United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-Q

X QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2002.

OR

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

For the transition period from _______________ to _______________.

Commission File Number 001-31303

Black Hills Corporation

Incorporated in South Dakota IRS Identification Number 46-0458824

625 Ninth Street
Rapid City, South Dakota 57701

Registrant's telephone number (605)-721-1700

Former name, former address, and former fiscal year if changed since last report

NONE

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X No ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the last practicable date.

Class	Outstanding at July 31, 2002
Common stock, $1.00 par value	26,858,241 shares

BLACK HILLS CORPORATION

I N D E X

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(unaudited)

	Three Months June 30 2002	Three Months June 30 2001	Six Months June 30 2002	Six Months June 30 2001	Twelve Months June 30 2002	Twelve Months June 30 2001
	(in thousands, except per share amounts)					
Operating revenues	$ 394,309	$ 404,401	$ 686,374	$ 952,081	$ 1,233,742	$ 1,972,409
Operating expenses:						
Fuel and purchased power	304,382	285,275	514,797	719,248	905,319	1,567,944
Operations and maintenance	15,386	15,399	29,798	28,183	63,073	57,303
Administrative and general	18,054	22,398	30,852	45,520	67,932	79,031
Depreciation, depletion and amortization	17,972	12,584	34,336	24,404	63,747	43,630
Taxes, other than income taxes	5,621	5,410	11,906	10,981	24,251	19,000
	361,415	341,066	621,689	828,336	1,124,322	1,766,908
Operating income	32,894	63,335	64,685	123,745	109,420	205,501
Other income (expense):						
Interest expense	(10,530)	(9,318)	(20,151)	(20,201)	(39,732)	(39,729)
Interest income	723	1,008	1,321	1,647	2,478	4,231
Other expense	(498)	(181)	(574)	(311)	(4,652)	(2,875)
Other income	1,853	3,170	3,744	4,745	13,481	11,392
	(8,452)	(5,321)	(15,660)	(14,120)	(28,425)	(26,981)
Income from continuing operations before minority interest, income taxes and change in accounting principle	24,442	58,014	49,025	109,625	80,995	178,520
Minority interest	(1,836)	(2,611)	(4,102)	(4,571)	(3,717)	(15,909)
Income taxes	(7,887)	(20,875)	(15,311)	(39,090)	(26,046)	(61,386)
Income from continuing operations before change in accounting principle	14,719	34,528	29,612	65,964	51,232	101,225
Income (Loss) from discontinued operations, net of taxes	(912)	325	(2,637)	980	(3,124)	1,444
Change in accounting principle, net of taxes	-	-	896	-	896	-
Net income	13,807	34,853	27,871	66,944	49,004	102,669
Preferred stock dividends	(56)	(300)	(112)	(342)	(297)	(420)
Net income available for common stock	$ 13,751	$ 34,553	$ 27,759	$ 66,602	$ 48,707	$ 102,249
Weighted average common shares outstanding:						
Basic	26,804	25,502	26,749	24,245	26,610	23,550
Diluted	27,126	25,978	27,045	24,691	26,930	24,014
Earnings per share:						
Basic-						
Continuing operations	$ 0.55	$ 1.34	$ 1.10	$ 2.71	$ 1.91	$ 4.28
Discontinued operations	(0.04)	0.01	(0.09)	0.04	(0.11)	0.06
Change in accounting principle	-	-	0.03	-	0.03	-
Total	$ 0.51	$ 1.35	$ 1.04	$ 2.75	$ 1.83	$ 4.34
Diluted-						
Continuing operations	$ 0.54	$ 1.33	$ 1.09	$ 2.67	$ 1.90	$ 4.22
Discontinued operations	(0.03)	0.01	(0.09)	0.04	(0.11)	0.06
Change in accounting principle	-	-	0.03	-	0.03	-
Total	$ 0.51	$ 1.34	$ 1.03	$ 2.71	$ 1.82	$ 4.28
Dividends paid per share of common stock	$ 0.29	$ 0.28	$ 0.58	$ 0.56	$ 1.14	$ 1.10

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(unaudited)

	June 30 2002	December 31 2001	June 30 2001
	(in thousands, except share amounts)		
ASSETS			
Current assets:			
Cash and cash equivalents	$ 54,346	$ 29,956	$ 36,040
Securities available-for-sale	-	3,550	3,263
Receivables (net of allowance for doubtful accounts of $5,145, $5,913 and $6,452, respectively) -	153,873	110,831	145,839
Derivative assets	50,336	38,144	48,991
Other assets	43,099	29,992	27,546
Assets of discontinued operations	4,927	10,230	15,954
	306,581	222,703	277,633
Investments	19,520	59,895	60,274
Property, plant and equipment	1,763,873	1,564,664	1,302,728
Less accumulated depreciation and depletion	(389,561)	(328,325)	(301,759)
	1,374,312	1,236,339	1,000,969
Other assets:			
Derivatives assets	1,987	6,407	3,699
Goodwill	30,185	28,693	29,655
Intangible assets	93,760	86,528	15,447
Other	16,219	18,202	17,081
	142,151	139,830	65,882
	$1,842,564	$1,658,767	$1,404,758
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities:			
Accounts payable	$ 127,756	$ 96,218	$ 137,167
Accrued liabilities	58,904	39,085	47,954
Current maturities of long-term debt	36,457	35,904	14,470
Notes payable	406,109	360,450	71,400
Derivative liabilities	53,852	42,681	54,487
Liabilities of discontinued operations	6,294	8,960	13,613
	689,372	583,298	339,091
Long-term debt, net of current maturities	476,024	415,798	434,332
Deferred credits and other liabilities:			
Federal income taxes	77,672	75,162	62,193
Derivative liabilities	7,669	7,119	2,694
Other	40,202	42,693	39,348
	125,543	124,974	104,235
Minority interest in subsidiaries	22,546	19,533	27,246
Stockholders' equity:			
Preferred stock - no par Series 2000-A; 21,500 shares authorized; Issued and Outstanding: 5,177; 5,177 and 4,893 shares, respectively	5,549	5,549	5,175
Common stock equity-			
Common stock $1 par value; 100,000,000 shares authorized; Issued: 27,026,112; 26,890,943 and 26,769,144 shares, respectively	27,026	26,891	26,769
Additional paid-in capital	242,604	240,454	236,956
Retained earnings	262,741	250,515	244,406
Treasury stock, at cost	(1,756)	(4,503)	(8,841)
Accumulated other comprehensive loss	(7,085)	(3,742)	(4,611)
	523,530	509,615	494,679
Total stockholders' equity	529,079	515,164	499,854
	$1,842,564	$1,658,767	$1,404,758

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

BLACK HILLS CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(unaudited)

	Six Months June 30 2002	2001
	(in thousands)	
Operating activities:		
Net income available for common	$ 27,759	$ 66,602
Adjustments to reconcile net income available for common to net cash provided by operating activities:		
(Income) loss from discontinued operations	2,637	(980)
Depreciation, depletion and amortization	34,336	24,404
Net change in derivative assets and liabilities	(485)	(1,786)
Deferred income taxes	4,132	(486)
Undistributed earnings in associated companies	(3,964)	(7,342)
Minority interest	4,102	4,571
Accounting change	(896)	-
Change in operating assets and liabilities-		
Accounts receivable and other current assets	(51,732)	146,012
Accounts payable and other current liabilities	50,390	(106,193)
Other, net	(6,428)	(5,272)
	59,851	119,530
Investing activities:		
Property, plant and equipment additions	(109,920)	(235,915)
Payment for acquisition of net assets, net of cash acquired	(23,229)	(10,410)
Other, net	1,751	(57)
	(131,398)	(246,382)
Financing activities:		
Dividends paid on common stock	(15,533)	(13,429)
Treasury stock sold, net	2,747	226
Common stock issued	2,285	165,160
Increase (decrease) in short-term borrowings, net	45,659	(139,600)
Long-term debt - issuance	71,003	135,689
Long-term debt - repayments	(10,224)	(7,939)
Subsidiary distributions to minority interests	-	(1,505)
	95,937	138,602
Increase in cash and cash equivalents	24,390	11,750
Cash and cash equivalents:		
Beginning of period	29,956	24,290
End of period	$ 54,346	$ 36,040
Supplemental disclosure of cash flow information:		
Cash paid during the period for-		
Interest	$ 20,437	$ 19,954
Income taxes	$ 725	$ 34,800
Non-cash net assets acquired through issuance of common and preferred stock	$ -	$ 2,747

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

Notes to Condensed Consolidated Financial Statements
(unaudited)
(Reference is made to Notes to Consolidated Financial Statements
included in the Company's Annual Report on Form 10-K)

(1) MANAGEMENT'S STATEMENT

The financial statements included herein have been prepared by Black Hills Corporation (the Company) without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the footnotes adequately disclose the information presented. These financial statements should be read in conjunction with the financial statements and the notes thereto, included in the Company's 2001 Annual Report on Form 10-K filed with the Securities and Exchange Commission.

Accounting methods historically employed require certain estimates as of interim dates. The information furnished in the accompanying financial statements reflects all adjustments which are, in the opinion of management, necessary for a fair presentation of the June 30, 2002, December 31, 2001 and June 30, 2001, financial information and are of a normal recurring nature. The results of operations for the three, six and twelve months ended June 30, 2002, are not necessarily indicative of the results to be expected for the full year. All earnings per share amounts discussed refer to diluted earnings per share unless otherwise noted.

(2) RECLASSIFICATIONS

Certain 2001 amounts in the financial statements have been reclassified to conform to the 2002 presentation. These reclassifications did not have an effect on the Company's total stockholders' equity or net income available for common stock as previously reported.

(3) RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred with the associated asset retirement costs being capitalized as part of the carrying amount of the long-lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Management expects to adopt SFAS 143 effective January 1, 2003 and is currently evaluating the effects adoption will have on the Company's consolidated financial statements.

During June 2002, the Emerging Issues Task Force (EITF) reached a consensus on Issues 1 and 3 of EITF Issue No. 02-3, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," and No. 00-17, "Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10."

Under EITF 02-3, Issue 1 of the consensus requires mark-to-market gains and losses on energy trading contracts to be shown net on the income statement whether or not physically settled in financial statements issued for periods ending after July 15, 2002. Issue 3 requires entities involved in energy trading activities to include certain additional disclosures in financial statements issued for fiscal years ending after July 15, 2002. EITF 02-3 also requires that all comparative financial statements be reclassified to conform to EITF 02-3. Although EITF 02-3 will require the Company's mark-to-market gains and losses on energy trading contracts to be shown net on the income statement, it is not expected to impact the Company's net income, stockholders' equity or cash flows. The Company will adopt the guidance of Issue 1 during the third quarter, but has not yet quantified the financial statement effect from this adoption.

(4) RECENTLY ADOPTED ACCOUNTING PRONOUNCEMENTS

In June 2001, the FASB issued Statement of Financial Accounting Standards No. 141, "Business Combinations," (SFAS 141) and No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). The Company has adopted SFAS 141, which requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method of accounting. Under SFAS 142, goodwill and intangible assets with indefinite lives are no longer amortized but the carrying values are reviewed annually (or more frequently if impairment indicators arise) for impairment. If the carrying value exceeds the fair value, an impairment loss shall be recognized. A discounted cash flow approach was used to determine fair value of the Company's businesses for the purposes of testing for impairment. Intangible assets with a defined life will continue to be amortized over their useful lives (but with no maximum life). The Company adopted SFAS 142 on January 1, 2002.

