres of oil and gas mineral rights in Louisiana, of which over 60,000 acres were under lease as of December 31, 2010. In addition, BRP holds a gross production royalty interest on approximately 17,000 mineral acres currently under lease in Louisiana. The remaining oil and gas mineral acreage in Louisiana is not leased, but a significant number of acres are in areas with development potential.

As of December 31, 2010, BRP owned nearly 246,000 gross mineral acres of primarily lignite coal rights in the Gulf Coast region, of which approximately 5,000 acres are leased under three separate leases in Louisiana and Alabama. In addition to the coal rights, BRP held aggregate reserves, including limestone, granite, clay, and sand and gravel reserves, under lease in seven states.

Other mineral rights held by BRP as of December 31, 2010 included coalbed methane rights in four Gulf Coast states, metals rights in three states, approximately 450,000 acres of water rights in East Texas, geothermal rights and royalty interests in the Gulf Coast and Pacific Northwest and carbon sequestration rights primarily in the Gulf Coast region.

The map on the following page illustrates the location of BRP's current mineral rights.


WA
OR
CA
ID
NV
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WY
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NM
ND
SD
NE
KS
OK
TX
MN
IA
MO
AR
LA
WI
IL
MS
MI
IN
KY
TN
AL
OH
WV
VA
NC
SC
GA
FL
PA
NY
VT
NH
ME
CT
AK
Represents approximately 7.4 million mineral acres owned by BRP LLC
Mineral Interests incude Aggregates, Base Metals, Industrial Minerals, Precious & Semi-Precious Metals & Stones, Coal & Lignite, Coal Bed Methane, Geothermal & CO2 Sequestration along the Gulf Coast, Commercial Water Rights in East Texas, and Oil & Gas (Louisiana, Pacific NW, and some Eastern US).

Title to Property

Of the approximately 2.3 billion tons of proven and probable coal reserves that we owned or controlled as of December 31, 2010, we owned approximately 99% of the reserves in fee. We lease approximately 20 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.

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. *(Removed and Reserved)*

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 14, 2011, there were approximately 37,800 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, 2009 to December 31, 2010, 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
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
2010					
First Quarter	$27.56	$21.46	$0.5400	05/05/2010	05/14/2010
Second Quarter	$26.01	$18.00	$0.5400	08/05/2010	08/13/2010
Third Quarter	$27.65	$22.85	$0.5400	11/05/2010	11/12/2010
Fourth Quarter	$33.38	$26.25	$0.5400	02/04/2011	02/14/2011

On September 20, 2010, we eliminated all of the incentive distribution rights (IDRs) held by the general partner and affiliates of the general partner. As consideration for the elimination of the IDRs, we issued 32 million common units to the holders of the IDRs. Prior to the transaction, the IDRs received approximately 24% of the quarterly distributions and 48% of any increase in the distribution. Following the transaction, the general partner retained its 2% interest in NRP.

Cash Distributions to Partners

	General Partner	Limited Partners	IDRs	Total Distributions
		(In thousands)		
2008				
Distributions	$3,426	$131,080	$36,801	$171,307
2009				
Distributions	3,762	144,766	39,607	188,135
2010				
Distributions	4,197	174,709	30,943	209,849

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.

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,				
	2010	**2009**	**2008**	**2007**	**2006**
	(In thousands, except per unit and per ton data)				
Income Statement Data:					
Revenues:					
Coal royalties and related revenues	$ 247,218	$ 207,138	$ 238,834	$ 177,088	$150,791
Coal processing and transportation	24,168	20,190	20,437	8,808	1,452
Aggregate royalties	4,230	5,580	9,119	7,434	538
Oil and gas royalties	7,720	7,520	7,902	4,930	4,220
Property taxes	11,270	11,636	9,800	10,285	5,971
Other	6,795	4,020	5,573	6,440	7,701
Total revenues	301,401	256,084	291,665	214,985	170,673
Expenses:					
Depreciation, depletion and amortization	56,978	60,012	64,254	51,391	29,695
General and administrative	29,893	23,102	13,922	20,048	15,520
Property, franchise and other taxes	15,107	14,996	13,558	13,613	8,122
Other	3,362	3,999	2,924	1,634	1,560
Total expenses	105,340	102,109	94,658	86,686	54,897
Income from operations	196,061	153,975	197,007	128,299	115,776
Interest expense, net	(41,600)	(39,895)	(27,001)	(25,800)	(13,686)
Net income	$ 154,461	$ 114,080	$ 170,006	$ 102,499	$102,090
Balance Sheet Data (at period end):					
Land, equipment, coal and other mineral rights, net	$1,530,458	$1,405,083	$1,174,067	$1,222,094	$845,531
Total assets	1,664,036	1,523,590	1,301,340	1,320,031	939,493
Long-term debt	661,070	626,587	478,822	496,057	454,291
Partners' capital	825,180	765,226	743,341	744,591	435,687
Other Data:					
Royalty coal tons produced by lessees	47,052	46,848	60,570	57,232	52,092
Average gross coal royalty revenue per ton	$ 4.71	$ 4.20	$ 3.74	$ 2.99	$ 2.84
Aggregate tons produced by lessees	4,365	3,269	4,791	5,698	412
Average gross aggregate royalty revenue per ton	$ 1.12	$ 1.30	$ 1.31	$ 1.19	$ 1.11
Basic and diluted net income per limited partner unit	$ 1.54	$ 1.17	$ 1.95	$ 1.11	$ 1.60
Weighted average number of units outstanding	81,917	67,702	64,891	64,505	50,682
Distributions per limited partner unit	$ 2.16	$ 2.16	$ 2.07	$ 1.88	$ 1.67

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 mineral properties in the United States. We own coal reserves in the three major U.S. coal-producing regions: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. As of December 31, 2010, we owned or controlled approximately 2.3 billion tons of proven and probable coal reserves, and we also owned approximately 228 million tons of aggregate reserves in a number of states across the country. We do not operate any mines, but 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. 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 generally 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, which vary by lease, 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 25% of our 2010 revenues from other sources, as compared to 21% in 2009. The most significant increase in these other sources of revenue occurred due to a substantial minimum royalty paid by Cline with respect to the Colt reserves that was non-recoupable and therefore recognized as revenue. In addition, we received some oil and gas revenues in 2010 related to our BRP joint venture with International Paper. Other sources of revenue include: coal processing and transportation fees; overriding royalties; wheelage payments; rentals; property tax revenue; and timber.

Elimination of Incentive Distribution Rights

On September 20, 2010, we eliminated all of the incentive distribution rights (IDRs) held by our general partner and affiliates of the general partner. As consideration for the elimination of the IDRs, we issued 32 million common units to the holders of the IDRs. As of the date of this report, there are 106,027,836 common units outstanding and the general partner has retained its 2% interest in the partnership. Prior to the transaction, the IDRs received approximately 24% of the quarterly distribution and 48% of any increase in the distribution. Through the elimination of the IDRs, we believe our limited partner unitholders will benefit from our improved cost of capital through:

- our enhanced competitive position in the acquisition markets; and
- increased returns to limited partner unitholders from acquisition and growth projects.

While the transaction is expected to be dilutive to cash available for distribution in 2011, we believe that the transaction is in the long-term best interest of the partnership.

Our Current Liquidity Position

As of December 31, 2010, we had $206 million in available capacity under our existing credit facility, which matures in March 2012, as well as approximately $95.5 million in cash. Following acquisitions of additional coal and aggregate reserves in the first two months of 2011, we currently have $125 million in available capacity under our credit facility.

Pursuant to the purchase and sale agreement signed in the Colt acquisition, we expect to fund an additional $80 million over the next year as the operator achieves various development milestones. We anticipate funding the Colt acquisition, as well as any other acquisitions that we consummate, 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.

In addition, other than a $35 million senior note that matures in 2013, we amortize our long-term debt. Although our annual principal payments will increase significantly beginning in 2013, we have no need to access the capital markets to pay off or refinance any debt obligations other than the one note, and our existing debt will be reduced as the minerals are depleted.

Current Results

For the year ended December 31, 2010, our lessees produced 51.4 million tons of coal and aggregates, generating $226.0 million in royalty revenues from our properties, and our total revenues were $301.4 million. Prices for both steam and metallurgical coal remained at higher levels than we had forecasted for the second half of 2010, and began to increase further in December 2010 and January 2011 due to the flooding in Australia and increased global demand. Because approximately 38% of our coal royalty revenues and 32% of the related production in 2010 were from metallurgical coal, we expect to continue to benefit as the global economy recovers and the demand for steel remains high.

Even though coal royalty revenues from our Appalachian properties represented 61% of our total revenues in 2010, 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 and other mineral acquisitions. Our expansion into Illinois is through the acquisition of reserves by NRP and the development of greenfield mines by Cline. These projects take several years to reach full production, and it is difficult for us to forecast the timing of completion of the projects. To protect against this risk, we are receiving significant minimum royalties with respect to each of the projects. Although minimums provide cash to NRP that can be distributed to our limited partners, the minimums are generally not revenue to NRP until recouped through production or at the end of the recoupment period. Thus, to the extent that the development takes longer than anticipated to begin production, it will impact the revenues that we receive in the future.

Operations at the Gatling, West Virginia mine were idled in April 2010 and had not been restarted as of the end of the year. Cline, which operates the mine, has communicated to us that it is continuing to maintain the mine and is currently in discussions with AEP regarding modifications to its existing coal sales contract. In prior periods, efforts by Cline to renegotiate the price for coal from this mine were successful. Cline continues to make its quarterly minimum payments with respect to this mine and has also communicated that it will continue to do so for the remainder of the lease term. The net book value of the assets relating to this operation was $133.6 million as of December 31, 2010. As of the date of this report, we have received $19.0 million in minimum royalties, and contractual quarterly minimums for the remainder of the primary term total $69.7 million. Considering all available information, we have completed an undiscounted cash flow analysis of the assets relating to this operation and determined the undiscounted cash flows exceed those assets' carrying values. However, if the mine does not become operational in future periods or discussions with potential purchasers of the coal are not successful, the estimated cash flows may change and we may determine that some of the assets associated with the mine have suffered impairment. This decision and an associated impairment charge could have a material adverse impact on our earnings in the period in which any impairment is recognized, but it would not impact our cash flows from operations or our distributable cash flow.

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.

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. The recent mine disaster at Massey's Upper Big Branch Mine has led to even more scrutiny by MSHA of our lessees' operations, as well as additional mine safety legislation being considered by Congress. 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 existing Clean Air Act is also a possible mechanism for regulating greenhouse gases. In December 2009, the EPA determined that emissions of carbon dioxide, methane, and other greenhouse gases, or "GHGs," present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Legal challenges to these findings have been asserted, and Congress is considering legislation to delay or repeal EPA's actions, but we cannot predict the outcome of these efforts. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act.

In addition, EPA is under a consent decree by which it must propose by July 2011 and take final action by May 2012 on "new source performance standards" to govern GHG emissions from electric generating units, certainly including those fired by coal. The decree also represents EPA's agreement to consider adopting a GHG limitation program governing existing sources, as well, which EPA may attempt to use to establish a cap-and-trade-like system on emissions of power plants' GHG emissions.

Other pending cases regarding GHGs may affect the market for coal. For example, in *AEP v. Connecticut*, the Second Circuit Court of Appeals held that states and private plaintiffs may maintain actions under federal common law alleging that five electric utilities have created a "public nuisance" by contributing to global warming, and may seek injunctive relief capping the utilities' CO_2 emissions at judicially-determined levels. However, the Supreme Court granted certiorari in December 2010 in this case, and argument has not yet been scheduled. An adverse outcome for the defendants in this case or other similar cases could cause additional similar litigation and could adversely affect the demand for our coal.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs, primarily through GHG cap and trade programs. Most proposed cap and trade programs work by requiring major sources of emissions, such as coal-fired electric power plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

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. 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.

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,		
	2010	2009	2008
Net cash provided by operating activities	$258,694	$210,669	$229,956
Less scheduled principal payments	(32,234)	(17,235)	(17,234)
Less reserves for future principal payments	(31,699)	(32,235)	(17,235)
Add reserves used for scheduled principal payments	32,234	17,235	17,234
Distributable cash flow	$226,995	$178,434	$212,721

Recent Acquisitions

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

CALX. In February 2011, we acquired approximately 508 acres of mineral and surface rights related to limestone reserves in Livingston County, Kentucky for a purchase price of $16 million, $11 million of which was funded at closing.

BRP LLC. In June 2010, we and International Paper Company formed BRP to own and manage mineral assets previously owned by International Paper. Some of these assets are currently subject to leases, and certain other assets have not yet been developed but are available for future development by the venture. In exchange for a $42.5 million contribution we became the managing and controlling member with a 51% income interest plus a preferential cumulative annual distribution prior to profit sharing. Identified tangible assets in the transaction include oil and gas, coal and aggregate reserves, as well the rights to other unidentified minerals, which may include coal bed methane, geothermal, CO_2 sequestration, water rights, precious metals, industrial minerals and base metals. Certain properties, including oil and gas, coal and aggregates, as well as land leased for cell towers, are currently under lease and generating revenues.

Rockmart Slate. In June 2010, we acquired approximately 100 acres of mineral and surface rights related to slate reserves in Rockmart, Georgia from a local operator for a purchase price of $6.7 million.

Sierra Silica. In April 2010, we acquired the rights to silica reserves on a 1,000 acre property in Northern California from Sierra Silica Resources LLC for $17.0 million.

North American Limestone. In April 2010, we signed an agreement to build and own a fine grind processing facility for high calcium carbonate limestone located in Putnam County, Indiana. We will lease the facility to a local operator. The total cost for the facility is not to exceed $6.5 million. As of our filing date, we have funded approximately $6.2 million of the acquisition.

Northgate-Thayer. In March 2010, we acquired approximately 100 acres of mineral and surface rights related to dolomite limestone reserves in White County, Indiana from a local operator for a purchase price of $7.5 million.

Massey-Override. In March 2010, we acquired from Massey Energy subsidiaries overriding royalty interests in coal reserves located in southern West Virginia and eastern Kentucky. Total consideration for this purchase was $3.0 million.

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 several separate transactions for a total purchase price of $255 million. As of December 31, 2010, we had acquired approximately 50.2 million tons of reserves associated with the initial production from the mine for approximately $105 million. In January 2011, we closed a transaction for $70.0 million and acquired approximately 41.9 million tons of reserves. As of our filing date, we had acquired approximately 92.1 million tons of reserves associated with the initial production from the mine. 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 $24.0 million.

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 Natural Resource Partners granted Adena Minerals an additional nine percent interest in the general partner.

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.

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, Depletion and Amortization. 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 amortize intangible assets on a units-of-production basis, unless classified as a temporarily idled asset then a minimum amortization is applied. 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.

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 December 2010, the FASB amended how a public entity that enters into a material business combination present comparative financial statements. The amendment specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. This amendment also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. This amendment is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. We adopted this amendment on January 1, 2011 and, therefore, future material acquisitions accounted for as business combinations that are completed by us may be impacted by this amendment.

In December 2010, the FASB modified Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors that would indicate an impairment may exist. The qualitative factors are consistent with the existing guidance, which requires that goodwill of a reporting unit be tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. This amendment is effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2010. We do not expect this adoption to have a material impact on the financial statements. However, if future business combinations result in goodwill this guidance may become relevant.

In February 2010, the FASB amended the subsequent events standard, removing the requirement for an SEC filer to disclose the date it issued and revised financial statements. The FASB added that revised financial statements include financial statements revised as a result of either correction of an error or retrospective application of U.S. GAAP. We adopted this amendment for the quarter ended March 31, 2010. The adoption did not have a material impact on our disclosures.

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 8. "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, 2009 and interim periods within those fiscal years. We applied the effective provisions of this amendment in preparing our disclosures; however, the adoption of the standard did not have a material effect on such disclosures.

On January 1, 2009, we adopted new standards for the accounting and reporting of non-controlling interests in a subsidiary. As discussed in Note 3, in connection with the business combination completed in June 2010, we acquired a controlling interest in a newly formed venture. All assets and liabilities of the venture are included in the consolidated balance sheet and the non-controlling interest in the venture is reflected as a component of equity; the revenues and expenses of the venture are reflected in consolidated results of operations with separate disclosure of the earnings or losses allocable to the non-controlling interest.

Other accounting standards that have been issued or proposed by the FASB or other standards-setting bodies are not expected to have a material impact on our financial position, results of operations and cash flows.

Results of Operations

Summary of 2010 and 2009 Royalties and Production

	For the Years Ended December 31, 2010	2009	Increase (Decrease)	Percentage Change
	(In thousands, except percent and per ton data)			
Coal royalties				
Appalachia				
Northern	$ 18,676	$ 14,959	$ 3,717	25%
Central	144,934	132,543	12,391	9%
Southern	19,405	19,382	23	<1%
Total Appalachia	183,015	166,884	16,131	10%
Illinois Basin	30,210	22,019	8,191	37%
Northern Powder River Basin	8,444	7,718	726	9%
Gulf Coast	92	—	92	100%
Total	$221,761	$196,621	$25,140	13%
Production (tons)				
Appalachia				
Northern	4,900	4,943	(43)	(1)%
Central	27,056	28,032	(976)	(3)%
Southern	2,824	3,233	(409)	(13)%
Total Appalachia	34,780	36,208	(1,428)	(4)%
Illinois Basin	7,753	6,656	1,097	16%
Northern Powder River Basin	4,467	3,984	483	12%
Gulf Coast	52	—	52	100%
Total	47,052	46,848	204	<1%
Average gross royalty revenue per ton				
Appalachia				
Northern	$ 3.81	$ 3.03	$ 0.78	26%
Central	5.36	4.73	0.63	13%
Southern	6.87	6.00	0.87	15%
Total Appalachia	5.26	4.61	0.65	14%
Illinois Basin	3.90	3.31	0.59	18%
Northern Powder River Basin	1.89	1.94	(0.05)	(3)%
Gulf Coast	1.77	—	1.77	100%
Combined average gross royalty revenue per ton	$ 4.71	$ 4.20	$ 0.51	12%
Aggregates				
Royalty revenues	$ 4,869	$ 4,260	$ 609	14%
Aggregate Bonus Royalty	$ (639)	$ 1,320	$ (1,959)	(148)%
Production	4,365	3,269	1,096	34%
Average gross royalty revenue per ton	$ 1.12	$ 1.30	$ (0.18)	(14)%

Coal Royalty Revenues and Production

Coal royalty revenues comprised approximately 74% and 77% of our total revenue for the years ended December 31, 2010 and 2009, respectively. The following is a discussion of the coal royalty revenues and production derived from our major coal producing regions:

Appalachia. Primarily as a result of higher prices being received by our lessees, and the improved royalty rates negotiated on one of our leases, coal royalty revenues increased by $16.1 million in 2010. The 1.4 million ton decline in production 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, the temporary idling of two mines and some mines moving their production onto adjacent property.