The pro forma effects of adopting SFAS No. 142 for the three, six and twelve month periods ended June 30, 2002 and 2001 are as follows (in thousands):

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
Net income as reported	$13,807	$34,853	$27,871	$66,944	$49,004	$102,669
Cumulative effect of change in accounting principle, net of tax	-	-	(896)	-	(896)	-
Cumulative effect of change in accounting principle included in "Discontinued operations," net of tax	-	-	755	-	755	-
Income excluding cumulative effect of change in accounting principle	13,807	34,853	27,730	66,944	48,863	102,669
Add: goodwill amortization	-	463	-	871	447	2,051
Adjusted net income	$13,807	$35,316	$27,730	$67,815	$49,310	$104,720

The cumulative effect adjustment recognized upon adoption of SFAS 142 was $0.1 million (after tax), which had only a nominal impact on earnings per share. The adjustment consisted of income from the after-tax write-off of negative goodwill from prior acquisitions in our power generation segment of $0.9 million, offset by a $0.8 million after-tax write-off for the impairment of goodwill related to our discontinued coal marketing operations (Note 5). The goodwill impairment was a result of changes in the criteria for the measurement of impairments from an undiscounted to a discounted cash flow method. If SFAS 142 had been adopted on January 1, 2001, net income would have been lower for the six month period ended June 30, 2002 by $0.1 million, or 1 cent per share and higher for the twelve month period ended June 30, 2002 by $0.3 million, or 1 cent per share, respectively. The three, six and twelve month periods ended June 30, 2001 would have been higher by $0.5 million, or 2 cents per share, $0.9 million, or 4 cents per share, and $2.1 million, or 9 cents per share, respectively.

The substantial majority of the Company's goodwill and intangible assets are contained within the Power Generation segment. Changes to goodwill and intangible assets during the six-month period ended June 30, 2002, including the effects of adopting SFAS No. 142, but excluding amounts from discontinued operations, are as follows (in thousands):

	Goodwill	Other Intangible Assets
Balance at December 31, 2001, net of accumulated amortization	$28,693	$86,528
Change in accounting principle	1,492	-
Additions	-	9,504
Amortization expense	-	(2,272)
Balance at June 30, 2002, net of accumulated amortization	$30,185	$93,760

On June 30, 2002, intangible assets totaled $93.8 million, net of accumulated amortization of $6.7 million. Intangible assets are primarily related to site development fees and above-market long-term contracts, and all have definite lives ranging from 5 to 40 years, over which they continue to be amortized. Amortization expense for existing intangible assets is expected to be approximately $5.1 million to $4.5 million for each year from 2003 to 2007.

Intangible assets increased during the six month period ended June 30, 2002 as a result of a $9.5 million addition related to preliminary purchase allocations in the acquisition of additional ownership interest in the Harbor Cogeneration Facility (See Note 13). This intangible asset primarily relates to an acquired ownership of additional interest in a contract termination payment stream at the Facility.

In addition, during the first quarter of 2002, the Company had a $0.4 million (pre-tax) impairment loss of certain intangibles at the Company's discontinued coal marketing business as a result of a weak coal market. The intangible assets are included in "Assets of discontinued operations" on the accompanying Condensed Consolidated Balance Sheets and the related impairment loss is included in "(Loss) Income from discontinued operations" on the accompanying Condensed Consolidated Statements of Income.

In August 2001, the FASB issued SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". SFAS 144 supersedes FASB Statement 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of" (SFAS 121) and the accounting and reporting provisions of Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations - Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions" (APB 30). SFAS 144 establishes a single accounting model for long-lived assets to be disposed of by sale as well as resolves implementation issues related to SFAS 121. The Company adopted SFAS 144 effective January 1, 2002. Adoption did not have a material impact on the Company's consolidated financial position, results of operations or cash flows.

(5) DISCONTINUED OPERATION

During the second quarter of 2002, the Company adopted a plan to dispose of its coal marketing subsidiary, Black Hills Coal Network. The sale and disposal was finalized in July 2002. In connection with the plan of disposal, the Company determined that the carrying values of some of the underlying assets exceeded their fair values and a charge to operations was required.

Consequently, the Company recorded an after-tax charge of approximately $1.0 million, which represents the difference between the carrying values of the assets and liabilities of the subsidiary versus their fair values, less cost to sell. The disposition has been accounted for under the provisions of Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Accordingly, results of operations and the related charge have been classified as "Discontinued operations" in the accompanying Condensed Consolidated Statements of Income, and prior periods have been restated. For business segment reporting purposes, the coal marketing business results were previously included in the segment "Fuel Marketing."

Revenues and net income from the discontinued operation are as follows (in thousands):

	Three Months June 30		Six Months June 30		Twelve Months June 30	
	2002	2001	2002	2001	2002	2001
Revenues	$7,736	$14,648	$17,697	$28,661	$47,990	$47,294
Pre-tax income (loss) from discontinued operation	130	617	(2,744)	1,709	(3,567)	2,499
Pre-tax loss on disposal	(1,523)	-	(1,523)	-	(1,523)	-
Income tax benefit (expense)	481	(292)	1,630	(729)	1,966	(1,055)
Net (loss) income from discontinued operations	$ (912)	$ 325	$(2,637)	$ 980	$(3,124)	$ 1,444

Assets and liabilities of the discontinued operation are as follows (in thousands):

	June 30 2002	December 31 2001	June 30 2001
Current assets	$ 4,927	$7,878	$14,184
Non-current assets	-	2,352	1,770
Current liabilities	(5,345)	(8,724)	(13,613)
Non-current liabilities	(949)	(236)	-
Net assets (liabilities) of discontinued operations	$ (1,367)	$1,270	$ 2,341

(6) EARNINGS PER SHARE

Basic earnings per share is computed by dividing net income by the weighted average number of common shares outstanding during the period. Diluted earnings per share gives effect to all dilutive potential common shares outstanding during a period. A reconciliation of "Income from continuing operations" and basic and diluted share amounts is as follows:

Periods ended June 30, 2002	Three Months		Six Months		Twelve Months	
(in thousands)	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$14,719		$29,612		$51,232	
Less: preferred stock dividends	(56)		(112)		(297)	
Basic - available for common shareholders	14,663	26,804	29,500	26,749	50,935	26,610
Dilutive effect of:						
Stock options	-	148	-	122	-	146
Convertible preferred stock	56	148	112	148	297	148
Others	-	26	-	26	-	26
Diluted - available for common shareholders	$14,719	27,126	$29,612	27,045	$51,232	26,930

Periods ended June 30, 2001 (in thousands)	Three Months		Six Months		Twelve Months	
	Income	Average Shares	Income	Average Shares	Income	Average Shares
Income from continuing operations	$34,528		$65,964		$101,225	
Less: preferred stock dividends	(300)		(342)		(420)	
Basic - available for common shareholders	34,228	25,502	65,622	24,245	100,805	23,550
Dilutive effect of:						
Stock options	-	306	-	278	-	301
Convertible preferred stock	300	140	342	140	420	137
Others	-	30	-	28	-	26
Diluted - available for common shareholders	$34,528	25,978	$65,964	24,691	$101,225	24,014

(7) COMPREHENSIVE INCOME

The following table presents the components of the Company's comprehensive income:

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
			(in thousands)			
Net income	$13,807	$34,853	$27,871	$66,944	$49,004	$102,669
Other comprehensive income:						
Unrealized gain (loss) on available-for-sale securities	-	127	(219)	1,151	68	(150)
Reclassification adjustment for unrealized gain on available-for-sale securities included in net income	(406)	-	(406)	-	(406)	-
Initial impact of adoption of SFAS 133, net of minority interest	-	-	-	(7,518)	-	(7,518)
Fair value adjustment on derivatives designated as cash flow hedges	(3,227)	5,005	(2,718)	2,569	(2,136)	2,569
Comprehensive income	$10,174	$39,985	$24,528	$63,146	$46,530	$97,570

(8) CHANGES IN COMMON STOCK

Other than the following transactions, the Company had no other changes in its common stock, as reported in Note 4 of the Company's 2001 Annual Report on Form 10-K.

- The Company granted 95,220 stock options at a weighted average exercise price of $34.64 per share.
- 110,864 stock options were exercised at a weighted average exercise price of $20.84 per share.
- The Company issued 26,047 restricted shares of common stock to certain officers. Pre-tax compensation cost related to the award was $0.9 million, which is being expensed over the vesting period ranging from two to three years.
- The Company issued 16,256 shares of common stock under its dividend reinvestment plan.
- The Company issued 8,099 shares of common stock under its employee stock purchase plan at a price of $27.08 per share.
- The Company issued 45,043 shares of common stock under the short-term incentive compensation plan.

(9) CHANGES IN LONG-TERM DEBT AND NOTES PAYABLE

On January 4, 2002, the Company closed on a $50.0 million bridge credit agreement. The credit agreement supplements our revolving credit facilities in place at December 31, 2001 and has the same terms as those facilities with an expiration date that has now been extended to August 28, 2002. This bridge facility was fully drawn at June 30, 2002.

On March 15, 2002, the Company closed on $135 million of senior secured financing for the Arapahoe and Valmont Facilities. These projects have a total of 210 megawatts in service and under construction and are located in the Denver, Colorado area. Proceeds from this financing were used to refinance $53.8 million of an existing seven-year senior secured term project-level facility, pay down approximately $50.0 million of short-term credit facility borrowings and approximately $31.2 million will be used for future project construction. At June 30, 2002, $124.9 million of the $135 million financing has been utilized.

On June 18, 2002, we closed on a $75 million bridge credit agreement. As of June 30, 2002, there were no borrowings outstanding under this bridge credit agreement. This credit agreement bridges the issuance of $75 million of Black Hills Power First Mortgage Bonds, which we issued on August 13, 2002. The termination date of the bridge credit agreement was August 13, 2002, the date on which the First Mortgage Bonds were issued.

On June 28, 2002, Enserco Energy closed on a $135 million uncommitted, discretionary credit facility, which became effective July 1, 2002 and expires June 27, 2003. This facility replaced the $75 million Enserco Energy facility.

Our credit facilities include certain restrictive covenants that are common in such arrangements. Such covenants include a consolidated net worth in an amount of not less than the sum of $375 million and 50 percent of the aggregate consolidated net income beginning June 30, 2001; a recourse leverage ratio not to exceed 0.65 to 1.00; an interest coverage ratio of not less than 3.00 to 1.00; and restrictions on the ability to dividend cash to the parent company at certain subsidiaries with project level financing approximately $23 million at June 30, 2002. If these covenants are violated, it would be considered an event of default entitling the lender to terminate the remaining commitment and accelerate all principal and interest outstanding to become immediately due. In addition, certain of our interest rate swap agreements include cross-default provisions. These provisions would allow the counterparty the right to terminate the swap agreement and liquidate at a prevailing market rate, in the event of default. The Company and its subsidiaries complied with all the covenants at June 30, 2002.

Some of the facilities previously had a covenant whereby we were required to maintain a credit rating of at least "BBB-" from Standard & Poor's or "Baa3" from Moody's Investor Service. The facilities that contained the rating triggers were amended during the second quarter of 2002 to remove default provisions pertaining to our credit rating status.

Other than the above transactions, the Company had no other material changes in its consolidated indebtedness, as reported in Notes 6 and 7 of the Company's 2001 Annual Report on Form 10-K.

(10) SUMMARY OF INFORMATION RELATING TO SEGMENTS OF THE COMPANY'S BUSINESS

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business groups due to differences in products, services and regulation. As of June 30, 2002, substantially all of the Company's operations and assets are located within the United States. The Company's operations are conducted through six reporting segments that include: Electric group and segment, which supplies electric utility service to western South Dakota, northeastern Wyoming and southeastern Montana; Integrated Energy group consisting of the following segments: Mining, which engages in the mining and sale of coal from its mine near Gillette, Wyoming; Oil and Gas, which produces, explores and operates oil and gas interests located in the Rocky Mountain region, Texas, California and other states; Fuel Marketing, which markets natural gas, oil and related services to customers in the Midwest, Southwest, Rocky Mountain, West Coast and Northwest regions; Power Generation, which produces and sells power to wholesale customers; and Communications group and Others, which primarily markets communications and software development services.