Illinois Basin. Coal royalty revenues and production on our properties were both higher in 2010. Coal royalty revenues increased by $8.2 million and production increased by 1.1 million tons. The increased production was due to the mine on our Macoupin property operating for the entire year and some of the other mines having increased production. In general, our lessees received higher prices for their production, increasing our royalty per ton.

Northern Powder River Basin. The increase in both coal royalty revenues of $0.7 million and production of 483,000 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 in a number of states across the country. For the year ended December 31, 2010, we recognized $4.2 million in royalty revenue from aggregates, which included a reversal of a bonus payment accrual of $0.6 million, under the terms of one of our leases. For the same period for 2009, we recognized royalty revenue from aggregates of $5.6 million, which included bonus revenue of $1.3 million under the same lease. We had production of 4.4 million tons and 3.3 million tons for each of these years.

Summary of 2009 and 2008 Royalties and Production

	For the Years Ended December 31, 2009	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	$ 0.09	3%
Central	4.73	4.34	0.39	9%
Southern	6.00	4.64	1.36	29%
Total Appalachia	4.61	4.19	0.42	10%
Illinois Basin	3.31	2.61	0.70	27%
Northern Powder River Basin	1.94	1.85	0.09	5%
Combined average gross royalty revenue per ton	$ 4.20	$ 3.74	$ 0.46	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	$ (0.01)	(1)%

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 we generated more coal royalty revenues from lower production. 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 recognized a bonus royalty payment of $1.3 million from the Washington reserves compared to $2.8 million in 2008. The reduction in tonnage and royalty is primarily attributed to lower demand caused by the poorer economic conditions in 2009.

Other Operating Results

Coal Processing and Transportation Revenues. We generated $9.6 million, $7.7 million and $8.8 million in processing revenues for the years ended December 31, 2010, 2009 and 2008. 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. The increase in processing revenues for the year ended December 31, 2010 is primarily due to higher volumes at higher prices. The increase in 2010 also reflects the addition of the preparation plant at Macoupin being online for a full year. The decrease in 2009 reflects the lower demand due to the depressed economy.

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 $14.6 million, $12.5 million and $11.7 million for the years ended December 31, 2010, 2009 and 2008, 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. Our Macoupin property coming online late in 2009 and operating a full year in 2010 also contributed to the increase late in 2009 and in 2010.

Additional Revenues. In addition to coal royalties, aggregate royalties, coal processing and transportation revenues, we generated approximately 17%, 13% and 12% of our revenues from other sources for the years ended December 31, 2010, 2009 and 2008, respectively. These other sources include: oil and gas royalties, property taxes, minimums recognized, overriding royalties, timber, rentals and wheelage. Minimums recognized as revenues increased in 2010 by $12.9 million primarily due to a non-recoupable minimum on our Colt reserves received in 2010. In future years, the minimums received with respect to this property will be reflected as revenue only when recouped through production.

Operating costs and expenses. Included in total expenses are:

- Depreciation, depletion and amortization of $57.0 million, $60.0 million and $64.3 million for the years ended December 31, 2010, 2009 and 2008, respectively. Excluding a onetime expense of $8.2 million for a terminated lease due to a mine closure, depletion increased from 2009 due to a refinement of our accounting policy for contract amortization during 2010. Depletion decreased in 2009 from 2008 as a result of lower total production for 2009.

- General and administrative expenses of $29.9 million, $23.1 million and $13.9 million for the years ended December 31, 2010, 2009 and 2008, 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 and additional personnel required to manage our properties. The increase from 2010 over 2009 also reflects expenses of $2.5 million associated with the formation of the venture with International Paper Company during 2010.
- Property, franchise and other taxes were $15.1 million, $15.0 million and $13.6 million for the years ended December 31, 2010, 2009 and 2008, respectively. The increase in 2010 and 2009 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 statements of income.

Interest Expense. Interest expense was $41.6 million, $40.1 million and $28.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. Due to additional debt incurred to fund acquisitions as well as higher interest rates on the senior notes issued in 2009, interest expense has increased since 2008.

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 matures in March 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 senior notes 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 2010, 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 acquisitions of coal and aggregate reserves in the first two months of 2011, we had $125 million in available capacity under our credit facility. We also had approximately $95.5 million of cash available at the end of the year.

Net cash provided by operations for the years ended December 31, 2010, 2009 and 2008 was $258.7, $210.7 million and $230.0 million, respectively. The most 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, 2010, 2009 and 2008 was $170.8, $119.9 million and $9.8 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.

Net cash used for financing activities for the years ended December 31, 2010, 2009 and 2008 was $75.0 million, $98.1 million and $188.5 million, respectively. We had proceeds from loans of $140.0 million and $331.0 million for the years ended December 31, 2010 and 2009. We did not receive any proceeds from loans for the year ended December 31, 2008. We had proceeds from the issuance of units of $110.4 million for the year ended December 31, 2010. We did not receive any proceeds from the issuance of units for the years ended December 31, 2009 and 2008. The proceeds were offset by repayments of credit facility borrowings of $74.0 million and $151.0 million for the years ended December 31, 2010 and 2009, respectively. We also made $32.2 million, $17.2 million and $17.2 million in principal payments on our senior notes for the years ended December 31, 2010, 2009 and 2008, respectively. The proceeds were also offset by retirement of purchase obligations related to the purchase of reserves and infrastructure of $9.2 million and $72.0 million for the years ended December 31, 2010 and 2009, respectively. We paid distributions of $209.8 million, $188.1 million and $171.3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Contractual Obligations and Commercial Commitments

Credit Facility. We have a $300 million revolving credit facility, and as of the date of this report we had approximately $125 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, 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 elect to bring new lenders into the facility, but cannot make any assurance that the additional credit capacity will be available to us on existing or comparable terms.

During 2010, our borrowings and repayments under our credit facility were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Outstanding balance, beginning of period	$28,000	$ 74,000	$35,000	$39,000
Borrowings under credit facility	46,000	35,000	4,000	55,000
Less: Repayments under credit facility	—	(74,000)	—	—
Outstanding balance, ending period	$74,000	$ 35,000	$39,000	$94,000

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 listed below under a note purchase agreement as supplemented from time to time. 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.

Long-Term Debt

At December 31, 2010, our debt consisted of:

- $94.0 million of our $300 million floating rate revolving credit facility, due March 2012;
- $35.0 million of 5.55% senior notes due 2013;
- $37.7 million of 4.91% senior notes due 2018;
- $150.0 million of 8.38% senior notes due 2019;
- $76.9 million of 5.05% senior notes due 2020;
- $2.1 million of 5.31% utility local improvement obligation due 2021;
- $36.9 million of 5.55% senior notes due 2023;
- $210.0 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 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.

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2010 (in millions):

	Payments Due by Period						
Contractual Obligations	**Total**	**2011**	**2012**	**2013**	**2014**	**2015**	**Thereafter**
Long-term debt principal payments (including current maturities)(1)	$ 692.6	$ 31.5	$124.8	$ 87.2	$56.2	$56.2	$ 336.7
Long-term debt interest payments(2)	239.5	38.4	36.7	33.2	28.5	24.7	78.0
Pending acquisitions(3)	150.0	110.0	40.0	—	—	—	—
Rental leases(4)	4.3	0.6	0.6	0.5	0.5	0.5	1.6
Total	$1,086.4	$180.5	$202.1	$120.9	$85.2	$81.4	$416.30

(1) The amounts indicated in the table include principal due on our senior notes, as well as the utility local improvement obligation related to our property in DuPont, Washington. The table also includes the $94.0 million outstanding principal balance under our credit facility, which matures in March 2012.

(2) The amounts indicated in the table include interest due on our senior notes as well as the utility local improvement obligation related to our property in DuPont, Washington.

(3) The amounts indicated in the table include $150.0 million related to the future anticipated acquisitions with Colt LLC. Future acquisitions from Colt LLC are based upon certain milestones relating to the new mines construction. Upon each closing we receive title to additional reserves. In January 2011 we funded another Colt LLC acquisition for approximately $70.0 million.

(4) 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 Securities and Exchange Commission 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.

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, 2010, 2009 and 2008.

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, 2010. 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 the 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.

The reimbursements to our general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation are as follows:

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands)		
Reimbursement for services	$7,358	$6,822	$5,557

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 our general partner, as well as 21,017,441 common units. At December 31, 2010, we had accounts receivable totaling $6.5 million from Cline affiliates. Revenues from the Cline affiliates are as follows:

	For the Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Coal royalty revenues	$32,407	$23,325	$19,255
Coal processing fees	1,337	193	—
Transportation fees	14,324	11,495	6,895
Minimums recognized as revenue	12,400	—	—
Override revenue	1,904	2,356	1,788
	$62,372	$37,369	$27,938

As of December 31, 2010, we had received $47.0 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $22.8 million was received in the current year.

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, the Partnership 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. NRP currently has 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. NRP owns and leases the plants to

Taggart Global, which designs, builds and operates 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. Revenues from Taggart are as follows:

	For the Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Coal processing revenue	$5,874	$3,872	$4,971

At December 31, 2010, we had accounts receivable totaling $1.3 million from Taggart.

A fund controlled by Quintana Capital owns Kopper-Glo, a small coal mining company that is one of the Partnership's lessees with operations in Tennessee. Revenues from Kopper-Glo are as follows:

	For the Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Coal royalty revenues	$1,545	$1,560	$1,445

NRP also had accounts receivable totaling $0.1 million from Kopper-Glo at December 31, 2010.

Office Building in Huntington, West Virginia

On January 1, 2009, we began leasing substantially all of two floors of an office building in Huntington, West Virginia 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, 2010, we had $94 million outstanding in variable interest debt. If interest rates were to increase by 1%, annual interest expense would increase $940,000, assuming the same principal amount remained outstanding during the year.

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

INDEX TO FINANCIAL STATEMENTS

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, 2010 and 2009, and the related consolidated statements of income, partners' capital, and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

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, 2010, 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 28, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Houston, Texas
February 28, 2011

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED BALANCE SHEETS

	December 31, 2010	December 31, 2009
	(In thousands, except for unit information)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 95,506	$ 82,634
Accounts receivable, net of allowance for doubtful accounts	26,195	27,141
Accounts receivable — affiliates	7,915	4,342
Other	910	930
Total current assets	130,526	115,047
Land	24,543	24,343
Plant and equipment, net	62,348	64,351
Coal and other mineral rights, net	1,281,636	1,151,835
Intangible assets, net	161,931	164,554
Loan financing costs, net	2,436	2,891
Other assets, net	616	569
Total assets	$1,664,036	$1,523,590
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,388	$ 914
Accounts payable — affiliates	499	179
Obligation related to acquisition	—	2,969
Current portion of long-term debt	31,518	32,235
Accrued incentive plan expenses — current portion	6,788	4,627
Property, franchise and other taxes payable	6,926	6,164
Accrued interest	9,811	10,300
Total current liabilities	56,930	57,388
Deferred revenue	109,509	67,018
Accrued incentive plan expenses	11,347	7,371
Long-term debt	661,070	626,587
Partners' capital:		
Common units outstanding: (106,027,836 in 2010, 69,451,136 in 2009)	806,529	747,437
General partner's interest	14,132	13,409
Holders of incentive distribution rights	—	4,977
Non-controlling interest	5,065	—
Accumulated other comprehensive loss	(546)	(597)
Total partners' capital	825,180	765,226
Total liabilities and partners' capital	$1,664,036	$1,523,590

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF INCOME

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands, except per unit data)		
Revenues:			
Coal royalties	$221,761	$196,621	$226,250
Aggregate royalties	4,230	5,580	9,119
Coal processing fees	9,604	7,673	8,781
Transportation fees	14,564	12,517	11,656
Oil and gas royalties	7,720	7,520	7,902
Property taxes	11,270	11,636	9,800
Minimums recognized as revenue	14,199	1,266	1,257
Override royalties	11,258	9,251	11,327
Other	6,795	4,020	5,573
Total revenues	301,401	256,084	291,665
Operating costs and expenses:			
Depreciation, depletion and amortization	56,978	60,012	64,254
General and administrative	29,893	23,102	13,922
Property, franchise and other taxes	15,107	14,996	13,558
Transportation costs	1,864	1,611	1,416
Coal royalty and override payments	1,498	2,388	1,508
Total operating costs and expenses	105,340	102,109	94,658
Income from operations	196,061	153,975	197,007
Other income (expense)			
Interest expense	(41,635)	(40,108)	(28,356)
Interest income	35	213	1,355
Income before non-controlling interest	154,461	114,080	170,006
Non-controlling interest	—	—	—
Net income	$154,461	$114,080	$170,006
Net income attributable to:			
General partner	$ 2,570	$ 1,611	$ 2,602
Holders of incentive distribution rights	$ 25,966	$ 33,515	$ 39,914
Limited partners	$125,925	$ 78,954	$127,490
Basic and diluted net income per limited partner unit	$ 1.54	$ 1.17	$ 1.95
Weighted average number of units outstanding	81,917	67,702	64,891

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

NATURAL RESOURCE PARTNERS L.P.

STATEMENT OF PARTNERS' CAPITAL

	Common Units		General Partner	Holders of Incentive Distribution Rights	Non-Controlling Interest	Accumulated Other Comprehensive	
	Units	Amounts	Amounts	Amounts	Amounts	Income (Loss)	Total
	(In thousands, except unit data)						
Balance at December 31, 2007	64,891,136	$ 722,931	$14,405	$ 7,954	$ —	$(699)	$ 744,591
Distributions to unitholders	—	(131,080)	(3,428)	(36,799)	—	—	(171,307)
Net income for the year ended December 31, 2008	—	127,490	2,602	39,914	—	—	170,006
Loss on interest hedge	—	—	—	—	—	51	51
Comprehensive income	—	—	—	—	—	51	170,057
Balance at December 31, 2008	64,891,136	$ 719,341	$13,579	$ 11,069	$ —	$(648)	$ 743,341
Distributions to unitholders	—	(144,766)	(3,762)	(39,607)	—	—	(188,135)
Issuance of units for acquisitions, net	4,560,000	93,908	1,981	—	—	—	95,889
Net income for the year ended December 31, 2009	—	78,954	1,611	33,515	—	—	114,080
Loss on interest hedge	—	—	—	—	—	51	51
Comprehensive income	—	—	—	—	—	51	114,131
Balance at December 31, 2009	69,451,136	$ 747,437	$13,409	$ 4,977	$ —	$(597)	$ 765,226
Distributions to unitholders	—	(174,709)	(4,197)	(30,943)	—	—	(209,849)
Issuance of units, net	36,576,700	110,217	—	—	—	—	110,217
Capital contribution	—	—	2,350	—	—	—	2,350
Fees associated with elimination of IDRs	—	(2,341)	—	—	—	—	(2,341)
Non-controlling interest	—	—	—	—	5,065	—	5,065
Net income for the year ended December 31, 2010	—	125,925	2,570	25,966	—	—	154,461
Loss on interest hedge	—	—	—	—	—	51	51
Comprehensive income	—	—	—	—	—	51	154,512
Balance at December 31, 2010	106,027,836	$ 806,529	$14,132	$ —	$5,065	$(546)	$ 825,180

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

NATURAL RESOURCE PARTNERS L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash flows from operating activities:			
Net income	$ 154,461	$ 114,080	$ 170,006
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	56,978	60,012	64,254
Non-cash interest charge	540	1,463	278
Gain(loss) on sale of assets	—	—	33
Change in operating assets and liabilities:			
Accounts receivable	(2,627)	581	(4,586)
Other assets	(27)	(67)	178
Accounts payable and accrued liabilities	468	(133)	(1,484)
Accrued interest	(489)	3,850	143
Deferred revenue	42,491	26,264	4,468
Accrued incentive plan expenses	6,137	4,577	(3,041)
Property, franchise and other taxes payable	762	42	(293)
Net cash provided by operating activities	258,694	210,669	229,956
Cash flows from investing activities:			
Acquisition of land, coal, other mineral rights and related intangibles	(166,382)	(118,754)	(5,500)
Acquisition or construction of plant and equipment	(5,994)	(1,157)	(10,568)
Proceeds from sale of assets	1,580	—	—
Change in restricted accounts	—	—	6,240
Net cash used in investing activities	(170,796)	(119,911)	(9,828)
Cash flows from financing activities:			
Proceeds from loans	140,000	331,000	—
Proceeds from issuance of units	110,436	—	—
Deferred financing costs	—	(661)	—
Repayments of loans	(106,234)	(168,235)	(17,234)
Retirement of purchase obligation related to reserves and infrastructure	(9,169)	(72,000)	—
Costs associated with unit issuance	(219)	(21)	—
Fees associated with elimination of IDRs	(2,341)	—	—
Distributions to partners	(209,849)	(188,135)	(171,307)
Contributions by general partner	2,350	—	—
Net cash used in financing activities	(75,026)	(98,052)	(188,541)
Net increase (decrease) in cash and cash equivalents	12,872	(7,294)	31,587
Cash and cash equivalents at beginning of period	82,634	89,928	58,341
Cash and cash equivalents at end of period	$ 95,506	$ 82,634	$ 89,928
Supplemental cash flow information:			
Cash paid during the period for interest	$ 41,565	$ 34,710	$ 27,735
Non-cash investing activities:			
Equity issued for acquisitions	$ —	$ 95,910	$ —
Assets contributed by general partner for acquisitions	—	1,981	—
Liability assumed from acquisitions	1,593	1,170	—
Non-controlling interest	(5,065)	—	—
Non-cash financing activities:			
Purchase obligation related to reserve and infrastructure acquisitions	6,200	74,022	—

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

1. Basis of Presentation and Organization

Natural Resource Partners L.P. (the "Partnership"), a Delaware limited partnership, was formed in April 2002. The general partner of the Partnership is NRP (GP) LP, a Delaware limited partnership, whose general partner is GP Natural Resource Partners LLC, a Delaware limited liability company. The Partnership engages principally in the business of owning and managing mineral properties in the United States. The Partnership owns coal reserves in the three major coal-producing regions of the United States: Appalachia, the Illinois Basin and the Western United States, as well as lignite reserves in the Gulf Coast region. As of December 31, 2010, the Partnership owned or controlled approximately 2.3 billion tons of proven and probable coal reserves (unaudited), and also owned approximately 228 million tons of aggregate reserves (unaudited) in a number of states across the country. The Partnership does not operate any mines, but leases reserves to experienced mine operators under long-term leases that grant the operators the right to mine reserves in exchange for royalty payments. Lessees are generally required to make royalty payments based on the higher of a percentage of the gross sales price or a fixed price per ton, in addition to a minimum payment.

In addition, the Partnership owns coal transportation and preparation equipment, aggregate reserves, other coal related rights and oil and gas properties on which it earns revenue.