Segment information follows the same accounting policies as described in Note 1 of the Company's 2001 Annual Report on Form 10-K. In accordance with the provisions of SFAS No. 71, intercompany coal sales are not eliminated. Segment information included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income is as follows (in thousands):

	External Operating Revenues	Inter-segment Operating Revenues	Income (loss) from Continuing Operations
Quarter to Date June 30, 2002			
Fuel marketing	$296,064	$ 2,642	$ 2,397
Power generation	39,099	-	4,174
Oil and gas	6,260	606	1,283
Mining	4,259	2,622	2,494
Electric	38,253	50	6,792
Communications	7,752	465	(2,049)
Corporate	-	-	(365)
Intersegment eliminations	-	(3,763)	(7)
Total	$391,687	$ 2,622	$14,719

	External Operating Revenues	Inter-segment Operating Revenues	Income (loss) from Continuing Operations
Quarter to Date June 30, 2001			
Fuel marketing	$297,432	$ 9,403	$11,468
Power generation	24,975	-	3,687
Oil and gas	8,251	1,024	2,963
Mining	5,237	2,644	2,307
Electric	61,280	321	16,784
Communications	4,582	1,117	(2,792)
Corporate	-	-	365
Intersegment eliminations	-	(11,865)	(254)
Total	$401,757	$ 2,644	$34,528

Year to Date June 30, 2002	External Operating Revenues	Inter-segment Operating Revenues	Income (loss) from Continuing Operations
Fuel marketing	$498,165	$ 3,809	$ 3,903
Power generation	71,182	-	8,951
Oil and gas	11,651	1,304	2,161
Mining	9,709	5,374	4,829
Electric	75,362	132	14,614
Communications	14,933	830	(4,276)
Corporate	-	-	(563)
Intersegment eliminations	-	(6,077)	(7)
Total	$681,002	$ 5,372	$29,612

Year to Date June 30, 2001	External Operating Revenues	Inter-segment Operating Revenues	Income (loss) from Continuing Operations
Fuel marketing	$735,718	$12,994	$26,373
Power generation	43,020	-	2,582
Oil and gas	16,833	1,024	5,919
Mining	10,658	5,486	4,623
Electric	131,858	322	34,124
Communications	8,508	2,217	(6,682)
Corporate	-	-	(467)
Intersegment eliminations	-	(16,557)	(508)
Total	$946,595	$ 5,486	$65,964

12 Months Ended June 30, 2002	External Operating Revenues	Inter-segment Operating Revenues	Income (loss) from Continuing Operations
Fuel marketing	$ 872,572	$ 6,632	$12,095
Power generation	122,456	-	7,945
Oil and gas	25,436	3,069	6,439
Mining	19,602	11,136	11,798
Electric	155,859	665	25,730
Communications	26,683	2,862	(9,894)
Corporate	-	-	(2,656)
Intersegment eliminations	-	(13,230)	(225)
Total	$1,222,608	$11,134	$51,232

12 Months Ended June 30, 2001	External Operating Revenues	Inter-segment Operating Revenues	Income (loss) from Continuing Operations
Fuel marketing	$1,579,366	$ 26,170	$ 38,767
Power generation	82,193	329	5,694
Oil and gas	27,782	2,169	8,783
Mining	22,478	10,283	7,714
Electric	235,915	376	56,943
Communications	14,392	3,987	(14,495)
Corporate	-	-	(1,390)
Intersegment eliminations	-	(33,031)	(791)
Total	$1,962,126	$ 10,283	$101,225

Other than the following transactions, the Company had no other material changes in total assets of its reporting segments, as reported in Note 14 of the Company's 2001 Annual Report on Form 10-K, beyond discontinuing the coal marketing operations (Note 5) previously included in the "Fuel Marketing" segment and changes resulting from normal operating activities.

The Power Generation segment had a net addition to non working capital assets of approximately $75 million primarily related to ongoing construction of the expansions at the Las Vegas Cogeneration and Arapahoe facilities and the acquisition of additional ownership interest at the Harbor Cogeneration facility (Note 13).

The Fuel Marketing segment acquired additional ownership interest in a pipeline company for $11.0 million (Note 13).

(11) RISK MANAGEMENT ACTIVITIES

The Company actively manages its exposure to certain market risks as described in Note 2 of the Company's Annual Report on Form 10-K. Details of derivative and hedging activities included in the accompanying Condensed Consolidated Balance Sheets and Condensed Consolidated Statements of Income are as follows:

Energy Marketing Activities

The Company's energy marketing operations fall under the purview of Statement of Financial Accounting Standard No. 133 (SFAS 133), "Accounting for Derivative Instruments and Hedging Activities" and Emerging Issues Task Force Issue No. 98-10, "Accounting for Energy Trading and Risk Management Activities" (EITF 98-10). As such, these activities are accounted for under mark-to-market accounting. The Company records the fair values of its trading derivatives as either Derivative assets and/or Derivative liabilities on the accompanying Condensed Consolidated Balance Sheet. The net mark-to-market gains or losses are recorded as Revenues in the accompanying Condensed Consolidated Statements of Income. During the second quarter 2002, the Company's gas marketing subsidiary revised its estimates of fair values for certain derivatives valued using market based prices which include a "bid/offer" spread. The change in estimate resulted in a $0.8 million reduction in net income versus amounts that would have been reported if the change in estimate had not occurred.

The contract or notional amounts and terms of the Company's derivative commodity instruments held for trading purposes are set forth below:

	June 30, 2002		December 31, 2001		June 30, 2001	
(thousands of MMBtu's)	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years	Notional Amounts	Maximum Term in Years
Natural gas basis swaps purchased	44,871	1	9,882	1	29,064	2
Natural gas basis swaps sold	53,504	1	10,696	1	29,284	2
Natural gas fixed-for float swaps purchased	20,783	1	10,646	2	15,470	1
Natural gas fixed-for-float swaps sold	24,723	1	11,815	2	11,728	1
Natural gas swing swaps purchased	-	-	465	1	1,045	1
Natural gas swing swaps sold	-	-	930	1	12,624	1
Natural gas physical purchases	40,431	1	13,159	1	22,184	1
Natural gas physical sales	46,909	1	19,339	1	26,945	1
Transport purchase	51,273	5	41,136	6	30,891	6
(thousands of barrels)						
Crude oil purchased	4,002	1	3,139	1	2,655	1
Crude oil sold	4,038	1	3,142	1	2,538	1
(megawatthours)						
Power purchased	30,400	1	-	-	-	-
Power sold	30,400	1	-	-	-	-

As required under SFAS 133 and EITF 98-10, derivatives and energy trading activities were marked to fair value and the gains and/or losses recognized in earnings. The amounts related to the accompanying Condensed Consolidated Balance Sheets and Statements of Income as of June 30, 2002, December 31, 2001, and June 30, 2001, are as follows (in thousands):

June 30, 2002	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Unrealized Gain
Natural gas	$43,960	$ 1,831	$38,933	$1,146	$5,712
Crude Oil	5,724	-	4,959	-	765
Power	243	-	95	-	148
	$49,927	$ 1,831	$43,987	$1,146	$6,625
December 31, 2001					
Natural gas	$29,755	$ 661	$25,437	$ 953	$4,026
Crude Oil	6,267	-	5,497	-	770
	$36,022	$ 661	$30,934	$ 953	$4,796
June 30, 2001					
Natural gas	$40,555	$3,699	$38,960	$2,694	$2,600
Crude oil	7,153	-	6,475	-	678
	$47,708	$3,699	$45,435	$2,694	$3,278

At June 30, 2002, the Company had a mark to fair value unrealized gain of $6.6 million for its energy marketing activities. Of this amount, $5.9 million was current and $0.7 million was non-current. Substantially all of the unrealized gain at June 30, 2002 results from "back to back" transactions. The Company anticipates that substantially all of the current portion of unrealized gains for hedged transactions will be realized during the next twelve months.

Non-trading Energy Activities

On June 30, 2002, December 31, 2001 and June 30, 2001, the Company had the following swaps and related balances for its non-trading energy operations (in thousands):

	Notional*	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Income (Loss)
June 30, 2002								
Crude oil swaps	270,000	1	$ -	$ -	$ 739	$ -	$ (556)	$(183)
Natural gas swaps	1,320,000	1	409	-	336	-	71	2
			$ 409	$ -	$ 1,075	$ -	$ (485)	$(181)
December 31, 2001								
Crude oil swaps	90,000	1	$ 529	$ -	$ -	$ -	$ 529	$ -
Natural gas swaps	1,216,000	1	1,593	-	-	-	1,463	130
			$2,122	$ -	$ -	$ -	$ 1,992	$ 130
June 30, 2001								
Crude oil swaps	192,000	1	$ 298	$ -	$ -	$ -	$ 378	$ (80)
Crude oil options	60,000	1	92	-	-	-	75	17
Natural gas swaps	676,000	1	893	-	-	-	893	-
			$1,283	$ -	$ -	$ -	$ 1,346	$ (63)

*crude in bbls, gas in MMBtu's

Based on June 30, 2002 market prices, $(0.5) million will be realized and reported in earnings during the next twelve months. These estimated realized losses for the next twelve months were calculated using June 30, 2002 market prices. Estimated and actual realized losses will likely change during the next twelve months as market prices change.

Financing Activities

On June 30, 2002, December 31, 2001 and June 30, 2001, the Company's interest rate swaps and related balances were as follows (in thousands):

	Current Notional Amount	Weighted Average Fixed Interest Rate	Maximum Terms in Years	Current Derivative Assets	Non-current Derivative Assets	Current Derivative Liabilities	Non-current Derivative Liabilities	Pre-tax Accumulated Other Comprehensive Income (Loss)	Pre-tax Income (Loss)
June 30, 2002									
Swaps on project financing	$215,017	6.00%	4	$ -	$ 156	$ 7,514	$ 6,255	$(13,551)	$ (62)
Swaps on corporate debt	75,000	4.45%	2	-	-	1,276	268	(1,544)	-
Total	$290,017			$ -	$ 156	$ 8,790	$ 6,523	$(15,095)	$ (62)
December 31, 2001									
Swaps on project financing	$316,397	5.85%	4	$ -	$5,746	$10,212	$ 5,949	$(10,415)	$ -
Swaps on corporate debt	75,000	4.45%	3	-	-	1,535	217	(1,752)	-
Total	$391,397			$ -	$5,746	$11,747	$ 6,166	$(12,167)	$ -
June 30, 2001									
Swaps on project financing	$126,161	7.36%	5	$ -	$ -	$ 8,603	$ -	$ (8,603)	$ -
Swaps on corporate debt	50,000	5.19%	3	-	-	449	-	(449)	-
Total	$176,161			$ -	$ -	$ 9,052	$ -	$ (9,052)	$ -

Based on June 30, 2002 market interest rates, approximately $8.8 million will be realized as additional interest expense during the next twelve months. Estimated and realized amounts will likely change during the next twelve months as market interest rates change.

At December 31, 2001, the Company had a $100 million forward starting floating-to-fixed interest rate swap to hedge the anticipated floating rate debt financing related to the Company's Las Vegas Cogeneration expansion. This swap terminated during the second quarter 2002 and resulted in a $1.1 million gain. This swap was treated as a cash flow hedge and accordingly the resulting gain will continue to be carried in Accumulated Other Comprehensive Income on the Condensed Consolidated Balance Sheet and amortized over the life of the related long-term financing.

In addition, the Company entered into a $50 million treasury lock to hedge a portion of the Company's $75 million First Mortgage Bond offering completed in August 2002 (Note 14). The treasury lock effectively fixes, at current rates, the interest rate for the first 28.5 years of the 30-year bonds. The treasury lock cash settled on August 8, 2002, the bond pricing date, and resulted in a loss which will continue to be carried in Accumulated Other Comprehensive Income on the Condensed Consolidated Balance Sheet and amortized over the life of the related bonds as additional interest expense. At June 30, 2002, the treasury lock had a fair market value of $0.

(12) LEGAL PROCEEDINGS

In June 2002, a forest fire damaged approximately 10,800 acres of private and government land located near Deadwood and Lead, South Dakota. The fire destroyed approximately 20 structures (seven houses and 13 outbuildings) and caused the evacuation of the cities of Lead and Deadwood for approximately 48 hours.

The cause of the fire was investigated by the State of South Dakota. Sagging power lines owned by us were implicated as the cause. We have initiated our own investigation into the cause of the fire, including the hiring of expert fire investigators, and that investigation is continuing.

Although we have been put on notice of potential claims, no civil action or regulatory proceeding has been initiated against us at this time. If, however, it is determined that sagging power lines owned by us were the cause of the fire and that we were negligent in the maintenance of those power lines, we could be liable for resultant damages. Although we cannot predict the outcome of either our investigation or of potential claims, management believes that any such claims will not have a material adverse effect on our financial condition or results of operations.

(13) ACQUISITIONS

On March 8, 2002, the Company acquired an additional 67 percent ownership interest in Millennium Pipeline Company L.P., which owns and operates a 200-mile pipeline. The pipeline has a capacity of approximately 65,000 barrels of oil per day, and transports imported crude oil from Beaumont, Texas to Longview, Texas, which is the transfer point to connecting carriers. The Company also acquired additional ownership interest in Millennium Terminal Company, L.P., which has 1.1 million barrels of crude oil storage connected to the Millennium Pipeline at the Oil Tanking terminal in Beaumont. The millennium system is presently operating near capacity through shipper agreements. These acquisitions give the Company 100 percent ownership in the Millennium companies. Total cost of the acquisitions was $11.0 million and was funded through borrowings under short-term revolving credit facilities.

On March 15, 2002, the Company paid $25.7 million to acquire an additional 30 percent interest in the Harbor Cogeneration Facility (the Facility), a 98-megawatt gas-fired plant located in Wilmington, California. This acquisition was funded through borrowings under short-term revolving credit facilities and gives the Company an 83 percent ownership interest and voting control of the Facility.

The Company's investments in these entities prior to the above acquisitions were accounted for under the equity method of accounting and included in Investments on the accompanying Condensed Consolidated Balance Sheets. Each of the above acquisitions gave the Company majority ownership and voting control of the respective entities, therefore, the Company now includes the accounts of each of the entities in its consolidated financial statements.

The above acquisitions have been accounted for under the purchase method of accounting and, accordingly, the purchase prices have been allocated to the acquired assets and liabilities based on preliminary estimates of the fair values of the assets purchased and the liabilities assumed as of the date of acquisition. The estimated purchase price allocations are subject to adjustment, generally within one year of the date of the acquisition. The purchase prices and related acquisition costs exceeded the fair values assigned to net tangible assets by approximately $9.5 million, which was recorded as long-lived intangible assets.

The impact of these acquisitions was not material in relation to the Company's results of operations. Consequently, pro forma information is not presented.

(14) SUBSEQUENT EVENT

During July 2002, the Company's integrated energy subsidiary, Black Hills Energy Resources, purchased the assets of the Kilgore to Houston Pipeline System from Equilon Pipeline Company, LLC. The Kilgore pipeline transports crude oil from the Kilgore, Texas region south to Houston, Texas, which is the transfer point to connecting carriers via the Oiltanking Houston terminal facilities. The 10-inch pipeline is approximately 190 miles long and has a capacity of up to approximately 35,000 barrels per day. In addition, the Kilgore system has approximately 400,000 barrels of crude oil storage at Kilgore and 375,000 barrels of storage at the Texoma Tank Farm located in Longview, Texas. Total cost of the acquisition was $6.7 million and was funded through borrowings under short-term credit facilities.

On August 13, 2002, the Company issued $75 million of First Mortgage Bonds, Series AE, due 2032. The Mortgage Bonds have a 7.23% coupon with interest payable semi-annually, commencing February 15, 2003. Net proceeds from the offering were and will be used to fund the Company's portion of construction and installation costs for an AC-DC-AC Converter Station; for general capital expenditures for the remainder of 2002 and 2003; to repay a portion of current bank indebtedness; to satisfy bond maturities for certain outstanding first mortgage bonds due in 2003; and for general corporate purposes.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

We are a growth oriented, diversified energy holding company operating principally in the United States. Our unregulated and regulated businesses have expanded significantly in recent years. Our integrated energy group, Black Hills Energy, Inc., produces and markets electric power and fuel. We produce and sell electricity in a number of markets, with a strong emphasis in the western United States. We also produce coal, natural gas and crude oil, primarily in the Rocky Mountain region, and market fuel products nationwide. Our electric utility, Black Hills Power, Inc., serves approximately 59,200 customers in South Dakota, Wyoming and Montana. Our communications group offers state-of-the-art broadband communications services to residential and business customers in Rapid City and the northern Black Hills region of South Dakota through Black Hills FiberCom, LLC.

The following discussion should be read in conjunction with Item 7. - Management's Discussion and Analysis of Financial Condition and Results of Operations - included in our 2001 Annual Report on Form 10-K filed with the Securities and Exchange Commission. Our business strategy, industry outlooks, capital requirements and market risks as disclosed in that filing continue to be consistent with management's current expectations and assessments.

Results of Operations

Consolidated Results

Revenue and net income (loss) from continuing operations provided by each business group as a percentage of our total revenue and net income were as follows:

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
Revenues						
Integrated energy	88%	84%	87%	85%	85%	87%
Electric utility	10	15	11	14	13	12
Communications	2	1	2	1	2	1
	100%	100%	100%	100%	100%	100%
Net Income/(Loss) from Continuing Operations						
Integrated energy	69%	59%	66%	59%	71%	58%
Electric utility	46	48	49	51	49	56
Communications and other	(15)	(7)	(15)	(10)	(20)	(14)
	100%	100%	100%	100%	100%	100%

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001. Consolidated income from continuing operations for the three month period ended June 30, 2002 were $14.7 million or $0.54 per share compared to $34.5 million or $1.33 per share in the same period of the prior year.

The decrease in income from continuing operations was a result of substantial decreases in prevailing prices for natural gas, crude oil and wholesale electricity and in gross margins from natural gas marketing activities compared to the same period in 2001. Unusual energy marketing conditions existed in the second quarter of 2001 stemming primarily from gas and electricity shortages in the West. More than half of the 2001 second quarter income from continuing operations was attributed to the unusual market conditions that existed at that time. Wholesale electricity average peak prices at Mid-Columbia were around $210 per megawatt-hour during the second quarter of 2001 compared to approximately $18 per megawatt-hour during the second quarter of 2002. Average spot gas prices in the West Coast region were approximately $9 per MMBtu in the second quarter of 2001 compared to $3 in the second quarter of 2002. While the above factors contributed negatively to income from continuing operations, we had an increase in the production of coal, oil and natural gas, an increase in independent power generation capacity and our communications business group showed a decrease in its net loss attributable to a substantial expansion of its customer base. Changes in commodity prices also resulted in unrealized gains recognized through mark-to-market accounting at our Fuel Marketing segment having a positive impact on 2002 income from continuing operations compared to 2001.

In addition, during the second quarter of 2002 we decided to discontinue operations in our coal marketing business due primarily to challenges encountered in marketing our Wyodak coal from the Powder River Basin of Wyoming to midwestern and eastern coal markets. We sold the non-strategic assets effective August 1, 2002. Income (loss) from discontinued operations were ($0.9) million or ($0.03) per share for the three months ended June 30, 2002 compared to $0.3 million or $0.01 per share for the same period of the prior year. Prior year results of operations have been restated to reflect the discontinued operations.

Consolidated revenues for the three-month period ended June 30, 2002 were $394.3 million compared to $404.4 million for the same period in 2001. The decrease in revenues was a result of the high energy commodity prices in 2001, slightly offset by increased revenue in the communications business unit and power generation segment and increased production of coal, oil and gas.

Consolidated operating expenses for the three-month period increased from $341.1 million in 2001 to $361.4 million in 2002. The increase was due to an increase in fuel and depreciation expense as a result of our increased investment in independent power generation offset by a substantial decrease in gas prices as discussed above. Administrative and general expense decreased 19 percent primarily due to a decrease in incentive compensation.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001. Consolidated income from continuing operations for the six month period ended June 30, 2002 were $29.6 million or $1.09 per share compared to $66.0 million or $2.67 per share in the same period of the prior year.

The decrease in income from continuing operations was a result of substantial decreases in prevailing prices for natural gas, crude oil and wholesale electricity and in gross margins from natural gas marketing activities compared to the same period in 2001. Unusual energy marketing conditions existed in the first half of 2001 stemming primarily from gas and electricity shortages in the West. Approximately half of the 2001 year to date income from continuing operations was attributed to the unusual market conditions that existed at that time. Wholesale electricity average peak prices at Mid-Columbia were around $250 per megawatt-hour during the first half of 2001 compared to approximately $22 per megawatt-hour during the first half of 2002. Average spot gas prices in the West Coast region were approximately $11 per MMBtu in the first half of 2001 compared to $3 in the first half of 2002. While the above factors contributed negatively to income from continuing operations, we had an increase in the production of coal, oil and natural gas, an increase in independent power generation capacity and our communications business group showed a decrease in its net loss attributable to a substantial expansion of its customer base.

In addition, during the second quarter of 2002 we decided to discontinue operations in our coal marketing business due to challenges encountered to market its Wyodak coal from the Powder River Basin of Wyoming to East Coast markets. We sold the non-strategic assets effective August 1, 2002. Income (loss) from discontinued operations were $(2.6) million or $(0.09) per share for the six months ended June 30, 2002 compared to $1.0 million or $0.04 per share for the same period of the prior year. Prior year results of operations have been restated to reflect the discontinued operations.

Consolidated revenues for the six-month period ended June 30, 2002 were $686.4 million compared to $952.1 million for the same period in 2001. The decrease in revenues was a result of the high energy commodity prices in 2001, slightly offset by increased revenue in the communications business unit and power generation segment and increased production in coal, oil and gas.

Consolidated operating expenses for the six-month period decreased from $828.3 million in 2001 to $621.7 million in 2002. The decrease was due to a substantial decrease in gas prices as discussed above. Administrative and general expenses decreased 32 percent primarily due to a decrease in incentive compensation. Depreciation, depletion and amortization expense increased from $24.4 million in 2001 to $34.3 million in 2002 primarily as a result of our increased investment in independent power generation.

Twelve Months Ended June 30, 2002 Compared to Twelve Months Ended June 30, 2001. Consolidated income from continuing operations for the twelve month period ended June 30, 2002 were $51.2 million or $1.90 per share compared to $101.2 million or $4.22 per share for the same period of the prior year.

The decrease in income from continuing operations for the twelve month period ended June 30, 2002 was a result of the substantial decrease in prevailing prices for natural gas, crude oil and wholesale electricity and in the gross margins from natural gas marketing activities compared to the same period of 2001. We estimate approximately $1.80 of the earnings per share for the twelve month period ended June 30, 2001 could have been attributable to high prices of natural gas and electricity related to the volatile western markets during that period of time.

The decrease in income from continuing operations also reflects the following special items for the twelve months ended June 30, 2002: a $4.4 million after-tax charge related to a long-term fuel swap with Enron Corporation to provide natural gas to a power plant; a $2.0 million after-tax non-cash charge related to the contribution of Black Hills Corporation Common Stock to the newly formed Black Hills Corporation Foundation; a $1.1 million after-tax non-cash employee stock bonus taken in the form of Black Hills Corporation common stock; a $1.7 million after-tax gain on the sale of mining equipment; a $3.6 million after-tax benefit related to a coal contract settlement; and a $1.9 million after-tax benefit related to the collection of amounts previously reserved for California operations in the prior twelve month period.