The Partnership's operations are conducted through, and its operating assets are owned by, its subsidiaries. The Partnership owns its subsidiaries through a wholly owned operating company, NRP (Operating) LLC. NRP (GP) LP, the general partner of the Partnership, has sole responsibility for conducting its business and for managing its operations. Because its 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 its 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. Mr. Robertson is entitled to nominate all nine of the directors, five of whom must be independent directors, to the board of directors of GP Natural Resource Partners LLC. In connection with the Cline acquisition, Mr. Robertson delegated the right to nominate two of the directors, one of whom must be independent, to Adena Minerals, LLC, an affiliate of the Cline Group.

2. Summary of Significant Accounting Policies

Principles of Consolidation

The financial statements include the accounts of Natural Resource Partners L.P. and its wholly owned subsidiaries as well as BRP LLC, a venture with International Paper Company controlled by the Partnership. Intercompany transactions and balances have been eliminated.

Reclassification

Certain reclassifications have been made to the prior year's financial statements. Immaterial amounts relating to the AzConAgg and Gatling Ohio acquisitions have been reclassified between various assets based upon more information received by the Partnership with respect to those assets.

Business Combinations

For purchase acquisitions accounted for as a business combination, the Partnership is required to record the assets acquired, including identified intangible assets and liabilities assumed at their fair value, which in many instances involves estimates based on third party valuations, such as appraisals, or internal valuations based on discounted cash flow analyses or other valuation techniques. For additional discussion concerning the Partnership's valuation of intangible assets, see Note 7, "Intangible Assets."

Fair Value Measurements

The Partnership accounts for fair value measurements, including disclosures, using Financial Accounting Standard Board's (FASB) fair value standard. For additional discussion concerning the Partnership's fair value measurement, see Note 9, "Fair Value Measurements".

Use of Estimates

Preparation of the accompanying financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash Equivalents and Restricted Cash

The Partnership considers all highly liquid short-term investments with an original maturity of three months or less to be cash equivalents. Restricted cash includes deposits to secure performance under contracts acquired as part of the Cline acquisition. Earnings on the restricted cash are available to the Partnership. Performance under the Cline contracts was completed in November 2008 and the funds were released from escrow at that time.

Accounts Receivable

Accounts receivable are recorded by the Partnership's lessees in the ordinary course of business, and do not bear interest. Receivables are recorded net of the allowance for doubtful accounts in the accompanying consolidated balance sheets. The Partnership evaluates the collectability of its accounts receivable based on a combination of factors. The Partnership regularly analyzes its lessees' accounts and when it becomes aware of a specific customer's inability to meet its financial obligations to the Partnership, such as in the case of bankruptcy filings or deterioration in the lessee's operating results or financial position, the Partnership records a specific reserve for bad debt to reduce the related receivable to the amount it reasonably believes is collectible. Accounts are charged off when collection efforts are complete and future recovery is doubtful. If circumstances related to specific lessees change, the Partnership's estimates of the recoverability of receivables could be further adjusted.

Land, Coal and Mineral Rights

Land, coal and other mineral rights owned and leased are recorded at cost. Coal and other mineral rights are depleted on a unit-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 therein, or over the amortization period of the contractual rights.

Plant and Equipment

Plant and equipment consists of coal preparation plants, related coal handling facilities, and other coal and aggregate processing and transportation infrastructure. Expenditures for new facilities and expenditures that substantially increase the useful life of property, including interest during construction, are capitalized and reported in the Consolidated Statements of Cash Flows. These assets are recorded at cost and are being depreciated on a straight-line basis over their useful lives, which range from three to twenty years.

Intangible Assets

The Partnership's intangible assets consist of above-market contracts. Intangible assets are identified related to contracts acquired when compared to the estimate of current market rates for similar contracts. The estimated fair value of the above-market rate contracts are determined based on the present value of future cash flow projections related to the underlying assets acquired. Intangible assets are amortized on a unit-of-production basis. In April 2010, the Partnership was notified by a lessee that its production would be temporarily idled but that the lessee would continue its development work in other areas of the mine. As a result of these circumstances, the Partnership refined its accounting policy to reflect a minimum amortization to be applied in each period for temporarily idled assets. For the year ended December 31, 2010, the Partnership recorded amortization expense of $4.8 million, or approximately $0.06 per unit, that relates to the minimum amortization.

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. During 2009, included in depletion is a charge of $8.2 million related to a terminated lease from a mine closure.

Concentration of Credit Risk

Substantially all of the Partnership's accounts receivable result from amounts due from third-party companies in the coal industry, with approximately 61% of our total revenues being attributable to coal royalty revenues from Appalachia. This concentration of customers may impact the Partnership's overall credit risk, either positively or negatively, in that these entities may be affected by changes in economic or other conditions. Receivables are generally not collateralized.

Deferred Financing Costs

Deferred financing costs consist of legal and other costs related to the issuance of the Partnership's revolving credit facility and senior notes. These costs are amortized over the term of the debt.

Revenues

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

Coal Processing and Transportation Fees. Coal processing fees are recognized on the basis of tons of coal processed through the facilities by the Partnership's lessees and the corresponding revenue from those sales. Generally, the lessees of the coal processing facilities make payments to the Partnership 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, the Partnership receives 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 the Partnership's 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.

Property Taxes

The Partnership is responsible for paying property taxes on the properties it owns. Typically, the lessees are contractually responsible for reimbursing the Partnership for property taxes on the leased properties. The reimbursement of property taxes is included in revenues in the statements of income as property taxes.

Income Taxes

No provision for income taxes related to the operations of the Partnership has been included in the accompanying financial statements because, as a partnership, it is not subject to federal or material state income taxes and the tax effect of its activities accrues to the unitholders. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under its partnership agreement. In the event of an examination of the Partnership's tax return, the tax liability of the partners could be changed if an adjustment in the Partnership's income is ultimately sustained by the taxing authorities.

Share-Based Payment

The Partnership accounts for awards under its Long-Term Incentive Plan under FASB's stock compensation authoritative guidance. This authoritative guidance provides that grants must be accounted for using the fair value method, which requires the Partnership 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.

New Accounting Standards

In December 2010, the FASB amended how a public entity that enters into a material business combination present comparative financial statements. The amendment specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. This amendment also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. This amendment is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The Partnership will adopt this amendment on January 1, 2011 and, therefore, disclosures related to future material acquisitions accounted for as business combinations that are completed by the Partnership may be impacted by this amendment.

In December 2010, the FASB modified Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors that would indicate an impairment may exist. The qualitative factors are consistent with the existing guidance, which requires that goodwill of a reporting unit be tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. This amendment is effective for fiscal years, and interim periods within those years, beginning on or after December 15, 2010. The Partnership does not expect this adoption to have a material impact on the financial statements. However, if future business combinations result in goodwill this guidance may become relevant.

In February 2010, the FASB amended the subsequent events standard, removing the requirement for an SEC filer to disclose the date it issued and revised financial statements. The FASB added that revised financial statements include financial statements revised as a result of either correction of an error or retrospective application of U.S. GAAP. The Partnership adopted this amendment for the quarter ended March 31, 2010. The adoption did not have a material impact on the Partnership's disclosures.

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, 2009 and interim periods within those fiscal years. The Partnership applied the effective provisions of this amendment in preparing its disclosures; however, the adoption of the standard did not have a material effect on such disclosures.

On January 1, 2009, the Partnership adopted new standards for the accounting and reporting of non-controlling interests in a subsidiary. As discussed in Note 3, in connection with the business combination completed in June 2010, the Partnership acquired a controlling interest in a newly formed venture. All assets and liabilities of the venture are included in the consolidated balance sheet and the non-controlling interest in the venture is reflected as a component of equity; the revenues and expenses of the venture are reflected in consolidated results of operations with separate disclosure of the earnings or losses allocable to the non-controlling interest.

Other accounting standards that have been issued or proposed by the FASB or other standards-setting bodies are not expected to have a material impact on the Partnership's financial position, results of operations and cash flows.

3. Acquisitions

BRP LLC. In June 2010, the Partnership and International Paper Company ("IPC") formed BRP to own and manage mineral assets previously owned by IPC. Some of these assets are currently subject to leases, and certain other assets are available for future development by the venture. In exchange for a $42.5 million contribution, NRP became the controlling member with the right to designate two of the three managers of BRP. NRP has a 51% income interest plus a preferential cumulative annual distribution prior to profit sharing. In exchange for the contribution of the producing properties and the properties not currently producing, IPC received $42.5 million in cash, a minority voting interest and a 49% income interest after the preferential cumulative annual distribution. The amount of the preference is fixed throughout the life of the venture but can be reduced by a portion of the proceeds received from sales of producing properties included in the initial acquisition. Identified tangible assets included in the transaction are oil and gas, coal, and aggregate reserves, as well the rights to other unidentified minerals which may include coal bed methane, geothermal, CO_2 sequestration, water rights, precious metals, industrial minerals and base metals. Certain properties, including oil and gas, coal and aggregates, as well as land leased for cell towers, are currently under lease and generating revenues.

The transaction was accounted for as a business combination and, at December 31, 2010, the assets and liabilities of the venture are included in the consolidated balance sheet. The allocation of the purchase price was based on preliminary results of independent third party valuations. The initial estimates and assumptions used are subject to change upon the receipt of additional information required to finalize the valuations, which may result in changes to the coal and other mineral rights, intangible assets and non-controlling interests. The final valuation of the assets is expected to be completed as soon as possible, but no later than one year from the acquisition date. The following table summarizes the preliminary estimated fair values of the assets acquired and liabilities assumed for the BRP transaction (in thousands):

Coal and other mineral rights	$45,759
Intangible assets	1,806
Capital contribution	42,500
Non-controlling interests	5,065

Approximately $38.3 million of the total $47.6 million asset fair value, as well as the value of the $5.1 million non-controlling interest, were estimated using an expected cash flows approach. The remaining assets fair value was determined using a market approach. The capital contribution was funded through a $30 million draw on the Partnership's credit facility and the remainder was funded with available cash. See Note 9, "Fair Value Measurements". The identification of all tangible and intangible assets acquired as well as the valuation process required for the allocation of the purchase price to those assets is not complete.

Operations of the venture are included from June 1, 2010, the effective date of acquisition. Total net income from startup through December 31, 2010 was $2.3 million. The venture operating agreement provides that net income of the venture only be allocated to the non-controlling interests after the preferential cumulative annual distribution. As earnings for the period ended December 31, 2010 were less than the preference amount, no earnings were allocated to the non-controlling interest.

Transaction expenses related to the acquisition were $2.5 million and are included in general and administrative expenses in the accompanying Consolidated Statements of Income.

Rockmart Slate. In June 2010, the Partnership acquired approximately 100 acres of mineral and surface rights related to slate reserves in Rockmart, Georgia from a local operator for a purchase price of $6.7 million.

Sierra Silica. In April 2010, the Partnership acquired the rights to silica reserves on approximately 1,000 acres of property in Northern California for $17.0 million.

North American Limestone. In April 2010, the Partnership signed an agreement to build and own a fine grind processing facility for high calcium carbonate limestone located in Putnam County, Indiana. The Partnership will lease the facility to a local operator. The total cost for the facility is not to exceed $6.5 million. As of December 31, 2010 the Partnership had incurred approximately $5.9 million of costs associated with the construction of the facility.

Northgate-Thayer. In March 2010, the Partnership acquired approximately 100 acres of mineral and surface rights related to dolomite limestone reserves in White County, Indiana from a local operator for a purchase price of $7.5 million.

Massey-Override. In March 2010, the Partnership acquired from Massey Energy subsidiaries overriding royalty interests in coal reserves located in southern West Virginia and eastern Kentucky. Total consideration for this purchase was $3.0 million.

AzConAgg. In December 2009, the Partnership 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, the Partnership 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 several separate transactions for a total purchase price of $255 million. As of December 31, 2010, the Partnership had acquired approximately 50.2 million tons of reserves associated with the initial production from the mine for approximately $105 million. Future closings anticipated through 2012 will be associated with completion of certain milestones related to the new mine.

Blue Star. In July 2009, the Partnership acquired approximately 121 acres of limestone reserves in Wise County, Texas from Blue Star Materials, LLC for a purchase price of $24 million.

Gatling Ohio. In May 2009, the Partnership 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. The Partnership issued 4,560,000 common units to Adena Minerals in connection with this acquisition. In addition, the general partner of Natural Resource Partners granted Adena Minerals an additional nine percent interest in the general partner.

Massey-Jewell Smokeless. In March 2009, the Partnership 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 the Partnership previously held a one-fifth interest. Total consideration for this purchase was $12.5 million.

Macoupin. In January 2009, the Partnership 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.

4. Allowance for Doubtful Accounts

Activity in the allowance for doubtful accounts for the years ended December 31, 2010, 2009 and 2008 was as follows:

	2010	2009	2008
		(In thousands)	
Balance, January 1	$372	$366	$ 1,272
Provision charged to operations:			
Additions to the reserve	309	37	366
Collections of previously reserved accounts	—	(31)	(1,037)
Total charged (credited) to operations	309	6	(671)
Non-recoverable balances written off	—	—	(235)
Balance, December 31	$681	$372	$ 366

5. Plant and Equipment

The Partnership's plant and equipment consist of the following:

	December 31, 2010	December 31, 2009
	(In thousands)	
Plant construction in process	$ 6,279	$ —
Plant and equipment at cost	81,906	81,866
Less accumulated depreciation	(25,837)	(17,515)
Net book value	$ 62,348	$ 64,351

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands)		
Total depreciation expense on plant and equipment	$8,322	$7,998	$4,965

6. Coal and Other Mineral Rights

The Partnership's coal and other mineral rights consist of the following:

	December 31, 2010	December 31, 2009
	(In thousands)	
Coal and other mineral rights	$1,629,286	$1,460,984
Less accumulated depletion and amortization	(347,650)	(309,149)
Net book value	$1,281,636	$1,151,835

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands)		
Total depletion and amortization expense on coal and other mineral interests	$38,501	$48,591	$55,896

Included in depletion in 2009 is a charge of $8.2 million related to a terminated lease from a mine closure.

7. Intangible Assets

In 2010, the Partnership identified $7.5 million of contract intangibles relating to the Sierra Silica acquisition and the IPC venture. In 2009, the Partnership identified $65.8 million of contract intangibles relating to the Gatling Ohio and Macoupin acquisitions. Amounts recorded as intangible assets along with the balances and accumulated amortization at December 31, 2010 and 2009 are reflected in the table below:

	December 31, 2010	December 31, 2009
	(In thousands)	
Contract intangibles	$180,233	$172,706
Less accumulated amortization	(18,302)	(8,152)
Net book value	$161,931	$164,554

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands)		
Total amortization expense on intangible assets	$10,150	$3,423	$3,394

Intangible assets are amortized on a unit-of-production basis. In April 2010, the Partnership was notified by a lessee that its production would be temporarily idled. The lessee has communicated to the Partnership that it does not intend to close the mine, is continuing to maintain the mine and is currently in discussions regarding modifications to its existing coal sales contract, as well as other potential purchases of the coal. As a result of these circumstances, the Partnership refined its accounting policy to reflect a minimum amortization to be applied in each period for temporarily idled assets. For the year ended December 31, 2010, the Partnership recorded amortization expense of $4.8 million, or approximately $0.06 per unit, that relates to the minimum amortization.

The estimates of amortization expense for the periods as indicated below are based on current mining plans and are subject to revision as those plans change in future periods.

Estimated amortization expense (In thousands)	
For year ended December 31, 2011	$15,096
For year ended December 31, 2012	11,189
For year ended December 31, 2013	10,535
For year ended December 31, 2014	10,535
For year ended December 31, 2015	10,535

8. Long-Term Debt

Long-term debt consists of the following:

	December 31, 2010	December 31, 2009
	(In thousands)	
$300 million floating rate revolving credit facility, due March 2012	$ 94,000	$ 28,000
5.55% senior notes, with semi-annual interest payments in June and December, maturing June 2013	35,000	35,000
4.91% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2018	37,650	43,700
8.38% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2013, maturing in March 2019	150,000	150,000
5.05% senior notes, with semi-annual interest payments in January and July, with annual principal payments in July, maturing in July 2020	76,923	84,615
5.31% utility local improvement obligation, with annual principal and interest payments, maturing in March 2021	2,115	2,307
5.55% senior notes, with semi-annual interest payments in June and December, with annual principal payments in June, maturing in June 2023	36,900	40,200
5.82% senior notes, with semi-annual interest payments in March and September, with annual principal payments in March, maturing in March 2024	210,000	225,000
8.92% senior notes, with semi-annual interest payments in March and September, with scheduled principal payments beginning March 2014, maturing in March 2024	50,000	50,000
Total debt	692,588	658,822
Less — current portion of long term debt	(31,518)	(32,235)
Long-term debt	$661,070	$626,587

Principal payments due in:

	Senior Notes	Credit Facility	Total
		(In thousands)	
2011	$ 31,518	$ —	$ 31,518
2012	30,801	94,000	124,801
2013	87,230	—	87,230
2014	56,175	—	56,175
2015	56,175	—	56,175
Thereafter	336,689	—	336,689
	$598,588	$94,000	$692,588

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.

The 8.38% and 8.92% senior notes also provide that in the event that the Partnership's 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 Partnership made principal payments of $32.2 million and $17.2 million on its senior notes for the years ended December 31, 2010 and 2009, respectively.

The Partnership has a $300 million revolving credit facility, and at December 31, 2010, $206 million was available under the facility. The Partnership incurs a commitment fee on the undrawn portion of the revolving credit facility at rates ranging from 0.10% to 0.30% per annum. Under an accordion feature in the credit facility, the Partnership may request its lenders to increase their aggregate commitment to a maximum of $450 million on the same terms. However, the Partnership cannot be certain that its lenders will elect to participate in the accordion feature. To the extent the lenders decline to participate, the Partnership may elect to bring new lenders into the facility, but cannot make any assurance that the additional credit capacity will be available on existing or comparable terms.

The Partnership had $94.0 million and $28.0 million outstanding on its revolving credit facility at December 31, 2010 and 2009, respectively. The weighted average interest rate at December 31, 2010 and 2009 was 1.42% and 2.07%, respectively.

The revolving credit facility contains covenants requiring the Partnership 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.

The Partnership was in compliance with all terms under its long-term debt as of December 31, 2010.

9. Fair Value Measurements

The Partnership discloses certain assets and liabilities using fair value as defined by FASB's fair value authoritative guidance.

FASB's guidance describes three levels of inputs that may be used to measure fair value:

- Level 1 — Quoted prices in active markets for identical assets or liabilities.
- Level 2 — Observable inputs other than Level 1 prices, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.
- Level 3 — Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities. Level 3 assets and liabilities include financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation.

The Partnership's financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and long-term debt. The carrying amount of the Partnership's financial instruments included in accounts receivable and accounts payable approximates their fair value due to their short-term nature. The Partnership's cash and cash equivalents include money market accounts and are considered a Level 1 measurement. The fair market value of the Partnership's long-term debt was estimated to be $596.1 million and $627.5 million at December 31, 2010 and 2009, respectively, for the senior notes. The carrying value of the Partnership's senior notes was $598.6 million and $630.8 million at December 31, 2010 and 2009, respectively. The fair value is estimated by management using comparable term risk-free treasury issues with a market rate component determined by current financial instruments with similar characteristics which is a Level 3 measurement. Since the Partnership's credit facility is variable rate debt, its fair value approximates its carrying amount.

10. Incentive Distribution Rights

In connection with an acquisition, the holders of the IDRs elected to cap the distribution at Tier III for the quarters ending September 30, 2009 and December 31, 2009. The increase in basic and diluted net income per limited partner unit due to the forgone distributions for the year ended December 31, 2009 was $0.21 per unit.

On September 20, 2010, the Partnership eliminated all of the incentive distribution rights (IDRs) held by its general partner and affiliates of the general partner. As consideration for the elimination of the IDRs, the Partnership issued 32 million common units to the holders of the IDRs. As of the date of this report, there are 106,027,836 common units outstanding and the general partner has retained its 2% interest in the Partnership.

11. Related Party Transactions

Reimbursements to Affiliates of our General Partner

The Partnership's general partner does not receive any management fee or other compensation for its management of Natural Resource Partners L.P. However, in accordance with the partnership agreement, the general partner and its affiliates are reimbursed for expenses incurred on the Partnership's behalf. All direct general and administrative expenses are charged to the Partnership as incurred. The Partnership also reimburses 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.

The reimbursements to affiliates of the Partnership's general partner for services performed by Western Pocahontas Properties and Quintana Minerals Corporation are as follows:

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands)		
Reimbursement for services	$7,358	$6,822	$5,557

The Partnership leases substantially all of two floors of an office building in Huntington, West Virginia from Western Pocahontas Properties and pays $0.5 million in lease payments each year through December 31, 2018.

Transactions with Cline Affiliates

Various companies controlled by Chris Cline lease coal reserves from the Partnership, and the Partnership provides coal transportation services to them for a fee. Mr. Cline, both individually and through another affiliate, Adena Minerals, LLC, owns a 31% interest in the Partnership's general partner, as well as 21,017,441 common units. At December 31, 2010, the Partnership had accounts receivable totaling $6.5 million from Cline affiliates. Revenues from the Cline affiliates are as follows:

	For the Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Coal royalty revenues	$32,407	$23,325	$19,255
Coal processing fees	1,337	193	—
Transportation fees	14,324	11,495	6,895
Minimums recognized as revenue	12,400	—	—
Override revenue	1,904	2,356	1,788
	$62,372	$37,369	$27,938

As of December 31, 2010, the Partnership had received $47.0 million in minimum royalty payments that have not been recouped by Cline affiliates, of which $22.8 million was received in the current year.

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, the Partnership adopted a formal conflicts policy that establishes the opportunities that will be pursued by the Partnership 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. The Partnership currently has 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. The Partnership owns and leases the plants to Taggart Global, which designs, builds and operates the plants. The lease payments are based on the sales price for the coal that is processed through the facilities. To date, the Partnership has acquired four facilities under this agreement with Taggart with a total cost of $46.6 million. Revenues from Taggart are as follows:

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands)		
Coal processing revenue	$5,874	$3,872	$4,971

At December 31, 2010, the Partnership had accounts receivable totaling $1.3 million from Taggart.

A fund controlled by Quintana Capital owns Kopper-Glo, a small coal mining company that is one of the Partnership's lessees with operations in Tennessee. Revenues from Kopper-Glo are as follows:

	For the Years Ended December 31,		
	2010	2009	2008
	(In thousands)		
Coal royalty revenues	$1,545	$1,560	$1,445

At December 31, 2010, the Partnership also had accounts receivable totaling $0.1 million from Kopper-Glo.

12. Commitments and Contingencies

Legal

The Partnership is 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, Partnership management believes these claims will not have a material effect on the Partnership's financial position, liquidity or operations.

Environmental Compliance

The operations conducted on the Partnership's properties by its lessees are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. As owner of surface interests in some properties, the Partnership may be liable for certain environmental conditions occurring at the surface properties. The terms of substantially all of the Partnership's 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 the Partnership against, among other things, environmental liabilities. Some of these indemnifications survive the termination of the lease. The Partnership has neither incurred, nor is aware of, any material environmental charges imposed on it related to its properties as of December 31, 2010. The Partnership is not associated with any environmental contamination that may require remediation costs.

Acquisition

In conjunction with a definitive agreement, as of December 31, 2010, the Partnership may be obligated to purchase in excess of 143 million additional tons of coal reserves from Colt, LLC for an aggregate purchase price of $150.0 million as certain milestones are completed relating to construction of a new mine. See Footnote 14 — Subsequent Events, for further information regarding an additional acquisition of reserves after December 31, 2010.

13. Major Lessees

The Partnership has the following lessees that generated in excess of ten percent of total revenues in any one of the years ended December 31, 2010, 2009 and 2008. Revenues from these lessees are as follows:

	For the Years Ended December 31,					
	2010		2009		2008	
	Revenues	Percent	Revenues	Percent	Revenues	Percent
	(Dollars in thousands)					
The Cline Group	$62,372	20.7%	$37,369	14.6%	$27,938	9.6%
Massey Energy Company	$42,910	14.2%	$19,390	7.6%	$22,015	7.6%
Alpha Natural Resources	$36,175	12.0%	$28,941	11.3%	$37,400	12.8%

In 2010, the Partnership derived over 20% of its revenue from the Cline Group, 14% from Massey Energy Company and 12% from Alpha Natural Resources. Cline's Williamson mine alone was responsible for approximately 10% of our revenues in 2010. As a result, the Partnership has a significant concentration of revenues with those lessees, although in most cases, with the exception of Williamson, the exposure is spread out over a number of different mining operations and leases.

14. Incentive Plans

GP Natural Resource Partners LLC adopted the Natural Resource Partners Long-Term Incentive Plan (the "Long-Term Incentive Plan") for directors of GP Natural Resource Partners LLC and employees of its affiliates who perform services for the Partnership. The compensation committee of GP Natural Resource Partners LLC's board of directors administers the Long-Term Incentive Plan. Subject to the rules of the exchange upon which the common units are listed at the time, the board of directors and the compensation committee of the board of directors have the right to alter or amend the Long-Term Incentive Plan or any part of the Long-Term Incentive Plan from time to time. Except upon the occurrence of unusual or nonrecurring events, no change in any outstanding grant may be made that would materially reduce the benefit intended to be made available to a participant without the consent of the participant.

Under the plan a grantee will receive the market value of a common unit in cash upon vesting. Market value is defined as the average closing price over the 20 trading days prior to the vesting date. The compensation committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of the Partnership, the general partner, or GP Natural Resource Partners LLC. If a grantee's employment or membership on the board of directors terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the compensation committee provides otherwise.

A summary of activity in the outstanding grants for the year ended December 31, 2010 are as follows:

Outstanding grants at the beginning of the period	653,598
Grants during the period	236,548
Grants vested and paid during the period	(133,782)
Forfeitures during the period	(2,496)
Outstanding grants at the end of the period	753,868

Grants typically vest at the end of a four-year period and are paid in cash upon vesting. The liability fluctuates with the market value of the Partnership units and because of changes in estimated fair value determined each quarter using the Black-Scholes option valuation model. Risk free interest rates and historical volatility are reset at each calculation based on current rates corresponding to the remaining vesting term for each outstanding grant and ranged from 0.21% to 1.01% and 30.36% to 50.22%, respectively at December 31,

2010. The Partnership's historical dividend rate of 6.76% was used in the calculation at December 31, 2010. The Partnership accrued expenses related to its plans to be reimbursed to its general partner of $9.0 million and $10.6 million for the years ended December 31, 2010 and 2009, respectively. During 2008, the Partnership reversed accruals of approximately $0.3 million due to the decrease in unit price from December 31, 2007 to December 31, 2008. In connection with the Long-Term Incentive Plans, cash payments of $3.2 million, $2.9 million and $3.2 million were paid during each of the years ended December 31, 2010, 2009, and 2008, respectively. The grant date fair value was $29.42, $31.01 and $36.22 per unit for awards in 2010, 2009 and 2008, respectively and the unaccrued cost associated with the unvested outstanding grants at December 31, 2010 was $11.9 million.

In connection with the phantom unit awards granted in February 2008, 2009 and 2010, the compensation committee also granted tandem Distribution Equivalent Rights, or DERs, which entitle the holders to receive distributions equal to the distributions paid on the Partnership's common units during the vesting period. The DERs vest over the same period as the related phantom units, and the Partnership accrues the cost of the distributions over that period. The expense associated with the DERs is included in the LTIP accrual for each year.

15. Subsequent Events (Unaudited)

The following represents material events that have occurred subsequent to December 31, 2010 through the time of the Partnership's filing its Form 10-K with the Securities and Exchange Commission:

Acquisitions

On January 13, 2011, the Partnership closed the fourth acquisition of reserves from Colt, LLC, an affiliate of the Cline Group. The Partnership paid $70.0 million, funded through its credit facility, and acquired approximately 41.9 million tons of coal reserves.

On February 22, 2011, the Partnership acquired approximately 508 acres of mineral and surface rights related to limestone reserves in Livingston County, Kentucky for a purchase price of $16 million, $11 million of which was funded at closing.

Distributions

On January 19, 2011, the Partnership declared a distribution of $0.54 per unit to be paid on February 14, 2011 to unitholders of record on February 4, 2011.

16. Supplemental Financial Data (Unaudited)

Shown below are selected unaudited quarterly data. Amounts are rounded for consistency in presentation with no effect to the results of operations previously reported on Form 10-Q or Form 10-K.

Selected Quarterly Financial Information
(In thousands, except per unit data)

2010	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$63,519	$79,588	$80,752	$ 77,543
Income from operations	$40,912	$51,953	$50,344	$ 52,852
Net income	$30,191	$41,611	$40,153	$ 42,506
Basic and diluted net income per limited partner unit	$ 0.24	$ 0.38	$ 0.51	$ 0.39
Weighted average number of units outstanding:				
Common	69,451	74,028	77,896	106,028

2009	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$66,733	$59,487	$63,962	$65,902
Income from operations	$41,417	$27,661	$41,395	$43,502
Net income	$33,420	$17,082	$30,651	$32,927
Basic and diluted net income per limited partner unit	$ 0.33	$ 0.07	$ 0.36	$ 0.39
Weighted average number of units outstanding:				
Common	64,891	66,946	69,451	69,451

Second quarter 2009 net income decreased primarily due to lower revenues and a charge of $8.2 million in depletion expense related to a terminated lease from a mine closure.

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

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act) as of December 31, 2010. This evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and procedures are effective in producing the timely recording, processing, summary and reporting of information and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosures.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of GP Natural Resource Partners LLC, our managing general partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2010 based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2010. No changes were made to our internal control over financial reporting during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Ernst & Young, LLP, the independent registered public accounting firm who audited the Partnership's consolidated financial statements included in this Form 10-K, has issued a report on the Partnership's internal control over financial reporting, which is included herein.

Report of Independent Registered Public Accounting Firm

The Partners of Natural Resource Partners L.P.

We have audited Natural Resource Partners L.P.'s internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Natural Resource Partners L.P.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying "Management's Report on Internal Control Over Financial Reporting". Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Natural Resource Partners L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Natural Resource Partners L.P. as of December 31, 2010 and 2009, and the related consolidated statements of income, partners' capital and cash flows for each of the three years in the period ended December 31, 2010 of Natural Resource Partners L.P. and our report dated February 28, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 28, 2011

Item 9B. ***Other Information***

None.

PART III

Item 10. *Directors and Executive Officers of the Managing General Partner and Corporate Governance*

As a master limited partnership we do not employ any of the people responsible for the management of our properties. Instead, we reimburse affiliates of our managing general partner, GP Natural Resource Partners LLC, for their services. The following table sets forth information concerning the directors and officers of GP Natural Resource Partners LLC. Each officer and director is elected for their respective office or directorship on an annual basis. Unless otherwise noted below, the individuals served as officers or directors of the partnership since the initial public offering. 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.

Name	Age	Position with the General Partner
Corbin J. Robertson, Jr.	63	Chairman of the Board and Chief Executive Officer
Nick Carter	64	President and Chief Operating Officer
Dwight L. Dunlap	57	Chief Financial Officer and Treasurer
Kevin F. Wall	54	Executive Vice President — Operations
Wyatt L. Hogan	39	Vice President, General Counsel and Secretary
Dennis F. Coker	43	Vice President, Aggregates
Kevin J. Craig	42	Vice President, Business Development
Kenneth Hudson	56	Controller
Kathy H. Roberts	59	Vice President, Investor Relations
Robert T. Blakely	69	Director
David M. Carmichael	72	Director
J. Matthew Fifield	37	Director
Robert B. Karn III	69	Director
S. Reed Morian	65	Director
W. W. Scott, Jr.	66	Director
Stephen P. Smith	49	Director
Leo A. Vecellio, Jr.	64	Director

Corbin J. Robertson, Jr. has served as Chief Executive Officer and Chairman of the Board of Directors of GP Natural Resource Partners LLC since 2002. Mr. Robertson has vast business experience having founded and served as a director and as an officer of multiple companies, both private and public, and has served on the boards of numerous non-profit organizations. He has served as the Chief Executive Officer and Chairman of the Board of the general partners of Western Pocahontas Properties Limited Partnership since 1986, Great Northern Properties Limited Partnership since 1992, Quintana Minerals Corporation since 1978, and as Chairman of the Board of Directors of New Gauley Coal Corporation since 1986. He also serves as a Principal with Quintana Capital Group, Chairman of the Board of the Cullen Trust for Higher Education and on the boards of the American Petroleum Institute, the National Petroleum Council, the Baylor College of Medicine and the World Health and Golf Association. In 2006, Mr. Robertson was inducted into the Texas Business Hall of Fame.

Nick Carter has served as President and Chief Operating Officer of GP Natural Resource Partners LLC since 2002. He has also served as President of the general partner of Western Pocahontas Properties Limited Partnership and New Gauley Coal Corporation since 1990 and as President of the general partner of Great Northern Properties Limited Partnership from 1992 to 1998. Prior to 1990, Mr. Carter held various positions with MAPCO Coal Corporation and was engaged in the private practice of law. He is Chairman of the National Council of Coal Lessors, a past Chair of the West Virginia Chamber of Commerce and a board member of the Kentucky Coal Association, West Virginia Coal Association, Indiana Coal Council, National

Mining Association, ACCCE, Foundation for the Tri-State Community, Inc., Community Trust Bancorp, Inc., Vigo Coal Company, Inc. and Carbo*Prill, Inc.

Dwight L. Dunlap has served as the Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC since 2002. Mr. Dunlap has served as Vice President and Treasurer of Quintana Minerals Corporation and as Chief Financial Officer, Treasurer and Assistant Secretary of the general partner of Western Pocahontas Properties Limited Partnership, Chief Financial Officer and Treasurer of Great Northern Properties Limited Partnership and Chief Financial Officer, Treasurer and Secretary of New Gauley Coal Corporation since 2000. Mr. Dunlap has worked for Quintana Minerals since 1982 and has served as Vice President and Treasurer since 1987. Mr. Dunlap is a Certified Public Accountant with over 30 years of experience in financial management, accounting and reporting including six years of audit experience with an international public accounting firm.

Kevin F. Wall has served as Executive Vice President — Operations of GP Natural Resource Partners LLC since 2008. Mr. Wall was promoted to Executive Vice President — Operations in December 2008. Prior to then he served as Vice President — Engineering for GP Natural Resource Partners LLC from 2002-2008, the general partner of Western Pocahontas Properties Limited Partnership since 1998 and the general partner of Great Northern Properties Limited Partnership since 1992. He has also served as the Vice President — Engineering of New Gauley Coal Corporation since 1998. He has performed duties in the land management, planning, project evaluation, acquisition and engineering areas since 1981. He is a Registered Professional Engineer in West Virginia and is a member of the American Institute of Mining, Metallurgical, and Petroleum Engineers and of the National Society of Professional Engineers. Mr. Wall also serves on the Board of Directors of Leadership Tri-State as well as the Board of the Virginia Center for Coal and Energy Research and is a past president of the West Virginia Society of Professional Engineers.

Wyatt L. Hogan has served as Vice President, General Counsel and Secretary of GP Natural Resource Partners LLC since 2003. Mr. Hogan joined NRP in May 2003 from Vinson & Elkins L.L.P., where he practiced corporate and securities law from August 2000 through April 2003. He has also served since 2003 as the Vice President, General Counsel and Secretary of Quintana Minerals Corporation, the Secretary for the general partner of Western Pocahontas Properties Limited Partnership and as General Counsel and Secretary for the general partner of Great Northern Properties Limited Partnership. He is also member of the Board of Directors of Quintana Minerals Corporation. Prior to joining Vinson & Elkins in August 2000, he practiced corporate and securities law at Andrews & Kurth L.L.P. from September 1997 through July 2000.

Dennis F. Coker is Vice President, Aggregates of GP Natural Resource Partners LLC. Mr. Coker joined NRP in March 2008 from Hanson Building Materials America, where he had been employed since 2002, and most recently served as Director, Corporate Development. Mr. Coker has 14 years of experience in the aggregate industry, with the last eleven years focused on business development activity. He formerly served as Chairman of the Young Leaders Council of the National Stone Sand and Gravel Association.

Kevin J. Craig is the Vice President of Business Development for GP Natural Resource Partners LLC. Mr. Craig joined NRP in 2005 from CSX Transportation, where he served as Terminal Manager for the West Virginia Coalfields. He has extensive marketing and finance experience with CSX since 1996. Mr. Craig also serves as a Delegate to the West Virginia House of Delegates having been elected in 2000 and re-elected in 2002, 2004, 2006, 2008 and 2010. Mr. Craig currently serves as Vice Chairman of the Committee on Economic Development. Prior to joining CSX, he served as a Captain in the United States Army.

Kenneth Hudson has served as the Controller of GP Natural Resource Partners LLC since 2002. He has served as Controller of the general partner of Western Pocahontas Properties Limited Partnership and of New Gauley Coal Corporation since 1988 and of the general partner of Great Northern Properties Limited Partnership since 1992. He was also Controller of Blackhawk Mining Co., Quintana Coal Co. and other related operations from 1985 to 1988. Prior to that time, Mr. Hudson worked in public accounting.

Kathy H. Roberts is Vice President, Investor Relations of GP Natural Resource Partners LLC. Ms. Roberts joined NRP in July 2002. She was the Principal of IR Consulting Associates from 2001 to July 2002 and from 1980 through 2000 held various financial and investor relations positions with Santa Fe Energy Resources, most recently as Vice President — Public Affairs. She is a Certified Public Accountant. Ms. Roberts currently serves on the Board of Directors of the National Association of Publicly Traded Partnerships and has served on the local board of directors of the National Investor Relations Institute and maintained professional affiliations with various energy industry organizations. She has also served on the Executive Committee and as a National Vice President of the Institute of Management Accountants.