In addition, during the second quarter of 2002 we decided to discontinue operations in our coal marketing business due primarily to challenges encountered in marketing our Wyodak coal from the Powder River Basin of Wyoming to midwestern and eastern coal markets. We sold the non-strategic assets effective August 1, 2002. Income from discontinued operations were ($3.1) million or ($0.11) per share for the twelve months ended June 30, 2002 compared to $1.4 million or $0.06 per share for the same period of the prior year. Prior year results of operations have been restated to reflect the discontinued operations.

Consolidated revenues for the twelve-month period ended June 30, 2002 were $1.2 billion compared to $2.0 billion for the same period in 2001. The decrease in revenues was a result of the high energy commodity prices in late 2000 and the first half of 2001.

Consolidated operating expenses for the twelve-month period decreased from $1.8 billion in 2001 to $1.1 billion in 2002. Fuel and purchased power costs decreased 42 percent due to the substantial decrease in commodity prices as discussed above. Administrative and general expense decreased 14 percent primarily due to a decrease in incentive compensation. All other operating expenses increased due to our growth primarily in the power generation segment and communications business group.

The following business group and segment information does not include intercompany eliminations:

Integrated Energy Group

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
	(in thousands)					
Revenue:						
Fuel marketing	$298,706	$306,835	$501,974	$748,712	$ 879,204	$1,605,536
Power generation	39,099	24,975	71,182	43,020	122,456	82,522
Oil and gas	6,866	9,275	12,955	17,857	28,505	29,951
Mining	6,881	7,881	15,083	16,144	30,738	32,761
Total revenue	$351,552	$348,966	$601,194	$825,733	$1,060,903	$1,750,770
Expenses	329,301	312,141	558,857	753,390	993,165	1,630,138
Operating income	$ 22,251	$ 36,825	$ 42,337	$ 72,343	$ 67,738	$ 120,632
Net income	$ 10,119	$ 20,450	$ 20,308	$ 38,690	$ 37,370	$ 59,227
EBITDA	$ 31,866	$ 43,551	$ 61,448	$ 83,787	$ 113,660	$ 133,163

EBITDA represents earnings before interest, income taxes, depreciation and amortization. EBITDA is used by management and some investors as an indicator of a company's historical ability to service debt. Management believes that an increase in EBITDA is an indicator of improved ability to service existing debt, to sustain potential future increases in debt and to satisfy capital requirements. However, EBITDA is not intended to represent cash flows for the period, nor has it been presented as an alternative to either operating income, or as an indicator of operating performance or cash flows from operating, investing and financing activities, as determined by generally accepted accounting principles. EBITDA as presented may not be comparable to other similarly titled measures of other companies.

The following is a summary of sales volumes of our coal, oil and natural gas production and various measures of power generation:

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
Fuel production:						
Tons of coal sold	843,500	775,000	1,844,700	1,592,800	3,770,100	3,264,400
Barrels of oil sold	115,357	110,350	229,633	209,017	466,076	380,617
Mcf of natural gas sold	1,259,719	1,015,300	2,547,571	2,021,800	5,145,428	3,891,900
Mcf equivalent sales	1,951,861	1,677,400	3,925,369	3,275,900	7,941,884	6,175,600

	June 30	
	2002	2001
Independent power capacity:		
MWs of independent power capacity in service	646	327
MWs of independent power capacity under construction*	364	438

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*includes a 90 MW plant under a lease arrangement

The following is a summary of average daily fuel marketing volumes:

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
Natural gas - MMBtus	1,131,800	912,700	987,935	889,600	1,096,500	942,200
Crude oil - barrels	59,900	38,400	51,900	37,900	43,480	40,800

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001. Net income for the integrated energy group for the three months ended June 30, 2002 was $10.1 million compared to $20.5 million in the same period of the prior year. Net income decreased primarily due to a substantial decline in energy prices. The power generation segment reported net income growth attributed to additional generating capacity. A 16 percent increase in gas and oil production sales partially offset a decrease in net income in the oil and gas segment caused by lower prices. The fuel marketing segment's net income decreased primarily due to a substantial decrease in margins received offset by unrealized gains recognized through mark-to-market accounting as a result of changes in commodity prices.

The integrated energy business group's revenues and expenses increased 1 percent and 5 percent respectively for the three months ended June 30, 2002 compared to the same period in 2001. The increase in revenue was a result of increased generation capacity offset by the substantial decline in fuel and power prices. Expenses increased due to higher fuel costs and depreciation expense resulting from increased capacity.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001. Net income for the integrated energy group for the six months ended June 30, 2002 were $20.3 million compared to $38.7 million in the same period of the prior year. Net income decreased primarily due to a substantial decline in energy prices. The power generation segment reported net income growth attributed to additional generating capacity and the reporting of additional net income relating to the collection in 2002 of receivables from California operations that were reserved for in the prior period. A 20 percent increase in gas and oil production sales partially offset an earnings decrease in the oil and gas segment caused by lower prices. The fuel marketing segment's net income decreased primarily due to a substantial decrease in margins received.

The integrated energy business group's revenues and expenses decreased 27 percent and 26 percent, respectively, for the six months ended June 30, 2002 compared to the same period in 2001. The decrease in revenue and expenses was a direct result of the substantial decline in fuel and power prices.

Twelve Months Ended June 30, 2002 Compared to Twelve Months Ended June 30, 2001. Net income for the integrated energy group for the twelve months ended June 30, 2002 were $37.4 million compared to $59.2 million for the same period of the prior year, a 37 percent decrease. Increases in net income in the power generation and mining segments were more than offset by a decrease in oil and gas and fuel marketing net income. The power generation segment reported net income growth attributed to additional generating capacity and the reporting of additional net income relating to the collection in 2002 of receivables from California operations that were reserved for in the prior twelve month period. Net income from mining operations increased as a result of a 15 percent increase in production, a coal contract settlement and a gain on the sale of mining equipment offset by lower prices received. A 29 percent increase in gas and oil production sales was offset by lower prices. The fuel marketing segments net income decreased primarily due to a substantial decrease in margins received. These decreases were partially offset by a 16 percent increase in the daily volumes of natural gas marketed.

The integrated energy business group's revenues and expenses both decreased 39 percent, for the twelve months ended June 30, 2002 compared to the same period in 2001. The decrease in revenue and expenses was a direct result of the substantial decline in fuel and power prices.

Fuel Marketing

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
			(in thousands)			
Revenue	$298,706	$306,835	$501,974	$748,712	$879,204	$1,605,536
Operating income	$ 3,508	$ 18,144	$ 5,371	$ 42,352	$ 15,716	$ 63,219
Net income	$ 2,397	$ 11,468	$ 3,903	$ 26,373	$ 12,095	$ 38,767
EBITDA	$ 3,746	$ 18,580	$ 5,942	$ 43,207	$ 16,949	$ 63,945

Our fuel marketing companies generate large amounts of revenue and corresponding expense related to buying and selling energy commodities. Fuel marketing is extremely competitive, and margins are typically very small.

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001. The decrease in revenues is attributed to a substantial decline in commodity prices offset by a 24 percent increase in natural gas average daily volume marketed and a 56 percent increase in crude oil average daily volume marketed. Net income decreased 79 percent due to a substantial decline in commodity prices and margins. Unusual energy marketing conditions existed in the second quarter of 2001 stemming primarily from gas and electricity shortages in the West. Average spot gas prices in the West Coast region were approximately $9 per MMBtu in the second quarter of 2001 compared to $3 in the second quarter of 2002. As a result of changing commodity prices, net income was impacted by unrealized gains recognized through mark-to-market accounting treatment. Unrealized pre-tax mark-to-market gains/(losses) for the three month periods ended June 30, 2002 and 2001 were $1.3 million and $(1.2) million, respectively, resulting in a quarter over quarter net income increase of $1.5 million.

In addition, during the second quarter of 2002 we decided to discontinue operations in our coal marketing business due primarily to challenges encountered in marketing our Wyodak coal from the Powder River Basin of Wyoming to midwestern and eastern coal markets. We sold the non-strategic assets effective August 1, 2002. Net income from discontinued operations was ($0.9) million or ($0.03) per share for the three months ended June 30, 2002 compared to $0.3 million or $0.01 per share for the same period of the prior year. Prior year results of operations have been restated to reflect the discontinued operations and the coal marketing business is no longer reflected in the fuel marketing segment.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001. Revenues and net income decreased primarily due to a substantial decline in commodity prices and margins received, offset by an 11 percent increase in natural gas average daily volumes marketed and a 37 percent increase in crude oil average daily volumes marketed. Unusual energy marketing conditions existed in the first six months of 2001 stemming primarily from gas and electricity shortages in the West. Average spot gas prices in the West Coast region were approximately $11 per MMBtu in the first six months of 2001 compared to $3 in the first six months of 2002.

Income (loss) from discontinued operations were ($2.6) million or ($0.09) per share for the six months ended June 30, 2002 compared to $1.0 million or $0.04 per share for the same period of the prior year.

Twelve Months Ended June 30, 2002 Compared to Twelve Months Ended June 30, 2001. Revenues and net income decreased 45 percent and 69 percent, respectively, primarily due to a substantial decrease in margins received and a decline in commodity prices, partially offset by a 16 percent increase in the daily volumes of natural gas marketed. Unusual energy marketing conditions existed for a substantial part of the twelve-month period ended June 30, 2001, stemming primarily from gas and electricity shortages in the West. As a result of changing commodity prices, net income was impacted by unrealized losses recognized through mark-to-market accounting treatment. Unrealized pre-tax mark-to-market gains for the twelve month periods ended June 30, 2002 and 2001 were $2.0 million and $2.6 million, respectively, resulting in a year over year net income decrease of $0.4 million.

Net loss from discontinued operations was ($3.1) million or ($0.11) per share for the twelve months ended June 30, 2002 compared to income from discontinued operations of $1.4 million or $0.06 per share for the same period of the prior year. Prior year numbers have been restated to reflect the discontinued operations.

Power Generation

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
	(in thousands)					
Revenue	$39,099	$24,975	$71,182	$43,020	$122,456	$82,522
Operating income	$15,419	$12,024	$30,700	$17,565	$ 40,591	$37,835
Net income (loss)	$ 4,174	$ 3,687	$ 9,847	$ 2,582	$ 8,841	$ 5,694
EBITDA	$20,840	$15,176	$42,002	$22,344	$ 64,021	$39,997

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001. Revenue, operating income and net income increased 57 percent, 28 percent and 13 percent, respectively, for the three-month period ended June 30, 2002 compared to the same period in 2001 and is attributed to additional generating capacity. As of June 30, 2002, we had 646 megawatts of independent power capacity in service compared to 327 megawatts at June 30, 2001.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001. Revenue, operating income and net income increased substantially for the six-month period ended June 30, 2002 compared to the same period in 2001 and is attributed to additional generating capacity. As of June 30, 2002, we had 646 megawatts of independent power capacity in service compared to 327 megawatts at June 30, 2001.

The increase in net income for the six month period ended June 30, 2002 was also benefited by a $1.9 million after-tax benefit relating to the collection of receivables previously reserved for in the prior period for exposure to the California market and a $0.9 million after-tax adjustment for negative goodwill to reflect the impact of a change in accounting for goodwill in accordance with the adoption of Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS 142) effective January 1, 2002.

Twelve Months Ended June 30, 2002 Compared to Twelve Months Ended June 30, 2001. Revenues increased 48 percent and net income increased 55 percent for the twelve months ended June 30, 2002, compared to the same period of the prior year, due to additional generating capacity and the recording of certain non-recurring items. As of June 30, 2002, we had 646 megawatts of independent power capacity in service with an additional 364 megawatts under construction (including a 90 MW plant under a lease arrangement).

Non-recurring items that affected net income include: a $1.9 million after-tax benefit for the twelve month period ended June 30, 2002, relating to the collection of receivables reserved for in the prior period for exposure to the California market, a $0.9 million after-tax benefit for negative goodwill recorded in the twelve month period ended June 30, 2002, to reflect the impact of a change in accounting for goodwill in accordance with the adoption of SFAS 142, and a $4.4 million after-tax charge recorded in the twelve month period ended June 30, 2002, related to our exposure to Enron.