Robert T. Blakely joined the Board of Directors of GP Natural Resource Partners LLC in January 2003. Mr. Blakely has extensive public company experience having served as Executive Vice President and Chief Financial Officer for several companies. From January 2006 until August 2007, he served as Executive Vice President and Chief Financial Officer of Fannie Mae, and from August 2007 to January 2008 as an Executive Vice President at Fannie Mae. From mid-2003 through January 2006, he was Executive Vice President and Chief Financial Officer of MCI, Inc. He previously served as Executive Vice President and Chief Financial Officer of Lyondell Chemical from 1999 through 2002, Executive Vice President and Chief Financial Officer of Tenneco, Inc. from 1981 until 1999 as well as a Managing Director at Morgan Stanley. He currently serves as a Trustee of the Financial Accounting Federation and is a trustee emeritus of Cornell University. He has served on the Board of Westlake Chemical Corporation since August 2004. In 2009, Mr. Blakely joined the Boards of Directors of Ally Financial (formerly GMAC, Inc.), where he serves as Chairman of the Audit Committee, and Greenhill & Co.

David M. Carmichael joined the Board of Directors of GP Natural Resource Partners LLC in 2002. While Mr. Carmichael has been a private investor since June 1996, he has formerly served as Chairman and Chief Executive Officer at several public companies and currently serves on the board of directors of two public companies. Between 1994 and 1996, he served as Vice Chairman and Chairman of the Management Committee of KN Energy, Inc., a predecessor to Kinder Morgan, Inc. From 1985 until its merger with KN Energy, Inc. in 1994, Mr. Carmichael served as Chairman, Chief Executive Officer and President of American Oil and Gas Corporation. He formed CARCON Corporation in 1984, where he served as President and Chief Executive Officer until its merger into American Oil and Gas Corporation in 1986. From 1976 to 1984, Mr. Carmichael was Chairman and Chief Executive Officer of WellTech, Inc. He served in various senior management positions with Reading and Bates Corporation between 1965 and 1976. He served on the Board of Directors of ENSCO International from 2001 to 2010, Cabot Oil and Gas since 2006, and Tom Brown, Inc. from 1997 until 2004. Mr. Carmichael serves on the Nominating and Governance Committee and the Compensation Committee for Cabot and on the Compensation, Nominating and Governance Committees for ENSCO. He also currently serves as a trustee of the Texas Heart Institute.

J. Matthew Fifield is a member of the Board of Directors of GP Natural Resource Partners LLC. Mr. Fifield brings coal mining and financial experience to NRP's board of directors. Mr. Fifield joined NRP's Board of Directors in January 2007. He currently serves as a Managing Director of Foresight Management, LLC, a Cline Group affiliate and is responsible for business development and as a Managing Director of Gogebic Taconite, LLC, a development stage iron mining company, a Cline Group affiliate. Since 2005, he has also served as a Managing Director of both Adena Minerals, LLC and Cline Resource & Development Company, both Cline Group affiliates. Prior to joining the Cline Group, Mr. Fifield worked at Resource Capital Funds, a private equity firm focused on metals and mining, in 2004 and 2005. From 1997 to 2000, Mr. Fifield worked in various positions with UBS Warburg, focusing on metals and minerals.

Robert B. Karn III joined the Board of Directors of GP Natural Resource Partners LLC in 2002. Mr. Karn brings extensive financial and coal industry experience to the board of directors. He currently is a consultant and serves on the Board of Directors of various entities. He was the partner in charge of the coal mining practice worldwide for Arthur Andersen from 1981 until his retirement in 1998. He retired as Managing Partner of the St. Louis office's Financial and Economic Consulting Practice. Mr. Karn is a Certified Public Accountant, Certified Fraud Examiner and has served as president of numerous organizations. He also currently serves on the Board of Directors of Peabody Energy Corporation, Kennedy Capital Management, Inc. and the Board of Trustees of numerous publicly listed closed-end, exchange traded funds of the Guggenheim family of funds.

S. Reed Morian joined the Board of Directors of GP Natural Resource Partners LLC in 2002. Mr. Morian has vast executive business experience having served as Chairman and Chief Executive Officer of several companies since the early 1980s and serving on the board of other companies. Mr. Morian has served as a member of the Board of Directors of the general partner of Western Pocahontas Properties Limited Partnership since 1986, New Gauley Coal Corporation since 1992 and the general partner of Great Northern Properties Limited Partnership since 1992. Mr. Morian worked for Dixie Chemical Company from 1971 to 2006 and served as its Chairman and Chief Executive Officer from 1981 to 2006. He has also served as Chairman, Chief Executive Officer and President of DX Holding Company since 1989. He formerly served on the Board of Directors for the Federal Reserve Bank of Dallas-Houston Branch from April 2003 until December 2008 and as a Director of Prosperity Bancshares, Inc. from March 2005 until April 2009.

W. W. Scott, Jr. joined the Board of Directors of GP Natural Resource Partners LLC in 2002. Mr. Scott has extensive experience both as a commercial banker and as a Chief Financial Officer. Mr. Scott joined Mr. Robertson's various companies in the mid-1980s, and retired in 1999. Mr. Scott was Executive Vice President and Chief Financial Officer of Quintana Minerals Corporation from 1985 to 1999. He served as Executive Vice President and Chief Financial Officer of the general partner of Western Pocahontas Properties Limited Partnership and New Gauley Coal Corporation from 1986 to 1999. He served as Executive Vice President and Chief Financial Officer of the general partner of Great Northern Properties Limited Partnership from 1992 to 1999. Since 1999, he has continued to serve as a director of the general partner of Western Pocahontas Properties Limited Partnership and Quintana Minerals Corporation.

Stephen P. Smith joined the Board of Directors of GP Natural Resource Partners LLC in 2004. Mr. Smith brings extensive public company financial experience in the power and energy industries to the board of directors. Mr. Smith has been the Executive Vice President and Chief Financial Officer for NiSource, Inc. since June 2008. Prior to joining NiSource, he held several positions with American Electric Power Company, Inc, including Senior Vice President — Shared Services from January 2008 to June 2008, Senior Vice President and Treasurer from January 2004 to December 2007, and Senior Vice President — Finance from April 2003 to December 2003. From November 2000 to January 2003, Mr. Smith served as President and Chief Operating Officer — Corporate Services for NiSource Inc. Prior to joining NiSource, Mr. Smith served as Deputy Chief Financial Officer for Columbia Energy Group from November 1999 to November 2000 and Chief Financial Officer for Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company from 1996 to 1999.

Leo A. Vecellio, Jr. joined the Board of Directors of GP Natural Resource Partners LLC in May 2007. Mr. Vecellio brings extensive experience in the aggregates and coal mine development industry to the board of directors. Mr. Vecellio and his family have been in the aggregates materials and construction business since the late 1930s. Since November 2002, Mr. Vecellio has served as Chairman and Chief Executive Officer of Vecellio Group, Inc, a major aggregates producer, contractor and oil terminal developer/operator in the Mid-Atlantic and Southeastern states. For nearly 30 years prior to that time Mr. Vecellio served in various capacities with Vecellio & Grogan, Inc., having most recently served as Chairman and Chief Executive Officer from April 1996 to November 2002. Mr. Vecellio is the former Chairman of the American Road and Transportation Builders and is a longtime member of the Florida Council of 100, as well as many other civic and charitable organizations.

Corporate Governance

Board Attendance and Executive Sessions

The Board of Directors met nine times in 2010. During that period, every director attended all of the board meetings, with the exception of Mr. Fifield, who was excused from one meeting that involved discussions of an acquisition from the Cline Group, and Messrs. Vecellio and Smith, who each missed one meeting. Pursuant to our Corporate Governance Guidelines, the non-management directors meet in executive session on a quarterly basis. During 2010, our non-management directors met in executive session four times. The presiding director of these meetings was David Carmichael, the Chairman of our Compensation, Nominating and Governance Committee, or CNG Committee. In addition, our independent directors met one time in executive session in 2010. Mr. Carmichael was the presiding director at this meeting. Interested parties may communicate with our non-management directors by writing a letter to the Chairman of the CNG Committee, NRP Board of Directors, 601 Jefferson St., Suite 3600, Houston, Texas 77002.

Independence of Directors

The Board of Directors has affirmatively determined that Messrs. Blakely, Carmichael, Karn, Smith and Vecellio are independent based on all facts and circumstances considered by the board, including the standards set forth in Section 303A.02(a) of the New York Stock Exchange's listing standards. Although we had a majority of independent directors in 2010, because we are a limited partnership as defined in Section 303A of the New York Stock Exchange's listing standards, we are not required to do so. The Board has an Audit Committee, Compensation, Nominating and Governance Committee and Conflicts Committee, each of which is staffed solely by independent directors. Our Audit Committee is comprised of Robert B. Karn III, who serves as chairman, Robert T. Blakely, Stephen P. Smith and David M. Carmichael. Mr. Karn, Mr. Smith and Mr. Blakely are "Audit Committee Financial Experts" as determined pursuant to Item 407 of Regulation S-K. In addition to his service on our audit committee and the audit committee for Westlake Chemical Corporation, in 2009 Mr. Blakely joined the audit committees of two additional public companies. In accordance with the rules of the New York Stock Exchange, our Board of Directors has made the determination that Mr. Blakely's service on four audit committees does not impair his ability to serve effectively on our audit committee.

Report of the Audit Committee

Our Audit Committee is composed entirely of independent directors. The members of the Audit Committee meet the independence and experience requirements of the New York Stock Exchange. The Committee has adopted, and annually reviews, a charter outlining the practices it follows. The charter complies with all current regulatory requirements.

During the year 2010, at each of its meetings, the Committee met with the senior members of our financial management team, our general counsel and our independent auditors. The Committee had private sessions at certain of its meetings with our independent auditors at which candid discussions of financial management, accounting and internal control issues took place.

The Committee approved the engagement of Ernst & Young LLP as our independent auditors for the year ended December 31, 2010 and reviewed with our financial managers and the independent auditors overall audit scopes and plans, the results of internal and external audit examinations, evaluations by the auditors of our internal controls and the quality of our financial reporting.

Management has reviewed the audited financial statements in the Annual Report with the Audit Committee, including a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant accounting judgments and estimates, and the clarity of disclosures in the financial statements. In addressing the quality of management's accounting judgments, members of the Audit Committee asked for management's representations and reviewed certifications prepared by the Chief Executive Officer and Chief Financial Officer that our unaudited quarterly and audited consolidated financial statements fairly present, in all material respects, our financial condition and results of operations, and have expressed to both management and auditors their general preference for conservative policies when a range of accounting options is available.

The Committee also discussed with the independent auditors other matters required to be discussed by the auditors with the Committee by PCAOB Auditing Standard AU Section 380, *Communication With Audit Committees.* The Committee received and discussed with the auditors their annual written report on their independence from the partnership and its management, which is made under Rule 3526, *Communication With Audit Committees Concerning Independence,* and considered with the auditors whether the provision of non-audit services provided by them to the partnership during 2010 was compatible with the auditors' independence.

In performing all of these functions, the Audit Committee acts only in an oversight capacity. The Committee reviews our quarterly and annual reporting on Form 10-Q and Form 10-K prior to filing with the Securities and Exchange Commission. In 2010, the Committee also reviewed quarterly earnings announcements with management and representatives of the independent auditor in advance of their issuance. In its oversight role, the Committee relies on the work and assurances of our management, which has the primary responsibility for financial statements and reports, and of the independent auditors, who, in their report, express an opinion on the conformity of our annual financial statements with U.S. generally accepted accounting principles.

In reliance on these reviews and discussions, and the report of the independent auditors, the Audit Committee has recommended to the Board of Directors, and the Board has approved, that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2010, for filing with the Securities and Exchange Commission.

Robert B. Karn III, Chairman
Robert T. Blakely
Stephen P. Smith
David M. Carmichael

Compensation, Nominating and Governance Committee Authority

Executive officer compensation is administered by the CNG Committee, which is comprised of four members. Mr. Carmichael, the Chairman, and Mr. Karn have served on this committee since 2002, Mr. Blakely joined the committee in early 2003, and Mr. Vecellio joined the committee in 2007. The CNG Committee has reviewed and approved the compensation arrangements described in the Compensation Discussion and Analysis section of this Form 10-K. Our board of directors appoints the CNG Committee and delegates to the CNG Committee responsibility for:

- reviewing and approving the compensation for our executive officers in light of the time that each executive officer allocates to our business;
- reviewing and recommending the annual and long-term incentive plans in which our executive officers participate; and
- reviewing and approving compensation for the board of directors.

Our board of directors has determined that each committee member is independent under the listing standards of the New York Stock Exchange and the rules of the Securities and Exchange Commission.

Pursuant to its charter, the CNG Committee is authorized to obtain at NRP's expense compensation surveys, reports on the design and implementation of compensation programs for directors and executive officers and other data that the CNG Committee considers as appropriate. In addition, the CNG Committee has the sole authority to retain and terminate any outside counsel or other experts or consultants engaged to assist it in the evaluation of compensation of our directors and executive officers.

***Section 16*(a) Beneficial Ownership Reporting Compliance**

Section 16(a) of the Securities and Exchange Act of 1934 requires directors, officers and persons who beneficially own more than ten percent of a registered class of our equity securities to file with the SEC and the New York Stock Exchange initial reports of ownership and reports of changes in ownership of their equity securities. These people are also required to furnish us with copies of all Section 16(a) forms that they file. Based solely upon a review of the copies of Forms 3, 4 and 5 furnished to us, or written representations from certain reporting persons that no Forms 5 were required in 2010, we believe that our officers and directors and persons who beneficially own more than ten percent of a registered class of our equity securities complied with all filing requirements with respect to transactions in our equity securities during 2010, with the exception of Adena Minerals and Mr. Scott, who each had one late Form 4.

Partnership Agreement

Investors may view our partnership agreement and the amendments to the partnership agreement on our website at *www.nrplp.com*. The partnership agreement and the amendments are also filed with the Securities and Exchange Commission and are available in print to any unitholder that requests them.

Corporate Governance Guidelines and Code of Business Conduct and Ethics

We have adopted Corporate Governance Guidelines. We have also adopted a Code of Business Conduct and Ethics that applies to our management, and complies with Item 406 of Regulation S-K. Our Corporate Governance Guidelines and our Code of Business Conduct and Ethics are available on the internet at *www.nrplp.com* and are available in print upon request.

NYSE Certification

Pursuant to Section 303A of the NYSE Listed Company Manual, in 2010, Corbin J. Robertson, Jr. certified to the NYSE that he was not aware of any violation by the Partnership of NYSE corporate governance listing standards.

Item 11. *Executive Compensation*

Compensation Discussion and Analysis

Overview

As a publicly traded partnership, we have a unique employment and compensation structure that is different from that of a typical public corporation. We have no employees, and our executive officers based in Houston, Texas are employed by Quintana Minerals Corporation and our executive officers based in Huntington, West Virginia are employed by Western Pocahontas Properties Limited Partnership, both of which are our affiliates. For a more detailed description of our structure, please see "Item 1. Business — Partnership Structure and Management" in this Form 10-K. Although our executives' salaries and bonuses are paid directly by the private companies that employ them, we reimburse those companies based on the time allocated to NRP by each executive officer. Our reimbursement for the compensation of executive officers is governed by our partnership agreement.

Executive Officer Compensation Strategy and Philosophy

Under our partnership agreement, we are required to distribute all of our available cash each quarter. Our primary business objective is to generate cash flows at levels that can sustain long-term quarterly cash distributions to our investors. Our executive officer compensation strategy has been designed to motivate and retain our executive officers and to align their interests with those of our unitholders. Our primary objective in determining the compensation of our executive officers is to encourage them to build the partnership in a way that ensures long-term increased cash distributions to our unitholders and growth in our asset base while maintaining the long-term stability of the partnership. We do not tie our compensation to achievement of specific financial targets or fixed performance criteria, but rather evaluate the appropriate compensation on an annual basis in light of our overall business objectives.

In accordance with our objective of sustaining and increasing the quarterly distribution over the long-term, we believe that optimal alignment between our unitholders and our executive officers is best achieved by compensating our executive officers through sharing a percentage of distributions received by our general partner and through distribution equivalent rights tied to long-term equity-based compensation. Our compensation for executive officers consists of four primary components:

- base salaries;
- annual cash incentive awards, including bonuses and cash payments made by our general partner based on a percentage of the cash it receives from common units that the general partner owns;

- long-term equity incentive compensation; and
- perquisites and other benefits.

Mr. Robertson does not receive a salary or an annual bonus in his capacity as CEO. Rather, for the reasons discussed in greater detail below, Mr. Robertson is compensated exclusively through long-term phantom unit grants awarded by the CNG Committee and through sharing a percentage of the distributions received by the general partner. Mr. Robertson also directly or indirectly owns in excess of 20% of the outstanding units of NRP, and thus his interests are directly aligned with our unitholders.

In December 2010, our CNG Committee reviewed the performance of the executive officers and the amount of time expected to be spent by each NRP officer on NRP business. All of our executive officers other than Mr. Robertson spend nearly 90% or more of their time on NRP matters and NRP bears the allocated cost of their time spent on NRP matters. Mr. Robertson has historically spent approximately 50% of his time on NRP matters. Based on its review, the CNG Committee approved an average increase of 3.5% in the salaries of the executive officers in 2011 other than Mr. Robertson.

In February 2011, the CNG Committee met to approve the year-end bonuses and long-term incentive awards for the executive officers. The CNG Committee considered the performance of the partnership, the performance of the individuals and the outlook for the future in determining the amounts of the awards. Because we are a partnership, tax and accounting conventions make it more costly for us to issue additional common units or options as incentive compensation. Consequently, we have no outstanding options or restricted units and have no plans to issue options or restricted units in the future. Instead, we have issued phantom units to our executive officers that are paid in cash based on the average closing price of our common units for the 20-day trading period prior to vesting. The phantom units typically vest four years from the date of grant. In connection with the phantom unit awards granted in 2008-2011, the CNG Committee also granted tandem Distribution Equivalent Rights, or DERs, which entitle the holders to receive distributions equal to the distributions paid on our common units. The DERs have a four-year vesting period. Through these awards, each executive officer's interest is aligned with those of our unitholders in sustaining and increasing our quarterly cash distributions over the long-term, increasing the value of our common units, and maintaining a steady growth profile for NRP.

Role of Compensation Experts

The CNG Committee did not retain any consultants to evaluate compensation of officers or directors in 2010. The CNG Committee periodically has utilized consultants to get a basic sense of the market, but has considered the advice of the consultant as only one factor among the other items discussed in this compensation discussion and analysis. For a more detailed description of the CNG Committee and its responsibilities, please see "Item 10. Directors and Executive Officers of the Managing General Partner and Corporate Governance" in this Form 10-K.

Role of Our Executive Officers in the Compensation Process

Mr. Robertson and Mr. Carter provided recommendations to the CNG Committee in its evaluation of the 2010 compensation programs for our executive officers. Mr. Carter provided Mr. Robertson with recommendations relating to the executive officers, other than himself, that are based in Huntington. Mr. Robertson considered those recommendations and provided the CNG Committee with recommendations for all of the executive officers, including the Houston-based officers other than himself. Mr. Robertson and Mr. Carter relied on their personal experience in setting compensation over a number of years in determining the appropriate amounts for each employee, and considered each of the factors described elsewhere in this compensation discussion and analysis. Mr. Robertson and Mr. Carter attended the CNG Committee meetings at which the committee deliberated and approved the compensation, but were excused from the meetings when the CNG Committee discussed their compensation. No other named executive officer assumed an active role in the evaluation or design of the 2010 executive officer compensation programs.

Components of Compensation

Base Salaries

With the exception of Mr. Robertson, who, as described above, does not receive a salary for his services as Chief Executive Officer, our named executive officers are paid an annual base salary by Quintana and Western Pocahontas for services rendered to us by the executive officers during the fiscal year. We then reimburse Quintana and Western Pocahontas based on the time allocated by each executive officer to our business. The base salaries of our named executive officers are reviewed on an annual basis as well as at the time of a promotion or other material change in responsibilities. The CNG Committee reviews and approves the full salaries paid to each executive officer by Quintana and Western Pocahontas, based on both the actual time allocations to NRP in the prior year and the anticipated time allocations in the coming year. Adjustments in base salary are based on an evaluation of individual performance, our partnership's overall performance during the fiscal year and the individual's contribution to our overall performance.

Annual Cash Incentive Awards

Each executive officer, other than Mr. Robertson, participated in two cash incentive programs in 2010. The first program is a discretionary cash bonus award approved in February 2011 by the CNG Committee based on the same criteria used to evaluate the annual base salaries. The bonuses awarded with respect to 2010 under this program are disclosed in the Summary Compensation Table under the Bonus column. As with the base salaries, there are no formulas or specific performance targets related to these awards. Although we did not increase the quarterly distribution in 2010, NRP investors that held units from January 1 to December 31 received a total return of 46%. We outperformed our public guidance for the year, and exceeded most analyst expectations. In addition, we positioned the partnership for long-term distribution growth by eliminating the incentive distribution rights, thereby lowering the cost of capital for future acquisitions. NRP also made several accretive acquisitions during the year. These factors were considered by the CNG Committee in determining to award higher bonuses to the executive officers in 2010 versus 2009.

Under the second cash incentive program, our general partner has set aside 7.5% of the cash distributions it receives on an annual basis with respect to distributions on common units held by our general partner for awards to our executive officers, including Mr. Robertson. Although Mr. Robertson has the discretion to determine the amount of the 7.5% that is allocated to each executive officer, the cash awards that our officers receive under this plan are reviewed by the CNG Committee and taken into account when making determinations with respect to salaries, bonuses and long-term incentive awards. Because they are ultimately reimbursed by the general partner and not NRP, the incentive payments made with respect to this program do not have any impact on our financial statements or cash available for distribution to our unitholders. Since the cost of these awards is not borne by NRP, we have not disclosed the amounts of these awards in the Summary Compensation Table, but have included the amounts separately in a footnote to the table. We believe that these awards align the interests of our executive officers directly with our unitholders.

Long-Term Incentive Compensation

At the time of our initial public offering, we adopted the Natural Resource Partners Long-Term Incentive Plan for our directors and all the employees who perform services for NRP, including the executive officers. We consider long-term equity-based incentive compensation to be the most important element of our compensation program for executive officers because we believe that these awards keep our officers focused on the growth of NRP, particularly the sustainability and long-term growth of quarterly distributions and their impact on our unit price, over an extended time horizon.

Consistent with this approach, in 2008 our CNG Committee recommended, and our Board approved, an amendment to our Long-Term Incentive Plan to add distribution equivalent rights as a possible award to be granted under the plan. The distribution equivalent rights are contingent rights, granted in tandem with phantom units, to receive an amount in cash equal to the cash distributions made by NRP with respect to the common units during the period in which the phantom units are outstanding.

Our CNG Committee has generally approved annual awards of phantom units that vest four years from the date of grant. The amounts included in the compensation table reflect the grant date fair value of the unit awards determined in accordance with Financial Accounting Standards Board stock compensation authoritative guidance. We have structured the phantom unit awards so that our executive officers and directors directly benefit along with our unitholders when our unit price increases, and experience reductions in the value of their incentive awards when our unit price declines.

In connection with its review of incentive compensation in February 2011, the CNG Committee determined to increase the annual phantom unit grants to each of the named executive officers.

Perquisites and Other Personal Benefits

Both Quintana and Western Pocahontas maintain employee benefit plans that provide our executive officers and other employees with the opportunity to enroll in health, dental and life insurance plans. Each of these benefit plans require the employee to pay a portion of the health and dental premiums, with the company paying the remainder. These benefits are offered on the same basis to all employees of Quintana and Western Pocahontas, and the company costs are reimbursed by us to the extent the employee allocates time to our business.

Quintana and Western Pocahontas also maintain 401(k) and defined contribution retirement plans. Quintana matches 100% of the first 4.5% of the employee contributions under the 401(k) plan and Western Pocahontas matches the employee contributions at a level of 100% of the first 3% of the contribution and 50% of the next 3% of the contribution. In addition, each company contributes $\frac{1}{12}$ of each employee's base salary to the defined contribution retirement plan on an annual basis. As with the other contributions, any amounts contributed by Quintana and Western Pocahontas are reimbursed by us based on the time allocated by the employee to our business. The payments made to Messrs. Carter, Dunlap, Hogan and Wall under the defined contribution plan exceeded $10,000 in each of 2008, 2009 and 2010, but did not exceed $20,000 for any individual in any year. None of NRP, Quintana or Western Pocahontas maintain a pension plan or a defined benefit retirement plan. As noted in the Summary Compensation Table, in 2008, 2009 and 2010 we also reimbursed Quintana and Western Pocahontas for car allowances provided to Messrs. Carter, Dunlap and Wall.

Unit Ownership Requirements

We do not have any policy or guidelines that require specified ownership of our common units by our directors or executive officers or unit retention guidelines applicable to equity-based awards granted to directors or executive officers. As of December 31, 2010, our named executive officers held 254,000 phantom units that have been granted as compensation. In addition, Mr. Robertson directly or indirectly owns in excess of 20% of the outstanding units of NRP.

Securities Trading Policy

Our insider trading policy states that executive officers and directors may not purchase or sell puts or calls to sell or buy our units, engage in short sales with respect to our units, or buy our securities on margin.

Tax Implications of Executive Compensation

Because we are a partnership, Section 162(m) of the Internal Revenue Code does not apply to compensation paid to our named executive officers and accordingly, the CNG Committee did not consider its impact in determining compensation levels in 2008, 2009 or 2010. The CNG Committee has taken into account the tax implications to the partnership in its decision to limit the long-term incentive compensation to phantom units as opposed to options or restricted units.

Accounting Implications of Executive Compensation

The CNG Committee has considered the partnership accounting implications, particularly the "book-up" cost, of issuing equity as incentive compensation, and has determined that phantom units offer the best accounting treatment for the partnership while still motivating and retaining our executive officers.

Report of the Compensation, Nominating and Governance Committee

The CNG Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management. Based on the reviews and discussions referred to in the foregoing sentence, the CNG Committee recommended to the board of directors that the Compensation Discussion and Analysis be included in our Annual Report on Form 10-K for the year ended December 31, 2010.

David M. Carmichael, Chairman
Robert B. Karn III
Robert T. Blakely
Leo A. Vecellio, Jr.

Summary Compensation Table

The following table sets forth the amounts reimbursed to affiliates of our general partner for compensation expense in 2008, 2009 and 2010 based on time allocated by each individual to Natural Resource Partners. In 2010, Messrs. Robertson, Dunlap, Carter, Hogan and Wall spent approximately 50%, 93%, 97%, 92% and 95% of their time on NRP matters.

Name and Principal Position	Year	Salary ($)	Bonus ($)	Phantom Unit Awards(1) ($)	All Other Compensation(2) ($)	Total ($)
Corbin J. Robertson, Jr.	2010	—	—	783,090	—	783,090
Chairman and CEO	2009	—	—	817,600	—	817,600
	2008	—	—	642,400	—	642,400
Dwight L. Dunlap	2010	298,427	140,000	189,840	36,037	664,304
CFO and Treasurer	2009	301,493	105,000	186,880	36,407	629,780
	2008	253,843	140,000	224,840	32,287	650,970
Nick Carter	2010	358,900	220,000	332,220	39,229	950,349
President and COO	2009	358,900	165,000	327,040	39,229	890,169
	2008	320,100	220,000	321,200	37,353	898,653
Wyatt L. Hogan	2010	295,403	140,000	189,840	29,025	654,268
Vice President, General	2009	284,979	105,000	186,880	28,001	604,860
Counsel and Secretary	2008	257,380	140,000	224,840	27,133	649,353
Kevin F. Wall	2010	190,000	140,000	189,840	31,794	551,634
Executive Vice President —	2009	190,000	105,000	186,880	31,794	513,674
Operations	2008	147,242	140,000	224,840	26,300	538,382

(1) Amounts represent the grant date fair value of unit awards determined in accordance with Financial Accounting Standard Board stock compensation authoritative guidance.

(2) Includes portions of automobile allowance, 401(k) matching and retirement contributions allocated to Natural Resource Partners by Quintana Minerals Corporation and Western Pocahontas Properties Limited Partnership. The payments made to Messrs. Carter, Dunlap, Hogan and Wall under the defined contribution plan exceeded $10,000 in each of 2008, 2009 and 2010, but did not exceed $20,000 for any individual in any year. The table does not include any cash compensation paid by the general partner to each named executive officer. The general partner may distribute up to 7.5% of any cash it receives with respect to the common units that it received in connection with the elimination of the incentive distribution rights. We

do not reimburse the general partner for any of these payments, and the payments are not an expense of NRP. The table below shows the amounts paid by the general partner that are not reimbursed by NRP.

Individual	Year	Compensation Received from General Partner and Not Reimbursed by NRP $
Corbin J. Robertson, Jr.	2010	380,000
	2009	310,000
	2008	300,000
Dwight L. Dunlap	2010	277,500
	2009	226,000
	2008	216,000
Nick Carter	2010	380,000
	2009	310,000
	2008	300,000
Wyatt L. Hogan	2010	277,500
	2009	226,000
	2008	216,000
Kevin F. Wall	2010	277,500
	2009	226,000
	2008	216,000

Grants of Plan-Based Awards in 2010

Named Executive Officer	Grant Date	All Other Unit Awards: Number of Phantom Units(1) (#)	Grant Date Fair Value of Unit Awards(2) ($)
Corbin J. Robertson, Jr.	2/11/2010	33,000	783,090
Dwight L. Dunlap	2/11/2010	8,000	189,840
Nick Carter	2/11/2010	14,000	332,220
Wyatt L. Hogan	2/11/2010	8,000	189,840
Kevin F. Wall	2/11/2010	8,000	189,840

(1) The phantom units were granted in February 2010 and will vest in February 2014.

(2) Amounts represent the estimated fair value on February 11, 2010.

None of our executive officers has an employment agreement, and the salary, bonus and phantom unit awards noted above are approved by the CNG Committee. Please see our disclosure in the Compensation Discussion and Analysis section of this Form 10-K for a description of the factors that the CNG Committee considers in determining the amount of each component of compensation.

Subject to the rules of the exchange upon which the common units are listed at the time, the board of directors and the CNG Committee have the right to alter or amend the Long-Term Incentive Plan or any part of the Long-Term Incentive Plan from time to time. Except upon the occurrence of unusual or nonrecurring events, no change in any outstanding grant may be made that would materially reduce any award to a participant without the consent of the participant.

The CNG Committee may make grants under the Long-Term Incentive Plan to employees and directors containing such terms as it determines, including the vesting period. Outstanding grants vest upon a change in control of NRP, our general partner or GP Natural Resource Partners LLC. If a grantee's employment or membership on the board of directors terminates for any reason, outstanding grants will be automatically forfeited unless and to the extent the compensation committee provides otherwise.

As stated above in the Compensation Discussion and Analysis, we have no outstanding option grants, and do not intend to grant any options or restricted unit awards in the future. The CNG Committee regularly makes awards of phantom units on an annual basis in February.

Outstanding Awards at December 31, 2010

The table below shows the total number of outstanding phantom units held by each named executive officer at December 31, 2010. The phantom units shown below have been awarded over the last four years, with a portion of the units vesting in February in each of 2011, 2012, 2013 and 2014.

Named Executive Officer	Number of Phantom Units That Have Not Vested (#)	Market Value of Phantom Units That Have Not Vested(1) ($)
Corbin J. Robertson, Jr.	114,000	4,087,560
Dwight L. Dunlap	30,200	1,086,790
Nick Carter	51,000	1,827,300
Wyatt L. Hogan	29,800	1,073,510
Kevin F. Wall	29,000	1,046,950

(1) Based on a unit price of $33.20, the closing price for the common units on December 31, 2010. The value also includes the value of the accrued distribution equivalent rights as of December 31, 2010.

Phantom Units Vested in 2010

The table below shows the phantom units that vested with respect to each named executive officer in 2010, along with the value realized by each individual.

Named Executive Officer	Number of Phantom Units That Vested (#)	Value Realized on Vesting ($)
Corbin J. Robertson, Jr.	20,000	481,200
Dwight L. Dunlap	7,000	168,420
Nick Carter	10,000	240,600
Wyatt L. Hogan	5,800	139,548
Kevin F. Wall	5,200	125,112

Potential Payments upon Termination or Change in Control

None of our executive officers have entered into employment agreements with Natural Resource Partners or its affiliates. Consequently, there are no severance benefits payable to any executive officer upon the termination of their employment. The annual base salaries, bonuses and other compensation are all determined by the CNG Committee in consultation with Mr. Robertson, Mr. Carter and the full board of directors. Upon the occurrence of a change in control of NRP, our general partner or GP Natural Resource Partners LLC, the outstanding phantom unit awards held by each of our executive officers would immediately vest. The table below indicates the impact of a change in control on the outstanding equity-based awards at December 31, 2010, based on the 20-day average of the common units of $31.63 on December 31, 2010 and includes amounts for accrued distribution equivalent rights.

Named Executive Officer	Number of Phantom Units That Have Not Vested (#)	Potential Post-Employment Payments Required Upon Change in Control ($)	Potential Cash Payments Required Upon Change in Control ($)
Corbin J. Robertson, Jr.	114,000	—	3,908,580
Dwight L. Dunlap	30,200	—	1,039,376
Nick Carter	51,000	—	1,747,230
Wyatt L. Hogan	29,800	—	1,026,724
Kevin F. Wall	29,000	—	1,001,420

Director's Compensation for the Year Ended December 31, 2010

The table below shows the directors' compensation for the year ended December 31, 2010. As with our named executive officers, we do not grant any options or restricted units to our directors.

Name	Fees Earned or Paid in Cash ($)	Phantom Unit Awards(1)(2) ($)	Total ($)
Robert Blakely	90,000	72,180	162,180
David Carmichael	85,000	72,180	157,180
J. Matthew Fifield	50,000	72,180	122,180
Robert Karn III	85,000	72,180	157,180
S. Reed Morian	50,000	72,180	122,180
Stephen Smith	65,000	72,180	137,180
W. W. Scott, Jr.	50,000	72,180	122,180
Leo A. Vecellio, Jr.	65,000	72,180	137,180

(1) Amounts represent the grant date fair value of unit awards determined in accordance with Financial Accounting Standard Board stock compensation authoritative guidance.

(2) As of December 31, 2010, each director held 12,000 phantom units that vest in annual increments of 3,000 units in each of 2011, 2011, 2013 and 2014.

In 2010, the annual retainer for the directors was $50,000, and the directors did not receive any additional fees for attending meetings. Each chairman of a committee received an annual fee of $10,000 for serving as chairman, and each committee member received $5,000 for serving on a committee.

2011 Long-Term Incentive Awards

In February 2011, the CNG Committee awarded 33,000 phantom units to Mr. Robertson, 15,000 phantom units to Mr. Carter, and 9,000 phantom units to each of Messrs. Dunlap, Hogan and Wall. The phantom units included tandem distribution equivalent rights, pursuant to which the units will accrue the quarterly distributions paid by NRP on its common units. NRP will pay the amounts accrued under the distribution equivalent rights upon the vesting of the phantom units in February 2015. The CNG Committee also recommended, and the Board of Directors approved, an award of 3,000 phantom units, including tandem distribution equivalent rights, to each of the members of the Board of Directors. The awards to the directors will also vest in February 2015.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended December 31, 2010, Messrs. Carmichael, Karn, Blakely and Vecellio served on the CNG Committee. None of Messrs. Carmichael, Karn, Blakely or Vecellio has ever been an officer or employee of NRP or GP Natural Resource Partners LLC. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has any executive officer serving as a member of our Board of Directors or CNG Committee.

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

The following table sets forth, as of February 28, 2011 the amount and percentage of our common units beneficially held by (1) each person known to us to beneficially own 5% or more of any class of our units, (2) by each of the directors and executive officers and (3) by all directors and executive officers as a group. Unless otherwise noted, each of the named persons and members of the group has sole voting and investment power with respect to the units shown.

Name of Beneficial Owner	Common Units	Percentage of Common Units(1)
Corbin J. Robertson, Jr.(2)	22,684,901	21.4%
Western Pocahontas Properties(3)(4)	17,279,860	16.3%
Christopher Cline(5)	21,017,441	19.8%
Adena Minerals LLC(6)	20,976,841	19.8%
Nick Carter(7)	14,210	*
Dwight L. Dunlap	16,945	*
Kevin F. Wall(8)	2,000	*
Wyatt L. Hogan(9)	1,500	*
Dennis F. Coker	400	*
Kevin J. Craig	3,600	*
Kenneth Hudson	4,000	*
Kathy H. Roberts	13,000	*
Robert T. Blakely	—	—
David M. Carmichael	10,000	*
J. Matthew Fifield	—	—
Robert B. Karn III(10)	5,634	*
S. Reed Morian(11)	5,052,345	4.8%
W. W. Scott, Jr.(12)	339,239	*
Stephen P. Smith	3,552	*
Leo A. Vecellio, Jr.	20,000	*
Directors and Officers as a Group	28,171,326	26.6%

* Less than one percent.

(1) Percentages based upon 106,027,836 common units issued and outstanding. Unless otherwise noted, beneficial ownership is less than 1%.

(2) Mr. Robertson may be deemed to beneficially own the 17,279,860 common units owned by Western Pocahontas Properties Limited Partnership, 5,102,385 common units held by Western Bridgeport, Inc, 101,770 common units held by Western Pocahontas Corporation and 52 common units held by QMP Inc. Also included are 31,540 common units held by Barbara Robertson, Mr. Robertson's spouse. Mr. Robertson's address is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

(3) These units may be deemed to be beneficially owned by Mr. Robertson. Western Pocahontas has pledged 6,711,944 units as collateral on its long term debt.