Oil and Gas

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
	(in thousands)					
Revenue	$6,866	$9,275	$12,955	$17,857	$28,505	$29,951
Operating income	$1,765	$4,496	$ 2,783	$ 8,893	$ 8,759	$13,747
Net income	$1,283	$2,963	$ 2,161	$ 5,919	$ 6,439	$ 8,783
EBITDA	$3,847	$6,478	$ 6,882	$12,605	$16,986	$20,079

The following is a summary of our estimated economically recoverable oil and gas reserves at June 30, 2002 measured using constant product prices at the end of the respective period. Estimates of economically recoverable reserves are based on a number of variables, which may differ from actual results.

	2002	2001
Barrels of oil (in millions)	4.6	4.5
Bcf of natural gas	23.2	25.6
Total in Bcf equivalents	50.5	52.6

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001. Revenue and net income of the oil and gas production business segment decreased 26 percent and 57 percent, respectively for the three month period ended June 30, 2002, compared to the same period in 2001 due to a 42 percent decrease in the average price received partially offset by a 16 percent increase in production volumes.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001. Revenue and net income of the oil and gas production business segment decreased 27 percent and 63 percent respectively, for the six month period ended June 30, 2002, compared to the same period in 2001 due to a 44 percent decrease in the average price received partially offset by a 20 percent increase in production volumes.

Twelve Months Ended June 30, 2002 Compared to Twelve Months Ended June 30, 2001. Revenue and net income decreased 5 percent and 27 percent respectively for the twelve month period ended June 30, 2002, compared to the same period in 2001 due to a 28 percent decrease in the average price received partially offset by a 29 percent increase in production volumes.

Mining

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
	(in thousands)					
Revenue	$6,881	$7,881	$15,083	$16,144	$30,738	$32,761
Operating income	$2,054	$2,160	$ 4,434	$ 4,834	$ 6,186	$ 8,424
Net income	$2,494	$2,307	$ 4,829	$ 4,623	$11,798	$ 7,714
EBITDA	$3,926	$3,280	$ 7,571	$ 6,861	$18,985	$11,641

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001. Revenue from our mining segment decreased 13 percent and net income increased 8 percent for the three-month period ended June 30, 2002, compared to the same period in 2001. A 9 percent increase in tons of coal sold was offset by lower prices received.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001. Revenue from our mining segment decreased 7 percent and net income increased 4 percent for the six-month period ended June 30, 2002, compared to the same period in 2001. A 16 percent increase in tons of coal sold was offset by lower prices received.

Twelve Months Ended June 30, 2002 Compared to Twelve Months Ended June 30, 2001. Revenue decreased 6 percent for the twelve month period ended June 30, 2002, compared to the same period in the prior year due to a 15 percent increase in tons of coal sold, partially offset by lower prices received.

Net income increased $4.1 million primarily as a result of a coal contract settlement, a gain on the sale of mining equipment and the increase in tons of coal sold. Tons of coal sold increased primarily due to the commencement of sales through our train load-out facility.

In 2001, we reached a settlement of ongoing litigation with PacifiCorp concerning rights and obligations under a coal supply agreement under which PacifiCorp purchased coal from our coal mine to meet the coal requirements of the Wyodak Power Plant. As a result of this settlement, we recognized $5.6 million pre-tax, non-operating income in the twelve month period ended June 30, 2002. In addition, we sold a conveyor system which resulted in a $2.6 million pre-tax gain.

Electric Utility Group

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
	(in thousands)					
Revenue	$38,303	$61,601	$75,494	$132,180	$156,524	$236,291
Operating expenses	24,950	32,291	47,814	74,206	102,711	136,733
Operating income	$13,353	$29,310	$27,680	$ 57,974	$ 53,813	$ 99,558
Net income	$ 6,792	$16,784	$14,614	$ 34,124	$ 25,730	$ 56,943
EBITDA	$17,845	$33,337	$36,471	$ 66,506	$ 66,155	$115,405

The following table provides certain operating statistics:

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
Firm (system) sales - MWh	462,000	464,000	968,000	990,000	1,990,000	2,005,000
Off-system sales - MWh	210,000	293,000	371,000	550,000	787,000	1,006,000

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001. Revenue, operating expenses and net income decreased 38 percent, 23 percent and 60 percent, respectively for the three month period ended June 30, 2002 compared to the same period in the prior year primarily due to a 28 percent decrease in off-system electric megawatt-hour sales and a 68 percent decrease in the average price per megawatt-hour sold off-system. Firm residential and contracted electricity sales increased, but were offset by a decline in industrial sales due to the closing of the Homestake Gold Mine at year-end 2001. Revenue declines were partially offset by lower fuel and purchased power costs.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001. Revenue, operating expenses and net income decreased 43 percent, 36 percent and 57 percent, respectively for the six month period ended June 30, 2002 compared to the same period in the prior year primarily due to a 33 percent decrease in off-system electric megawatt-hour sales and a 75 percent decrease in the average price per megawatt-hour sold off-system. Firm residential and contracted electricity sales increased, but were offset by a decline in industrial sales due to the closing of the Homestake Gold Mine at year-end 2001. Revenue declines were partially offset by lower fuel and purchased power costs.

Twelve Months Ended June 30, 2002 Compared to Twelve Months Ended June 30, 2001. Revenue, operating expenses and net income decreased 34 percent, 25 percent and 55 percent, respectively for the twelve month period ended June 30, 2002, compared to the same period in the prior year primarily due to a 68 percent decrease in the average price per megawatt-hour sold off-system and a 22 percent decrease in off-system electric megawatt-hour sales.

The average price received for off-system sales for the twelve-month period ended June 30, 2002, was approximately $35 per megawatt-hour compared to $108 per megawatt-hour for the same period in the prior year.

Communications Group

	Three Months Ended June 30		Six Months Ended June 30		Twelve Months Ended June 30	
	2002	2001	2002	2001	2002	2001
			(in thousands)			
Revenue-external*	$ 7,752	$ 4,582	$14,933	$ 8,508	$ 26,683	$ 14,392
Revenue-intersegment*	465	1,117	830	2,217	2,862	3,987
Operating expenses	10,412	8,499	20,433	17,296	40,894	33,069
Operating loss	$(2,195)	$(2,800)	$(4,670)	$ (6,571)	$(11,349)	$(14,690)
Net loss	$(2,049)	$(2,792)	$(4,276)	$ (6,682)	$ (9,894)	$(14,495)
EBITDA	$ 957	$ (337)	$ 1,471	$ (1,773)	$ 102	$ (6,039)

* External revenue is revenue from our broadband communications business. Intersegment revenue is primarily revenue from our information services company derived from providing services to our other business segments.

	June 30		March 31		December 31	
	2002	2001	2002	2001	2001	2000
Business customers	2,970	1,440	2,600	980	2,250	650
Residential customers	19,450	12,000	17,550	10,060	15,660	8,370

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001. The communications business group reported EBITDA positive results in the second quarter of 2002. The net loss for the three month period ended June 30, 2002 was $(2.0) million, compared to $(2.8) million in 2001. The performance improvement is due largely to a 67 percent increase in revenue as a result of a larger customer base, partially offset by increased costs of sales and administrative expenses.

The total number of customers exceeded 22,400 at the end of June 2002 - an 11 percent and 25 percent increase over the customer base at March 31, 2002 and December 31, 2001, respectively, and a 67 percent increase compared to June 30, 2001.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001. The communications business group reported EBITDA positive results in the first six months of 2002. The net loss for the six month period ended June 30, 2002 was $(4.3) million, compared to $(6.7) million in 2001. The performance improvement is due largely to a 74 percent increase in revenue as a result of a larger customer base, partially offset by increased costs of sales and administrative expenses.

The total number of customers exceeded 22,400 at the end of June 2002 - an 11 percent and 25 percent increase over the customer base at March 31, 2002 and December 31, 2001, respectively, and a 67 percent increase compared to June 30, 2001.

Twelve Months Ended June 30, 2002 Compared to Twelve Months Ended June 30, 2001. The net loss for the twelve month period ended June 30, 2002 was $(9.9) million, compared to $(14.5) million for the same period in the prior year. The performance improvement was the result of a 67 percent increase in our customer base offset by increased cost of sales, administrative expenses, reserves for inventory and carrier billings and increased interest expense.

We expect our communications group will sustain approximately $6.5 million in net losses in calendar year 2002, with annual losses decreasing thereafter and profitability expected by 2004. The recovery of capital investment and future profitability are dependent primarily on our ability to attract new customers. If we are unable to attract additional customers or technological advances make our network obsolete, we could have a material write-down of assets.

Earnings Guidance

We reaffirm confidence in our ongoing business strategy, which seeks long-term growth through the expansion of integrated, balanced and diverse competitive energy operations supplemented by the strength and stability of our electric utility and improving results from our communication business. The energy industry has encountered challenging market conditions this year, including low and volatile prices for natural gas and wholesale power. We previously indicated a long-term earnings per share growth target in a range of 10 to 15 percent per year based on historical performance. Until market conditions improve, we expect annual earnings per share percentage growth to be in the 8 to 10 percent range. We also expect recurring earnings for 2002 to be in the range of $2.25 to $2.30 per share. We recognize that sustained growth requires capital deployment to continue expanding our integrated energy operations. We strongly believe that we are strategically positioned to take advantage of opportunities to acquire and develop energy assets consistent with our investment criteria.

Critical Accounting Policies

Goodwill and Other Intangible Assets

As required, on January 1, 2002 we adopted the provisions of Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets" (SFAS 142). Under SFAS 142, goodwill and intangible assets with indefinite lives are no longer amortized but the carrying values are reviewed annually (or more frequently if impairment indicators arise) for impairment. Intangible assets with a defined life will continue to be amortized over their useful lives (but with no maximum). Initial adoption of SFAS 142 did not have a material impact on our financial position or results of operations. Adoption of SFAS 142 provisions for non-amortization of goodwill and indefinite lived intangibles will impact our future earnings results. Results for the three, six and twelve months ended June 30, 2002 were approximately $0.5 million, $0.9 million and $1.6 million, or 2 cents per share, 3 cents per share and 6 cents per share, higher than the comparable periods in 2001 due to non-amortization of goodwill.

Other than the above, there have been no material changes in our critical accounting policies from those reported in our 2001 Annual Report on Form 10-K filed with the Securities Exchange Commission. For more information on our critical accounting policies, see Part II, Item 7 in our 2001 Annual Report on Form 10-K.

Liquidity and Capital Resources

Cash Flow Activities

During the six month period ended June 30, 2002, we generated sufficient cash flow from operations to meet our operating needs, to pay dividends on common and preferred stock, to pay long-term debt maturities and to fund a portion of our property additions. We continue to fund property and investment additions primarily related to construction of additional electric generation facilities for our integrated energy business group through a combination of operating cash flow, increased short-term debt and long-term non-recourse project financing.

Cash flows from operations decreased $59.7 million for the six-month period ended June 30, 2002 compared to the same period in the prior year primarily due to the decrease in net income and cash provided by changes in working capital.

On March 8, 2002, we acquired an additional 67 percent interest in Millennium Pipeline Company, L.P., which owns and operates a 200-mile pipeline and an additional ownership interest in Millennium Terminal Company, L.P., which has 1.1 million barrels of crude oil storage connected to the Millennium Pipeline at the Oil Tanking terminal in Beaumont, Texas. Total cost of the acquisition was $11.0 million and was funded through borrowings under short-term revolving credit facilities.

On March 15, 2002, we acquired an additional 30 percent interest in the Harbor Cogeneration Facility, a 98-megawatt gas-fired plant located in Wilmington, California for $25.7 million. This acquisition was also funded through borrowings under short-term revolving credit facilities.

On March 15, 2002, we closed on $135 million of senior secured financing for the Arapahoe and Valmont facilities, 210 megawatts in service and under construction in the Denver, Colorado area. Proceeds from this financing were used to refinance $53.8 million of an existing seven-year secured term project-level facility, pay down approximately $50.0 million of short-term credit facility borrowings with the remainder to be used for future project construction costs.

During the first quarter of 2002, we completed a $50 million bridge credit agreement. The credit agreement supplements our revolving credit facilities and has the same terms as those facilities with an original expiration date of June 30, 2002. During the second quarter of 2002, the term was extended to August 28, 2002.

On June 18, 2002, we closed on a $75 million bridge credit agreement. As of June 30, 2002, there were no borrowings outstanding under this bridge credit agreement. This credit agreement bridged the issuance of $75 million of Black Hills Power First Mortgage bonds, which we issued on August 13, 2002. The termination date of the bridge credit agreement was August 13, 2002, the date on which the First Mortgage Bonds were issued.

Dividends

Dividends paid on our common stock totaled $0.29 per share in each of the first and second quarters of 2002. This reflects a 3.6 percent increase, as approved by our board of directors in January 2002, from the prior periods. The determination of the amount of future cash dividends, if any, to be declared and paid will depend upon, among other things, our financial condition, funds from operations, the level of our capital expenditures, restrictions under our credit facilities and our future business prospects.

Short-Term Liquidity and Financing Transactions

Our principal sources of short-term liquidity are our revolving bank facilities and cash provided by operations. As of June 30, 2002 we had approximately $54 million of cash and $525 million of bank facilities. Approximately $23 million of the cash balance at June 30, 2002 was restricted by subsidiary debt agreements in regards to the ability to dividend the cash to the parent company. The bank facilities consisted of a $50 million bridge facility due August 28, 2002, a $75 million bridge facility, which expired when our Electric Utility issued the First Mortgage Bonds described above, a $200 million facility due August 27, 2002 and a $200 million facility due August 27, 2004. These bank facilities can be used to fund our working capital needs, for general corporate purposes and to provide liquidity for a commercial paper program if implemented. At June 30, 2002, we had $406 million of bank borrowings outstanding under these facilities. The corresponding amount outstanding at July 31, 2002 was $421 million. After inclusion of applicable letters of credit, the remaining borrowing capacity under the bank facilities was $79.6 million and $54.6 million at June 30, 2002 and July 31, 2002, respectively.

The above bank facilities include covenants that are common in such arrangements. Such covenants include a consolidated net worth in an amount of not less than the sum of $375 million and 50 percent of the aggregate consolidated net income beginning June 30, 2001; a recourse leverage ratio not to exceed 0.65 to 1.00; and an interest coverage ratio of not less than 3.00 to 1.00. If these covenants are violated, it would be considered an event of default entitling the lender to terminate the remaining commitment and accelerate all principal and interest outstanding to become immediately due. In addition, certain of our interest rate swap agreements include cross-default provisions. These provisions would allow the counterparty the right to terminate the swap agreement and liquidate at a prevailing market rate, in the event of default.

Some of the facilities previously had a covenant whereby we were required to maintain a credit rating of at least "BBB-" from Standard & Poor's or "Baa3" from Moody's Investor Service. The facilities that contained the rating triggers were amended during the second quarter of 2002 to remove default provisions pertaining to our credit rating status.

Our consolidated net worth was $529.1 million at June 30, 2002. The long-term debt component of our capital structure at June 30, 2002 was 47 percent and our total debt leverage (long-term debt and short-term debt) was 63 percent.

In addition, Enserco Energy, Inc., our gas marketing unit, had a $75 million uncommitted, discretionary line of credit to provide support for the purchase of natural gas. We provided no guarantee to the lender under this facility. At June 30, 2002, there were outstanding letters of credit issued under the facility of $39.7 million with no borrowing balances on the facility. Similarly, Black Hills Energy Resources, Inc., our oil marketing unit, had a $25 million uncommitted, discretionary credit facility. This line of credit provided credit support for the purchases of crude oil by Black Hills Energy Resources. We provided no guarantee to the lender under this facility. At June 30, 2002, Black Hills Energy Resources had letters of credit outstanding of $22.6 million and no balance outstanding on its overdraft line.

On June 28, 2002, Enserco Energy closed on a $135 million uncommitted, discretionary credit facility, which became effective July 1, 2002 and expires June 27, 2003. This facility replaced the $75 million Enserco Energy facility. We provide no guarantee to the lender under this facility.

We are currently seeking long-term project-level non-recourse financing in the range of $160 million for the expansion at our Las Vegas Project, a 277 megawatt gas-fired generation complex located in North Las Vegas, Nevada, prior to August 27, 2002. Total project costs are estimated to be $330 million of which approximately $289 million was expended as of June 30, 2002 and was funded with short-term credit facility borrowings. In addition to the $75 million First Mortgage Bonds that our Electric Utility issued on August 13, 2002, we anticipate renewing our $200 million credit facility that expires on August 27, 2002. If we are successful in completing the Las Vegas project financing and renewing our credit facility, our liquidity position will substantially improve. Although we believe these financings will be completed by August 27, 2002, we can make no guarantee these financings will occur within the planned time frame, on reasonable terms or at all. If we are not successful in obtaining either the Las Vegas Project financing or renewing the $200 million credit facility by August 27, 2002, we may have a deficiency in our liquidity. In that event, we expect that we would remedy such a deficiency by seeking other forms of financing, including seeking extensions on our short-term credit facilities.

Our ability to obtain additional financing will depend upon a number of factors, including our future performance and financial results and capital market conditions. We cannot be sure that we will be able to raise additional capital on reasonable terms or at all.

There have been no other material changes in our forecasted changes in liquidity and capital requirements from those reported in Item 7 of our 2001 Annual Report on Form 10-K filed with the Securities Exchange Commission.

RISK FACTORS

Risks Relating to Our Business

We have substantial indebtedness and will require significant additional amounts of debt and equity capital to grow our businesses and service our indebtedness. Our future access to these funds is not certain, and our inability to access funds in the future could adversely affect our liquidity.

As of June 30, 2002, we had $918.6 million of short- and long-term debt. Our substantial debt presents the risk that we might not generate sufficient cash to maintain our credit facilities or service our indebtedness. In addition, our leveraged capital structure could limit our ability to finance the acquisition and development of additional projects, to compete effectively, to operate successfully under adverse economic conditions and to fully implement our strategy. The terms of our debt may also restrict our flexibility in operating our projects.

In order to access capital on a substantially non-recourse basis in the future, we may have to make larger equity investments in, or provide more financial support for, our project subsidiaries. We also may not be successful in structuring future financing for our projects on a substantially non-recourse basis.

The State of California's efforts to void or reform its long-term power purchase contracts with various suppliers may adversely affect our contracts with these suppliers and our independent power subsidiary's results of operations.

Our independent power subsidiary, Black Hills Energy Capital, Inc., indirectly owns our Las Vegas Cogeneration II plant, which is currently under construction and which we refer to as LV Cogen II. LV Cogen II is party to a 15-year tolling agreement with Allegheny Energy Supply Company, LLC, or AESC, under which AESC will deliver fuel to the facility and LV Cogen II will sell all of the facility's capacity, and all associated energy and ancillary services produced at the facility, to AESC.

The California Public Utilities Commission filed a complaint with the Federal Energy Regulatory Commission, or FERC, in February 2002, seeking to void or, in the alternative, reform a number of long-term power purchase contracts entered into between the State of California/Department of Water Resources and several suppliers in 2001. One of the suppliers named in the complaint was AESC. If AESC's contract with the State of California/Department of Water Resources is voided or reformed, AESC may seek to alter or cancel its contract with LV Cogen II. Any such action by AESC, if successful, could adversely affect our independent power subsidiary's results of operations.

Counterparty Credit Risk

We perform ongoing credit evaluations of our customers and adjust credit limits based upon payment history and the customer's current creditworthiness, as determined by our review of their current credit information. We continuously monitor collections and payments from our customers and maintain a provision for estimated credit losses based upon historical experience and any specific customer collection issue that we have identified. While most credit losses have historically been within our expectations and provisions established, we cannot guarantee that we will continue to experience the same credit loss rates that we have in the past or that an investment grade counterparty will not default, as was the case with Enron in 2001.

Our agreements with counterparties that have recently experienced downgrades in their credit ratings expose us to the risk of counterparty default, which could adversely affect our cash flow and profitability.

Our independent power subsidiary, Black Hills Energy Capital, indirectly owns a 50% interest in the Las Vegas Cogeneration I plant, which is a 53-megawatt gas-fired power plant located in North Las Vegas, Nevada. Under accounting principles generally accepted in the United States, we consolidate 100% of the entity. Most of the power from that facility is sold under a long-term contract with Nevada Power Company, which expires in 2024. The credit ratings of Nevada Power Company and its parent holding company, Sierra Pacific Resources, have both been recently downgraded to non-investment grade status. Our independent power subsidiary could experience lost revenues and increased expenses if Nevada Power Company is unable to perform on its obligations under the power contract, either as a result of a deterioration of its creditworthiness or for any other reason.

Our rate freeze agreement with the South Dakota Public Utilities Commission, which prevents us, absent extraordinary circumstances, from passing on to our South Dakota retail customers cost increases we may incur during the rate freeze period, could decrease our operating margins.

Our rate freeze agreement with the South Dakota Public Utilities Commission provides that, until January 1, 2005, we may not apply to the Commission for any increase in rates, except upon the occurrence of various extraordinary events.

Our utility's historically stable returns could be threatened by plant outages, machinery failure, increases in purchased power costs over which we have no control, acts of nature or other unexpected events that could cause our operating costs to increase and our operating margins to decline. Moreover, in the event of unexpected plant outages or machinery failures, we may be required to purchase replacement power in wholesale power markets at prices, which exceed the rates we are permitted to charge our retail customers.

Because wholesale power, fuel prices and other costs are subject to volatility, our revenues and expenses may fluctuate.

A substantial portion of our growth in net income in recent years is attributable to increasing wholesale sales into a robust market. The prices of energy products in the wholesale power markets have declined significantly since the first half of 2001. Power prices are influenced by many factors outside our control, including fuel prices, transmission constraints, supply and demand, weather, economic conditions, and the rules, regulations and actions of the system operators in those markets. Moreover, unlike most other commodities, electricity cannot be stored and therefore must be produced concurrently with its use. As a result, wholesale power markets are subject to significant price fluctuations over relatively short periods of time and can be unpredictable.

Increasing competition in our businesses may adversely affect our ability to make investments or acquisitions on attractive terms.

We face increasing competition in each of our businesses. In particular, the independent power industry is characterized by numerous strong and capable competitors, some of which have more extensive experience in the operation, acquisition and development of power generation facilities, larger staffs or greater financial resources than we do. Many of our competitors are also seeking favorable power generation opportunities. This competition may adversely affect our ability to make investments or acquisitions on attractive terms.

Our broadband communications business is subject to significant competition for its services and to rapid technological change.

Although our communications unit has achieved rapid penetration of our existing market, we face strong competition for our services from the incumbent local exchange carrier as well as from long distance providers, Internet service providers, the incumbent cable television provider and others.

The communications industry is subject to rapid and significant changes in technology. There can be no assurance that future technological developments will not have a material adverse effect on our competitive position.

Our ability to recover our capital investment and achieve operating profits is dependent on our ability to attract additional customers and is subject to the risk that technological advances may render our network obsolete. No assurance can be given that we will be successful in meeting our goals. If we determine that we will be unable to recover our investment, we would be required to take a non-cash charge to earnings in an amount that could be material in order to write down a portion of our investment in our broadband communications business.

Construction, expansion, refurbishment and operation of power generation facilities involve significant risks that we cannot always cover by insurance or contractual protections which could lead to lost revenues or increased expenses.