(4) The address of Western Pocahontas Properties Limited Partnership is 601 Jefferson Street, Suite 3600, Houston, Texas 77002.

(5) Mr. Cline may be deemed to beneficially own the 20,976,841 common units owned by Adena Minerals, LLC. These units have all been pledged to banks as collateral for loans. Mr. Cline's address is 3801 PGA Boulevard, Suite 903, Palm Beach Gardens, FL 33410.

(6) The address of Adena Minerals LLC is 3801 PGA Boulevard, Suite 903, Palm Beach Gardens, FL 33410. These units have all been pledged to banks as collateral for loans.

(7) Includes 210 common units held by Mr. Carter's spouse, the remaining 14,000 of these units are pledged as collateral for a personal line of credit.

(8) Includes 500 common units held by Mr. Wall's daughter. Mr. Wall disclaims beneficial ownership of these securities.

(9) Of these common units, 500 common units are owned by the Anna Margaret Hogan 2002 Trust, 500 common units are owned by the Alice Elizabeth Hogan 2002 Trust, and 500 common units are held by the Ellen Catlett Hogan 2005 Trust. Mr. Hogan is a trustee of each of these trusts.

(10) Includes 317 units held by the Payton Grace Portnoy Irrevocable Trust and 317 units held by the Blake Kristopher Portnoy Irrevocable Trust. Mr. Karn is the trustee of each of these trusts for his grandchildren, but disclaims beneficial ownership of these securities.

(11) Mr. Morian may be deemed to beneficially own 2,811,854 common units owned by Shadder Investments and 341,376 common units held by Mocol Properties.

(12) Mr. Scott may be deemed to beneficially own 30,766 common units held by Scott Riverbend Farms and 8,000 units held by his spouse, Kate Scott.

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

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.

Omnibus Agreement

Non-competition Provisions

As part of the omnibus agreement entered into concurrently with the closing of our initial public offering, the WPP Group and any entity controlled by Corbin J. Robertson, Jr., which we refer to in this section as the GP affiliates, each agreed that neither they nor their affiliates will, directly or indirectly, engage or invest in entities that engage in the following activities (each, a "restricted business") in the specific circumstances described below:

- the entering into or holding of leases with a party other than an affiliate of the GP affiliate for any GP affiliate-owned fee coal reserves within the United States; and

- the entering into or holding of subleases with a party other than an affiliate of the GP affiliate for coal reserves within the United States controlled by a paid-up lease owned by any GP affiliate or its affiliate.

"Affiliate" means, with respect to any GP affiliate or, any other entity in which such GP affiliate owns, through one or more intermediaries, 50% or more of the then outstanding voting securities or other ownership interests of such entity. Except as described below, the WPP Group and their respective controlled affiliates will not be prohibited from engaging in activities in which they compete directly with us.

A GP affiliate may, directly or indirectly, engage in a restricted business if:

- the GP affiliate was engaged in the restricted business at the closing of the offering; provided that if the fair market value of the asset or group of related assets of the restricted business subsequently exceeds $10 million, the GP affiliate must offer the restricted business to us under the offer procedures described below.
- the asset or group of related assets of the restricted business have a fair market value of $10 million or less; provided that if the fair market value of the assets of the restricted business subsequently exceeds $10 million, the GP affiliate must offer the restricted business to us under the offer procedures described below.
- the asset or group of related assets of the restricted business have a fair market value of more than $10 million and the general partner (with the approval of the conflicts committee) has elected not to cause us to purchase these assets under the procedures described below.
- its ownership in the restricted business consists solely of a noncontrolling equity interest.

For purposes of this paragraph, "fair market value" means the fair market value as determined in good faith by the relevant GP affiliate.

The total fair market value in the good faith opinion of the WPP Group of all restricted businesses engaged in by the WPP Group, other than those engaged in by the WPP Group at closing of our initial public offering, may not exceed $75 million. For purposes of this restriction, the fair market value of any entity engaging in a restricted business purchased by the WPP Group will be determined based on the fair market value of the entity as a whole, without regard for any lesser ownership interest to be acquired.

If the WPP Group desires to acquire a restricted business or an entity that engages in a restricted business with a fair market value in excess of $10 million and the restricted business constitutes greater than 50% of the value of the business to be acquired, then the WPP Group must first offer us the opportunity to purchase the restricted business. If the WPP Group desires to acquire a restricted business or an entity that engages in a restricted business with a value in excess of $10 million and the restricted business constitutes 50% or less of the value of the business to be acquired, then the GP affiliate may purchase the restricted business first and then offer us the opportunity to purchase the restricted business within six months of acquisition. For purposes of this paragraph, "restricted business" excludes a general partner interest or managing member interest, which is addressed in a separate restriction summarized below. For purposes of this paragraph only, "fair market value" means the fair market value as determined in good faith by the relevant GP affiliate.

If we want to purchase the restricted business and the GP affiliate and the general partner, with the approval of the conflicts committee, agree on the fair market value and other terms of the offer within 60 days after the general partner receives the offer from the GP affiliate, we will purchase the restricted business as soon as commercially practicable. If the GP affiliate and the general partner, with the approval of the conflicts committee, are unable to agree in good faith on the fair market value and other terms of the offer within 60 days after the general partner receives the offer, then the GP affiliate may sell the restricted business to a third party within two years for no less than the purchase price and on terms no less favorable to the GP affiliate than last offered by us. During this two-year period, the GP affiliate may operate the restricted business in competition with us, subject to the restriction on total fair market value of restricted businesses owned in the case of the WPP Group.

If, at the end of the two year period, the restricted business has not been sold to a third party and the restricted business retains a value, in the good faith opinion of the relevant GP affiliate, in excess of $10 million, then the GP affiliate must reoffer the restricted business to the general partner. If the GP affiliate and the general partner, with the approval of the conflicts committee, agree on the fair market value and other terms of the offer within 60 days after the general partner receives the second offer from the GP affiliate, we will purchase the restricted business as soon as commercially practicable. If the GP Affiliate and the general partner, with the concurrence of the conflicts committee, again fail to agree after negotiation in good faith on the fair market value of the restricted business, then the GP affiliate will be under no further obligation to us with respect to the restricted business, subject to the restriction on total fair market value of restricted businesses owned.

In addition, if during the two-year period described above, a change occurs in the restricted business that, in the good faith opinion of the GP affiliate, affects the fair market value of the restricted business by more than 10 percent and the fair market value of the restricted business remains, in the good faith opinion of the relevant GP affiliate, in excess of $10 million, the GP affiliate will be obligated to reoffer the restricted business to the general partner at the new fair market value, and the offer procedures described above will recommence.

If the restricted business to be acquired is in the form of a general partner interest in a publicly held partnership or a managing member interest in a publicly held limited liability company, the WPP Group may not acquire such restricted business even if we decline to purchase the restricted business. If the restricted business to be acquired is in the form of a general partner interest in a non-publicly held partnership or a managing member of a non-publicly held limited liability company, the WPP Group may acquire such restricted business subject to the restriction on total fair market value of restricted businesses owned and the offer procedures described above.

The omnibus agreement may be amended at any time by the general partner, with the concurrence of the conflicts committee. The respective obligations of the WPP Group under the omnibus agreement terminate when the WPP Group and its affiliates cease to participate in the control of the general partner.

Restricted Business Contribution Agreement

In connection with our partnership with the Cline Group, Christopher Cline, Foresight Reserves LP and Adena (collectively, the "Cline Entities") and NRP have executed a Restricted Business Contribution Agreement. Pursuant to the terms of the Restricted Business Contribution Agreement, the Cline Entities and their affiliates are obligated to offer to NRP any business owned, operated or invested in by the Cline Entities, subject to certain exceptions, that either (a) owns, leases or invests in hard minerals or (b) owns, operates, leases or invests in transportation infrastructure relating to future mine developments by the Cline Entities in Illinois. In addition, we created an area of mutual interest (the "AMI") around certain of the properties that we have acquired from Cline. During the applicable term of the Restricted Business Contribution Agreement, the Cline Entities will be obligated to contribute any coal reserves held or acquired by the Cline Entities or their affiliates within the AMI to us. In connection with the offer of mineral properties by the Cline Entities to NRP, the parties to the Restricted Business Contribution Agreement will negotiate and agree upon an area of mutual interest around such minerals, which will supplement and become a part of the AMI.

We have made several acquisitions from the Cline Group pursuant to the Restricted Business Contribution Agreement. For a summary of recent acquisitions and revenues that we have derived from the Cline relationship, please read Management's Discussion and Analysis of Financial Condition and Results of Operations — Recent Acquisitions and — Transactions with Cline Affiliates in this Form 10-K.

Investor Rights Agreement

NRP and certain affiliates and Adena executed an Investor Rights Agreement pursuant to which Adena was granted certain management rights. Specifically, Adena has the right to name two directors (one of which must be independent) to the board of directors of our managing general partner so long as Adena beneficially owns either 5% of our limited partnership interest or 5% of our general partner's limited partnership interest and so long as certain rights under our managing general partner's LLC Agreement have not been exercised by Adena or Mr. Robertson. Adena nominated J. Matthew Fifield, Managing Director of Adena, and Leo A. Vecellio to serve as the two directors. Mr. Vecellio serves on our CNG Committee. Adena will also have the right, pursuant to the terms of the Investor Rights Agreement, to withhold its consent to the sale or other disposition of any entity or assets contributed by the Cline entities to NRP, and any such sale or disposition will be void without Adena's consent.

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, NRP's Board of Directors 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. The basic tenets of the policy are set forth below.

- NRP's business strategy is focused on the ownership of non-operated royalty producing coal properties in North America and the leasing of these coal reserves. In addition, NRP has extended its business into the ownership and leasing of other non-operated royalty producing extracted hard mineral properties. NRP also has added the transportation, storage and related logistics activities related to coal and other hard minerals to its business strategy. These current and prospective businesses are referred to as the "NRP Businesses."

- NRP's business strategy does not, and is not expected to, include oil and gas exploration or development (except for non-operated royalty interests in coal bed methane production ancillary to its coal business), investments which do not generate "qualifying income" for a publicly traded partnership under U.S. tax regulations, investments outside of North America and other "midstream" or refining businesses which do not involve coal or other hard extracted minerals, including the gathering, processing, fractionation, refining, storage or transportation of oil, natural gas or natural gas liquids. NRP's business strategy also does not, and is not expected to include, coal mining or mining for other hard minerals. The businesses and investments described in this paragraph are referred to as the "Non-NRP Businesses".

- For so long as Corbin Robertson, Jr. remains both an affiliate of Quintana Capital and an executive officer or director of NRP or an affiliate of its general partner, before making an investment in an NRP Business, Quintana Capital will first offer such opportunity in its entirety to NRP. NRP may elect to pursue such investment wholly for its own account, to pursue the opportunity jointly with Quintana Capital or not to pursue such opportunity. If NRP elects not to pursue an NRP Business investment opportunity, Quintana Capital may pursue the investment for its own account. Decisions in respect of such opportunities will be made for NRP by the Conflicts Committee of the Board of Directors of the general partner; provided, however, that decisions in respect of potential investments of $20 million or less may be made by an executive officer of the general partner to whom such authority is delegated by the Conflicts Committee. NRP will undertake to advise Quintana Capital of its decision regarding a potential investment opportunity within 10 business days of the identification of such opportunity to either the Conflicts Committee or such designated officer, as applicable.

- Neither Quintana Capital nor Mr. Robertson will have any obligation to offer investments relating to Non-NRP Businesses to NRP and that NRP will not have any obligation to refrain from pursuing a Non-NRP Business if there is a change in its business strategy. If such a change in strategy occurs, it is expected that the Conflicts Committee would work together with Quintana Capital to adopt mutually agreed practices and procedures in order to safeguard confidential information relating to potential investments and to address any potential or actual conflicts of interest involving Quintana Capital investments or the activities of Mr. Robertson.

A fund controlled by Quintana Capital owns a 43% membership interest in Taggart Global, including the right to nominate two members of Taggart's 5-person board of directors. NRP currently has 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. NRP will own and lease the plants to Taggart Global, who 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. NRP and Taggart Global have jointly financed and developed four such plants in West Virginia.

A fund controlled by Quintana Capital owns Kopper-Glo, a small coal mining company with operations in Tennessee. Kopper-Glo is an NRP lessee that paid NRP $1.5 million and $1.6 million in coal royalties in 2010 and 2009, respectively.

Office Building in Huntington, West Virginia

On January 1, 2009, we began leasing substantially all of two floors of an office building in Huntington, West Virginia from Western Pocahontas Properties Limited Partnership. The terms of the lease, including $0.5 million per year in lease payments, were approved by our conflicts committee.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including the WPP Group, the Cline Group, and their affiliates) on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of GP Natural Resource Partners LLC have fiduciary duties to manage GP Natural Resource Partners LLC and our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and our partnership or any other partner, on the other, our general partner will resolve that conflict. Our general partner may, but is not required to, seek the approval of the conflicts committee of the board of directors of our general partner of such resolution. The partnership agreement contains provisions that allow our general partner to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. In effect, these provisions limit our general partner's fiduciary duties to our unitholders. Delaware case law has not definitively established the limits on the ability of a partnership agreement to restrict such fiduciary duties. The partnership agreement also restricts the remedies available to unitholders for actions taken by our general partner that might, without those limitations, constitute breaches of fiduciary duty.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is considered to be fair and reasonable to us. Any resolution is considered to be fair and reasonable to us if that resolution is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval and our general partner may adopt a resolution or course of action that has not received approval;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair to us, taking into account the totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In resolving a conflict, our general partner, including its conflicts committee, may, unless the resolution is specifically provided for in the partnership agreement, consider:

- the relative interests of any party to such conflict and the benefits and burdens relating to such interest;
- any customary or accepted industry practices or historical dealings with a particular person or entity;
- generally accepted accounting practices or principles; and
- such additional factors it determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

Conflicts of interest could arise in the situations described below, among others.

Actions taken by our general partner may affect the amount of cash available for distribution to unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;
- the issuance of additional units; and
- the creation, reduction or increase of reserves in any quarter.

In addition, borrowings by us and our affiliates do not constitute a breach of any duty owed by our general partner to the unitholders, including borrowings that have the purpose or effect of enabling our general partner to receive distributions on the incentive distribution rights.

For example, in the event we have not generated sufficient cash from our operations to pay the quarterly distribution on our common units, our partnership agreement permits us to borrow funds which may enable us to make this distribution on all outstanding units.

The partnership agreement provides that we and our subsidiaries may borrow funds from our general partner and its affiliates. Our general partner and its affiliates may not borrow funds from us or our subsidiaries.

We do not have any officers or employees and rely solely on officers and employees of GP Natural Resource Partners LLC and its affiliates.

We do not have any officers or employees and rely solely on officers and employees of GP Natural Resource Partners LLC and its affiliates. Affiliates of GP Natural Resource Partners LLC conduct businesses and activities of their own in which we have no economic interest. If these separate activities are significantly greater than our activities, there could be material competition for the time and effort of the officers and employees who provide services to our general partner. The officers of GP Natural Resource Partners LLC are not required to work full time on our affairs. These officers devote significant time to the affairs of the WPP Group or its affiliates and are compensated by these affiliates for the services rendered to them.

We reimburse our general partner and its affiliates for expenses.

We reimburse our general partner and its affiliates for costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. The partnership agreement provides that our general partner determines the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the other party has recourse only to our assets, and not against our general partner or its assets. The partnership agreement provides that any action taken by our general partner to limit its liability or our liability is not a breach of our general partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability.

Common unitholders have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us on the one hand, and our general partner and its affiliates, on the other, do not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, are not the result of arm's-length negotiations.

The partnership agreement allows our general partner to pay itself or its affiliates for any services rendered to us, provided these services are rendered on terms that are fair and reasonable. Our general partner may also enter into additional contractual arrangements with any of its affiliates on our behalf. Neither the partnership agreement nor any of the other agreements, contracts and arrangements between us, on the one hand, and our general partner and its affiliates, on the other, are the result of arm's-length negotiations.

All of these transactions entered into after our initial public offering are on terms that are fair and reasonable to us.

Our general partner and its affiliates have no obligation to permit us to use any facilities or assets of our general partner and its affiliates, except as may be provided in contracts entered into specifically dealing with that use. There is no obligation of our general partner or its affiliates to enter into any contracts of this kind.

We may not choose to retain separate counsel for ourselves or for the holders of common units.

The attorneys, independent auditors and others who have performed services for us in the past were retained by our general partner, its affiliates and us and have continued to be retained by our general partner, its affiliates and us. Attorneys, independent auditors and others who perform services for us are selected by our general partner or the conflicts committee and may also perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the holders of common units in the event of a conflict of interest arising between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict. We do not intend to do so in most cases. Delaware case law has not definitively established the limits on the ability of a partnership agreement to restrict such fiduciary duties.

Our general partner's affiliates may compete with us.

The partnership agreement provides that our general partner is restricted from engaging in any business activities other than those incidental to its ownership of interests in us. Except as provided in our partnership agreement, the Omnibus Agreement and the Restricted Business Contribution Agreement, affiliates of our general partner will not be prohibited from engaging in activities in which they compete directly with us.

Director Independence

For a discussion of the independence of the members of the board of directors of our managing general partner under applicable standards, please read "Item 10. Directors and Executive Officers of the Managing General Partner and Corporate Governance — Corporate Governance — Independence of Directors," which is incorporated by reference into this Item 13.

Review, Approval or Ratification of Transactions with Related Persons

If a conflict or potential conflict of interest arises between our general partner and its affiliates (including the WPP Group, the Cline Group, and their affiliates) on the one hand, and our partnership and our limited partners, on the other hand, the resolution of any such conflict or potential conflict is addressed as described under "— Conflicts of Interest."

Pursuant to our Code of Business Conduct and Ethics, conflicts of interest are prohibited as a matter of policy, except under guidelines approved by the Board of Directors and as provided in the Omnibus Agreement, the Restricted Business Contribution Agreement, and our partnership agreement. For the year ended December 31, 2010, there were no transactions where such guidelines were not followed.

Item 14. *Principal Accounting Fees and Services*

The Audit Committee of the Board of Directors of GP Natural Resource Partners LLC recommended and we engaged Ernst & Young LLP to audit our accounts and assist with tax work for fiscal 2010 and 2009. Fees (including out-of-pocket costs) incurred from Ernst & Young LLP for services for fiscal years 2010 and 2009 totaled $1.0 million and $0.9 million, respectively. All of our audit, audit-related fees and tax services have been approved by the Audit Committee of our Board of Directors. The following table presents fees for professional services rendered by Ernst &Young LLP:

	2010	2009
Audit Fees(1)	$527,674	$394,000
Audit-Related Fees	—	—
Tax Fees(2)	521,377	504,222
All Other Fees	—	—

(1) Audit fees include fees associated with the annual audit of our consolidated financial statements and reviews of our quarterly financial statement for inclusion in our Form 10-Q and comfort letters; consents; assistance with and review of documents filed with the SEC.