The construction, expansion and refurbishment of power generation and transmission and resource recovery facilities involve many risks, including: the inability to obtain required governmental permits and approvals; the unavailability of equipment; supply interruptions; work stoppages; labor disputes; social unrest; weather interferences; unforeseen engineering, environmental and geological problems and unanticipated cost overruns.

The ongoing operation of our facilities involves all of the risks described above, in addition to risks relating to the breakdown or failure of equipment or processes and performance below expected levels of output or efficiency. New plants may employ recently developed and technologically complex equipment, especially in the case of newer environmental emission control technology. Any of these risks could cause us to operate below expected capacity levels, which in turn could result in lost revenues, increased expenses, higher maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover lost revenues, increased expenses or liquidated damages payments.

Estimates of our proved reserves may materially change due to numerous uncertainties inherent in estimating oil and natural gas reserves.

There are many uncertainties inherent in estimating quantities of proved reserves and their values. The process of estimating oil and natural gas reserves requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretations and judgement, and the assumptions used regarding quantities of recoverable oil and gas reserves and prices for oil and natural gas. Actual prices, production, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves will vary from those assumed in our estimates, and these variances may be significant. Any significant variance from the assumptions used could result in the actual quantity of our reserves and future net cash flow being materially different from the estimates in our reported reserves. In addition, results of drilling, testing and production and changes in oil and natural gas prices after the date of the estimate may result in substantial upward or downward revisions.

Potential Claim Related to Forest Fire in South Dakota

In June 2002, a forest fire damaged approximately 10,800 acres of private and governmental land located near Deadwood and Lead, South Dakota. The fire destroyed approximately 20 structures (seven houses and 13 outbuildings) and caused the evacuation of the cities of Lead and Deadwood for approximately 48 hours.

The cause of the fire was investigated by the State of South Dakota. Sagging power lines owned by us were implicated as the cause. We have initiated our own investigation into the cause of the fire, including the hiring of expert fire investigators and that investigation is continuing.

Although we have been put on notice of potential claims, no civil action or regulatory proceeding has been initiated against us at this time. If, however, it is determined that sagging power lines owned by us were the cause of the fire and that we were negligent in the maintenance of those power lines, we could be liable for resultant damages. Although we cannot predict the outcome of either our investigation or of potential claims, management believes that any such claims will not have a material adverse effect on our financial condition or results of operations.

Risks Relating to Our Industry

Our business is subject to substantial governmental regulation and permitting requirements as well as on-site environmental liabilities we assumed when we acquired some of our facilities. We may be adversely affected by any future inability to comply with existing or future regulations or requirements or the potentially high cost of maintaining the compliance of our facilities.

In General. Our business is subject to extensive energy, environmental and other laws and regulations of federal, state and local authorities. We generally are required to obtain and comply with a wide variety of licenses, permits and other approvals in order to operate our facilities. In the course of complying with these requirements, we may incur significant additional costs. If we fail to comply with these requirements, we could be subject to civil or criminal liability and the imposition of liens or fines. In addition, existing regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities, and future changes in laws and regulation may have a detrimental effect on our business.

Environmental Regulation. In acquiring some of our facilities, we assumed on-site liabilities associated with the environmental condition of those facilities, regardless of when such liabilities arose and whether known or unknown, and in some cases agreed to indemnify the former owners of those facilities for on-site environmental liabilities. We strive at all times to be in compliance with all applicable environmental laws and regulations. However, steps to bring our facilities into compliance, if necessary, could be expensive, and thus could adversely affect our financial condition. Furthermore, with the continuing trends toward stricter standards, greater regulation, more extensive permitting requirements and an increase in the assets we operate, we expect our environmental expenditures to be substantial in the future.

Ongoing changes in the United States utility industry, such as state and federal regulatory changes, a potential increase in the number of our competitors or the imposition of price limitations to address market volatility, could adversely affect our profitability.

The United States electric utility industry is currently experiencing increasing competitive pressures as a result of consumer demands, technological advances, deregulation, greater availability of natural gas-fired generation and other factors. The FERC has implemented and continues to propose regulatory changes to increase access to the nationwide transmission grid by utility and non-utility purchasers and sellers of electricity. In addition, a number of states have implemented or are considering or currently implementing methods to introduce and promote retail competition. Industry deregulation in some states has led to the disaggregation of some vertically integrated utilities into separate generation, transmission and distribution businesses, and deregulation initiatives in a number of states may encourage further disaggregation. As a result, significant additional competitors could become active in the generation, transmission and distribution segments of our industry.

Proposals have been introduced in Congress to repeal the Public Utility Holding Company Act of 1935, or PUHCA, and the FERC has publicly indicated support for the PUHCA repeal effort. To the extent competitive pressures increase and the pricing and sale of electricity assume more characteristics of a commodity business, the economics of domestic independent power generation projects may come under increasing pressure.

In addition, the independent system operators who oversee most of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address some of the volatility in these markets. These types of price limitations and other mechanisms may adversely affect the profitability of our generation facilities that sell energy into the wholesale power markets. Given the extreme volatility and lack of meaningful long-term price history in some of these markets and the imposition of price limitations by independent system operators, we may not be able to operate profitably in all wholesale power markets.

NEW ACCOUNTING PRONOUNCEMENTS

During June 2002, the Emerging Issues Task Force (EITF) reached a consensus on Issues 1 and 3 of EITF Issue No. 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," and No. 00-17, "Measuring the Fair Value of Energy-Related Contracts in Applying Issue No. 98-10."

Under EITF 02-3, Issue 1 of the consensus requires mark-to-market gains and losses on energy trading contracts to be shown net on the income statement whether or not physically settled in financial statements issued for periods ending after July 15, 2002. Issue 3 requires entities involved in energy trading activities to include certain additional disclosures in financial statements issued for fiscal years ending after July 15, 2002. EITF 02-3 also requires that all comparative financial statements be reclassified to conform to EITF 02-3. Although EITF 02-3 will require our mark-to-market gains and losses on energy trading contracts to be shown net on the income statement, it is not expected to impact our net income, stockholders' equity or cash flows. We will adopt the guidance of Issue 1 during the third quarter, but have not yet quantified the financial statement effect from this adoption.

Other than the above, and the new pronouncements reported in our 2001 Annual Report on Form 10-K filed with the Securities Exchange Commission, there have been no new accounting pronouncements issued that when implemented would require us to either retroactively restate prior period financial statements or record a cumulative catch-up adjustment.

Forward Looking Statements

Some of the statements in this Form 10-Q include "forward-looking statements" as defined by the Securities and Exchange Commission, or SEC. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Form 10-Q that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These forward-looking statements are based on assumptions, which we believe are reasonable based on current expectations and projections about future events and industry conditions and trends affecting our business. However, whether actual results and developments will conform to our expectations and predictions is subject to a number of risks and uncertainties that could cause actual results to differ materially from those contained in the forward-looking statements, including, among other things: (1) unanticipated developments in the western power markets, including unanticipated governmental intervention, deterioration in the financial condition of counterparties, default on amounts due from counterparties, adverse changes in current or future litigation, adverse changes in the tariffs of the California Independent System Operator, market disruption and adverse changes in energy and commodity supply, volume and pricing and interest rates; (2) prevailing governmental policies and regulatory actions with respect to allowed rates of return, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of purchased power and other capital investments, and present or prospective wholesale and retail competition; (3) the State of California's efforts to reform its long-term power purchase contracts; (4) changes in and compliance with environmental and safety laws and policies; (5) weather conditions; (6) population growth and demographic patterns; (7) competition for retail and wholesale customers; (8) pricing and transportation of commodities; (9) market demand, including structural market changes; (10) changes in tax rates or policies or in rates of inflation; (11) changes in project costs; (12) unanticipated changes in operating expenses or capital expenditures; (13) capital market conditions; (14) technological advances by competitors; (15) competition for new energy development opportunities; (16) legal and administrative proceedings that influence our business and profitability; (17) the effects on our business, including the availability of insurance, resulting from the terrorist actions on September 11, 2001, or any other terrorist actions or responses to such actions; (18) the effects on our business resulting from the financial difficulties of Enron and other energy companies, including their effects on liquidity in the trading and power industry, and their effects on the capital markets views of the energy or trading industry, and our ability to access the capital markets on the same favorable terms as in the past; (19) the effects on our business in connection with a lowering of our credit rating (or actions we may take in response to changing credit ratings criteria), including, increased collateral requirements to execute our business plan, demands for increased collateral by our current counterparties, refusal by our current or potential counterparties or customers to enter into transactions with us and our inability to obtain credit or capital in amounts or on terms favorable to us; (20) risk factors discussed in this Form 10-Q; and (21) other factors discussed from time to time in our filings with the SEC. New factors that could cause actual results to differ materially from those described in forward-looking statements emerge from time to time, and it is not possible for us to predict all such factors, or the extent to which any such factor or combination of factors may cause actual results to differ from those contained in any forward-looking statement. We assume no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events, or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes in market risk faced by the Company from those reported in the Company's 2001 Annual Report on Form 10-K filed with the Securities Exchange Commission. For more information on market risk, see Part II, Item 7 in the Company's 2001 Annual Report on Form 10-K, and Notes to Condensed Consolidated Financial Statements in this Form 10-Q.

Part II - Other Information

Item 1. Legal Proceedings

For information regarding legal proceedings, see Note 10 to the Company's 2001 Annual Report on Form 10-K and Note 12 in Item 1 of Part I of this Quarterly Report on Form 10-Q, which information from Note 12 is incorporated by reference into this item.

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

(a) The Annual Meeting of Shareholders was held on May 29, 2002.

(b) The following Directors were elected to serve until the Annual Meeting of Shareholders in 2005.

David S. Maney
Bruce B. Brundage
Kay S. Jorgensen

Other Directors whose term of office continues are:

David C. Ebertz
John R. Howard
Daniel P. Landguth
Adil M. Ameer
Everett E. Hoyt
Thomas J. Zeller

(c) Matters Voted Upon at the Meeting

1. Elected three Class II Directors to serve until the Annual Meeting of Shareholders in 2005.

David S. Maney	
Votes For	23,386,876
Votes Withheld	351,576
Bruce B. Brundage	
Votes For	23,375,621
Votes Withheld	362,831
Kay S. Jorgensen	
Votes For	23,355,775
Votes Withheld	382,677

2. Item 2, the ratification of the appointment of Arthur Andersen LLP to serve as Black Hills Corporation's independent public accountants in 2002 was withdrawn and not voted on at the Annual Meeting.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits -

Exhibit 99.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit 99.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b) Reports on Form 8-K

We have filed the following Reports on Form 8-K during the quarter ended June 30, 2002.

Form 8-K dated May 31, 2002.

Reported under item 4 the change in our independent public accountants from Arthur Andersen LLP to Deloitte & Touche LLP.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BLACK HILLS CORPORATION

/s/ Roxann R. Basham

Roxann R. Basham, Vice President - Controller
(Principal Accounting Officer)

/s/ Mark T. Thies

Mark T. Thies, Senior VP & CFO
(Principal Financial Officer)

Dated: August 14, 2002

EXHIBIT INDEX

Exhibit (99.1)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit (99.2)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 99.1

BLACK HILLS CORPORATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Black Hills Corporation (the "Company") on Form 10-Q for the period ending June 30, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Daniel P. Landguth, Chairman of the Board and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, 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 result of operations of the Company.

/s/ Daniel P. Landguth
- --
Daniel P. Landguth
Chairman of the Board and
Chief Executive Officer
August 14, 2002

Exhibit 99.2

BLACK HILLS CORPORATION

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Black Hills Corporation (the "Company") on Form 10-Q for the period ending June 30, 2002 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Mark T. Thies, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, 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 result of operations of the Company.

/s/ Mark T. Thies
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Mark T. Thies
Senior Vice President and
Chief Financial Officer
August 14, 2002