(2) Tax fees include fees principally incurred for assistance with tax planning, compliance, tax return preparation and filing of Schedules K-1.

Audit and Non-Audit Services Pre-Approval Policy

I. Statement of Principles

Under the Sarbanes-Oxley Act of 2002 (the "Act"), the Audit Committee of the Board of Directors is responsible for the appointment, compensation and oversight of the work of the independent auditor. As part of this responsibility, the Audit Committee is required to pre-approve the audit and non-audit services performed by the independent auditor in order to assure that they do not impair the auditor's independence from the Partnership. To implement these provisions of the Act, the Securities and Exchange Commission (the "SEC") has issued rules specifying the types of services that an independent auditor may not provide to its audit client, as well as the audit committee's administration of the engagement of the independent auditor. Accordingly, the Audit Committee has adopted, and the Board of Directors has ratified, this Audit and Non-Audit Services Pre-Approval Policy (the "Policy"), which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent auditor may be pre-approved.

The SEC's rules establish two different approaches to pre-approving services, which the SEC considers to be equally valid. Proposed services may either be pre-approved without consideration of specific case-by-case services by the Audit Committee ("general pre-approval") or require the specific pre-approval of the Audit Committee ("specific pre-approval"). The Audit Committee believes that the combination of these two approaches in this Policy will result in an effective and efficient procedure to pre-approve services performed by the independent auditor. As set forth in this Policy, unless a type of service has received general pre-approval, it will require specific pre-approval by the Audit Committee if it is to be provided by the independent auditor. Any proposed services exceeding pre-approved cost levels or budgeted amounts will also require specific pre-approval by the Audit Committee.

For both types of pre-approval, the Audit Committee will consider whether such services are consistent with the SEC's rules on auditor independence. The Audit Committee will also consider whether the independent auditor is best positioned to provide the most effective and efficient service for reasons such as its familiarity with our business, employees, culture, accounting systems, risk profile and other factors, and whether the service might enhance the Partnership's ability to manage or control risk or improve audit quality. All such factors will be considered as a whole, and no one factor will necessarily be determinative.

The Audit Committee is also mindful of the relationship between fees for audit and non-audit services in deciding whether to pre-approve any such services and may determine, for each fiscal year, the appropriate ratio between the total amount of fees for audit, audit-related and tax services.

The appendices to this Policy describe the audit, audit-related and tax services that have the general pre-approval of the Audit Committee. The term of any general pre-approval is 12 months from the date of pre-approval, unless the Audit Committee considers a different period and states otherwise. The Audit Committee will annually review and pre-approve the services that may be provided by the independent auditor without obtaining specific pre-approval from the Audit Committee. The Audit Committee will add or subtract to the list of general pre-approved services from time to time, based on subsequent determinations.

The purpose of this Policy is to set forth the procedures by which the Audit Committee intends to fulfill its responsibilities. It does not delegate the Audit Committee's responsibilities to pre-approve services performed by the independent auditor to management.

Ernst & Young LLP, our independent auditor has reviewed this Policy and believes that implementation of the policy will not adversely affect its independence.

II. Delegation

As provided in the Act and the SEC's rules, the Audit Committee has delegated either type of pre-approval authority to Robert B. Karn III, the Chairman of the Audit Committee. Mr. Karn must report, for informational purposes only, any pre-approval decisions to the Audit Committee at its next scheduled meeting.

III. Audit Services

The annual Audit services engagement terms and fees will be subject to the specific pre-approval of the Audit Committee. Audit services include the annual financial statement audit (including required quarterly reviews), subsidiary audits, equity investment audits and other procedures required to be performed by the independent auditor to be able to form an opinion on the Partnership's consolidated financial statements. These other procedures include information systems and procedural reviews and testing performed in order to understand and place reliance on the systems of internal control, and consultations relating to the audit or quarterly review. Audit services also include the attestation engagement for the independent auditor's report on management's report on internal controls for financial reporting. The Audit Committee monitors the audit services engagement as necessary, but not less than on a quarterly basis, and approves, if necessary, any changes in terms, conditions and fees resulting from changes in audit scope, partnership structure or other items.

In addition to the annual audit services engagement approved by the Audit Committee, the Audit Committee may grant general pre-approval to other audit services, which are those services that only the independent auditor reasonably can provide. Other audit services may include statutory audits or financial audits for our subsidiaries or our affiliates and services associated with SEC registration statements, periodic reports and other documents filed with the SEC or other documents issued in connection with securities offerings.

IV. Audit-related Services

Audit-related services are assurance and related services that are reasonably related to the performance of the audit or review of the Partnership's financial statements or that are traditionally performed by the independent auditor. Because the Audit Committee believes that the provision of audit-related services does not impair the independence of the auditor and is consistent with the SEC's rules on auditor independence, the Audit Committee may grant general pre-approval to audit-related services. Audit-related services include, among others, due diligence services pertaining to potential business acquisitions/dispositions; accounting consultations related to accounting, financial reporting or disclosure matters not classified as "Audit Services";

assistance with understanding and implementing new accounting and financial reporting guidance from rulemaking authorities; financial audits of employee benefit plans; agreed-upon or expanded audit procedures related to accounting and/or billing records required to respond to or comply with financial, accounting or regulatory reporting matters; and assistance with internal control reporting requirements.

V. Tax Services

The Audit Committee believes that the independent auditor can provide tax services to the Partnership such as tax compliance, tax planning and tax advice without impairing the auditor's independence, and the SEC has stated that the independent auditor may provide such services. Hence, the Audit Committee believes it may grant general pre-approval to those tax services that have historically been provided by the auditor, that the Audit Committee has reviewed and believes would not impair the independence of the auditor and that are consistent with the SEC's rules on auditor independence. The Audit Committee will not permit the retention of the independent auditor in connection with a transaction initially recommended by the independent auditor, the sole business purpose of which may be tax avoidance and the tax treatment of which may not be supported in the Internal Revenue Code and related regulations. The Audit Committee will consult with the Chief Financial Officer or outside counsel to determine that the tax planning and reporting positions are consistent with this Policy.

VI. Pre-Approval Fee Levels or Budgeted Amounts

Pre-approval fee levels or budgeted amounts for all services to be provided by the independent auditor will be established annually by the Audit Committee. Any proposed services exceeding these levels or amounts will require specific pre-approval by the Audit Committee. The Audit Committee is mindful of the overall relationship of fees for audit and non-audit services in determining whether to pre-approve any such services. For each fiscal year, the Audit Committee may determine the appropriate ratio between the total amount of fees for audit, audit-related and tax services.

VII. Procedures

All requests or applications for services to be provided by the independent auditor that do not require specific approval by the Audit Committee will be submitted to the Chief Financial Officer and must include a detailed description of the services to be rendered. The Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the Audit Committee. The Audit Committee will be informed on a timely basis of any such services rendered by the independent auditor.

Requests or applications to provide services that require specific approval by the Audit Committee will be submitted to the Audit Committee by both the independent auditor and the Chief Financial Officer, and must include a joint statement as to whether, in their view, the request or application is consistent with the SEC's rules on auditor independence.

PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) and (2) Financial Statements and Schedules

Please See Item 8, "Financial Statements and Supplementary Data"

(a)(3) Exhibits

Exhibit Number		Description
2.1	—	Contribution Agreement dated December 14, 2006 by and among Foresight Reserves LP, Adena Minerals, LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on December 15, 2006).
2.2	—	Contribution Agreement dated December 19, 2006 by and among Dingess-Rum Properties, Inc., Natural Resource Partners L.P. and WPP LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on December 20, 2006).
2.3	—	Second Contribution Agreement, dated January 4, 2007, by and among Foresight Reserves LP, Adena Minerals, LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on January 4, 2007).
2.4	—	Amendment No. 1 to Second Contribution Agreement, dated April 18, 2007, by and among Natural Resource Partners L.P., NRP (GP) LP, NRP (Operating) LLC, Foresight Reserves LP and Adena Minerals, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on April 19, 2007).
2.5	—	Purchase and Sale Agreement, dated April 2, 2007, by and among Natural Resource Partners L.P., WPP LLC and Western Pocahontas Properties Limited Partnership (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on April 3, 2007).
3.1	—	Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P., dated as of September 20, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on September 21, 2010).
3.2	—	Fourth Amended and Restated Agreement of Limited Partnership of NRP (GP) LP, dated as of September 20, 2010 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed on September 21, 2010).
3.3	—	Fourth Amended and Restated Limited Liability Company Agreement of GP Natural Resource Partners LLC, dated as of January 4, 2007 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on January 4, 2007).
3.4	—	Amended and Restated Limited Liability Company Agreement of NRP (Operating) LLC, dated as of October 17, 2002 (incorporated by reference to Exhibit 3.4 of the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).
4.1	—	Note Purchase Agreement dated as of June 19, 2003 among NRP (Operating) LLC and the Purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed June 23, 2003).
4.2	—	First Supplement to Note Purchase Agreements, dated as of July 19, 2005 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on July 20, 2005).
4.3	—	Second Supplement to Note Purchase Agreements, dated as of March 28, 2007 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on March 29, 2007).

Exhibit Number		Description
4.4	—	Third Supplement to Note Purchase Agreements, dated as of March 25, 2009 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on March 26, 2009).
4.5	—	First Amendment, dated as of July 19, 2005, to Note Purchase Agreements dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on July 20, 2005).
4.6	—	Second Amendment, dated as of March 28, 2007, to Note Purchase Agreements dated as of June 19, 2003 among NRP (Operating) LLC and the purchasers signatory thereto (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on March 29, 2007).
4.7	—	Subsidiary Guarantee of Senior Notes of NRP (Operating) LLC, dated June 19, 2003 (incorporated by reference to Exhibit 4.5 to the Current Report on Form 8-K filed June 23, 2003).
4.8	—	Form of Series A Note (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed June 23, 2003).
4.9	—	Form of Series B Note (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed June 23, 2003).
4.10	—	Form of Series C Note (incorporated by reference to Exhibit 4.4 to the Current Report on Form 8-K filed June 23, 2003).
4.11	—	Form of Series D Note (incorporated by reference to Exhibit 4.12 to the Annual Report on Form 10-K filed February 28, 2007).
4.12	—	Form of Series E Note (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed March 29, 2007).
4.13	—	Form of Series F Note (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q filed May 7, 2009).
4.14	—	Form of Series G Note (incorporated by reference to Exhibit 4.3 to the Quarterly Report on Form 10-Q filed May 7, 2009).
10.1	—	Amended and Restated Credit Agreement, dated as of March 28, 2007, by and among NRP (Operating) LLC, as Borrower, Citibank, N.A., as Administrative Agent, and the other lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 29, 2007).
10.2	—	First Amendment to Amended and Restated Credit Agreement, dated May 11, 2010, by and among NRP (Operating) LLC and the banks and other financial institutions listed on the signature pages thereto, including Citibank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q filed August 6, 2010).
10.2	—	Contribution Agreement, dated as of September 20, 2010, by and among Natural Resource Partners L.P., NRP (GP) LP, Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation and NRP Investment L.P. (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on September 21, 2010).
10.3	—	Natural Resource Partners Second Amended and Restated Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 17, 2008).
10.4	—	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K for the year ended December 31, 2007, File No. 007-31465).
10.5	—	Natural Resource Partners Annual Incentive Plan (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-31465).

Exhibit Number		Description
10.6	—	First Amended and Restated Omnibus Agreement, dated as of April 22, 2009, by and among Western Pocahontas Properties Limited Partnership, Great Northern Properties Limited Partnership, New Gauley Coal Corporation, Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed May 7, 2009)..
10.7	—	Restricted Business Contribution Agreement, dated January 4, 2007, by and among Christopher Cline, Foresight Reserves LP, Adena Minerals, LLC, GP Natural Resource Partners LLC, NRP (GP) LP, Natural Resource Partners L.P. and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 4, 2007).
10.8	—	Investor Rights Agreement, dated January 4, 2007, by and among NRP (GP) LP, GP Natural Resource Partners LLC, Robertson Coal Management and Adena Minerals, LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on January 4, 2007).
10.9	—	Purchase and Sale Agreement, dated January 27, 2009, by and among WPP LLC, Hod LLC and Macoupin Energy, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on January 27, 2009).
10.10	—	Purchase and Sale Agreement, dated September 10, 2009, by and among WPP LLC and Colt, LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K filed on September 11, 2009).
10.11	—	Amendment No. 1 to Purchase and Sale Agreement, dated as of July 29, 2010, by and between WPP LLC and Colt, LLC (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q filed August 6, 2010).
10.11	—	Amendment No. 2 to Purchase and Sale Agreement, dated as of October 4, 2010, by and between WPP LLC and Colt, LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed October 5, 2010).
10.12	—	Waiver Agreement, dated November 12, 2009, by and among Natural Resource Partners L.P., Great Northern Properties Limited Partnership, Western Pocahontas Properties Limited Partnership, New Gauley Coal Corporation, Robertson Coal Management LLC, GP Natural Resource Partners LLC, NRP (GP) LP, and NRP (Operating) LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed on November 13, 2009).
21.1*	—	List of subsidiaries of Natural Resource Partners L.P.
23.1*	—	Consent of Ernst & Young LLP.
31.1*	—	Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley.
31.2*	—	Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley.
32.1*	—	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350.
32.2*	—	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350.
99.1	—	Description of certain provisions of the Fourth Amended and Restated Agreement of Limited Partnership of Natural Resource Partners L.P. (incorporated by reference to Exhibit 99.1 to Current Report on Form 8-K filed on September 21, 2010).
101*	—	The following financial information from the annual report on Form 10-K of Natural Resource Partners L.P. for the year ended December 31, 2010, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Income, (iii) Consolidated Statements of Cash Flows, and (iv) Notes to Consolidated Financial Statements, tagged as blocks of text.

* Submitted herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

NATURAL RESOURCE PARTNERS L.P.
By: NRP (GP) LP, its general partner
By: GP NATURAL RESOURCE PARTNERS LLC, its general partner

Date: February 28, 2011

By: /s/ CORBIN J. ROBERTSON, JR.,
Corbin J. Robertson, Jr.,
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)

Date: February 28, 2011

By: /s/ DWIGHT L. DUNLAP
Dwight L. Dunlap,
Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 28, 2011

By: /s/ KENNETH HUDSON
Kenneth Hudson
Controller
(Principal Accounting Officer)

Date: February 28, 2011

By: /s/ ROBERT T. BLAKELY
Robert T. Blakely
Director

Date: February 28, 2011

By: /s/ DAVID M. CARMICHAEL
David M. Carmichael
Director

Date: February 28, 2011

By: /s/ J. MATTHEW FIFIELD

J. Matthew Fifield
Director

Date: February 28, 2011

By: /s/ ROBERT B. KARN III

Robert B. Karn III
Director

Date: February 28, 2011

By: /s/ S. REED MORIAN

S. Reed Morian
Director

Date: February 28, 2011

By: /s/ W.W. SCOTT, JR.

W.W. Scott, Jr.
Director

Date: February 28, 2011

By: /s/ STEPHEN P. SMITH

Stephen P. Smith
Director

Date: February 28, 2011

By: /s/ LEO A. VECELLIO, JR.

Leo A. Vecellio, Jr.
Director

Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

I, Corbin J. Robertson, Jr., certify that:

1) I have reviewed this report on Form 10-K of Natural Resource Partners L.P.

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5) The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions);

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ Corbin J. Robertson, Jr.

Corbin J. Robertson, Jr.
Chief Executive Officer

Date: February 28, 2011

Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

I, Dwight L. Dunlap, certify that:

1) I have reviewed this report on Form 10-K of Natural Resource Partners L.P.

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5) The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions);

a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ Dwight L. Dunlap

Dwight L. Dunlap
Chief Financial Officer and Treasurer

Date: February 28, 2011

Exhibit 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF GP NATURAL RESOURCE PARTNERS LLC
PURSUANT TO 18 U.S.C. § 1350

In connection with the accompanying report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Corbin J. Robertson, Jr., Chief Executive Officer and Chairman of the Board of GP Natural Resource Partners LLC, the general partner of the general partner of Natural Resource Partners L.P. (the "Company"), hereby certify, to my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Corbin J. Robertson, Jr.

Name: Corbin J. Robertson, Jr.

Date: February 28, 2011

Exhibit 32.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF GP NATURAL RESOURCE PARTNERS LLC
PURSUANT TO 18 U.S.C. § 1350**

In connection with the accompanying report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Dwight L. Dunlap, Chief Financial Officer and Treasurer of GP Natural Resource Partners LLC, the general partner of the general partner of Natural Resource Partners L.P. (the "Company"), hereby certify, to my knowledge, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Dwight L. Dunlap

Name: Dwight L. Dunlap

Date: February 28, 2011

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Shareholder Information

Corporate Headquarters
601 Jefferson, Suite 3600
Houston, TX 77002
(713) 751-7507

Operations Headquarters
5260 Irwin Road
Huntington, WV 25705
(304) 522-5757

Investor Relations
Kathy Roberts
601 Jefferson Street,
Suite 3600
Houston, TX 77002
(713) 751-7555
email: kroberts@nrplp.com

Stock Exchange
Our units are listed on the New York Stock Exchange under the symbol NRP.

Independent Auditors
Ernst & Young LLP
5 Houston Center
1401 McKinney, Suite 1200
Houston, TX 77001-2007

Transfer Agent & Registrar
American Stock Transfer and Trust Company
59 Maiden Lane
Plaza Level
New York, NY 10038
Website:
www.amstock.com
Email: info@amstock.com
(800) 937-5449

Website
www.nrplp.com
Information regarding Natural Resource Partners L.P. is located on the partnership's website. On the site are operational and financial information as well as all SEC filings and our corporate governance documents, including our Code of Business Conduct and Ethics, our Corporate Governance Guidelines and all Board of Directors' Committee Charters. Requests for additional copies of the annual report or other data may be made through the website or by contacting Investor Relations free of charge.

Contact NRP Board
We have established procedures for contacting the non-management members of the NRP Board of Directors. To communicate any concerns or issues to the Board of Directors, please direct any correspondence to:

Chairman of the CNG Committee
NRP Board of Directors
601 Jefferson, Suite 3600
Houston, TX 77002

Forward-Looking Statements
Some statements included in this annual report 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, acquisitions and dispositions, expected commencement dates of coal or aggregate mining, projected quantities of future production by our lessees producing coal or aggregates from our reserves, projected royalties associated with our coal infrastructure, 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 "Risks Related to Our Business" in the enclosed Form 10-K for important factors that could cause our actual results of operations or our actual financial condition to differ.

Natural Resource
Partners L.P.

601 Jefferson Street
Suite 3600
Houston, TX 77002

www.nrplp.com