July 21, 2005

Mr. Jim Allegretto
Sr. Assistant Chief Accountant
United States Securities and Exchange Commission
100 F Street, NE
Washington, D.C. 20549-3651

Re: Black Hills Corporation
Form 10-K for the year ended December 31, 2004
Filed March 16, 2005
File No. 1-31303

Black Hills Power, Inc.
Form 10-K for the year ended December 31, 2004
Filed March 30, 2005
File No. 1-7978

Dear Mr. Allegretto:

The purpose of this letter is to respond to your comments as set forth in your letter of June 29, 2005. The headings used herein are the same as those set forth in your letter. For ease of reference, we have set forth your comment before each response.

In connection with our response to your comments, we acknowledge the following:

- the Company is responsible for the adequacy and accuracy of the disclosure in the filing;
- staff comments or changes to disclosure in response to staff comments do not foreclose the Commission from taking any action with respect to the filings; and
- the Company may not assert staff comments as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2004

General

Comment No. 1:

Where a comment below requests additional disclosures or other revisions to be made, please include them in your future filings including interim periods where applicable. In our interest to reduce the volume of comments, we have not addressed Black Hills Power, Inc. with a separate comment if applicable to their facts and circumstances. Please note that if you agree to a revision, we would also expect a concurrent change be made in the Black Hills Power, Inc. financial statements and related disclosures. Please confirm to us your agreement with this objective.

The Company agrees that any revisions it agrees to make in its future filings will also be provided in the future filings of Black Hills Power, Inc., if applicable to their facts and circumstances.

Items 7 and 7A Management's Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures About Market Risk

Oil and Gas, page 51

Comment No. 2:

We note that your lease operating expenses and depletion per Mcfe sold has changed substantially in the periods provided. Please expand to discuss the economic reasons that underlie these variances.

The following table is provided for reference in the following discussion:

	2002	2003	2004
E. Blanco LOE/Mcfe	N/A	$1.41	$1.15
All Other Properties LOE/Mcfe	$0.69	$0.75	$0.85
TOTAL LOE/Mcfe	$0.69	$0.95	$0.97
Total Depletion/Mcfe	$0.98	$0.83	$0.92

With the acquisition of Mallon Resources Corporation on March 10, 2003, Black Hills Exploration and Production (BHEP) acquired significant gathering, treating and compression facilities associated with the East Blanco field. The operating costs of these facilities are allocated to the East Blanco properties as LOE and represented $0.80 and $0.65 of East Blanco's LOE per Mcfe for 2003 and 2004, respectively. In addition, BHEP initiated efforts throughout 2003 and into 2004 to remediate properties that had been neglected prior to the acquisition. These activities contributed to East Blanco's total $1.41 and $1.15 LOE per Mcfe for 2003 and 2004, respectively. LOE per Mcfe in the East Blanco field in 2003 was $1.41 as compared to $0.75 for our other properties, resulting in an increase in the Company's overall average LOE per Mcfe.

The nominal $0.02 increase in LOE per Mcfe from 2003 to 2004 was attributable to increased activity in our Wyoming oil field, offset by a decline in LOE per Mcfe at East Blanco due to increases in production and the recovery of the fixed gathering, processing and compression costs over a larger pool of production.

The decrease in Depletion per Mcfe from 2002 to 2003 is also attributable to the Mallon acquisition. Most of this decrease is due to the fact that the reserves we recorded pursuant to the acquisition have a lower cost per Mcfe than our average cost in 2002, thus lowering our average depletion cost per Mcfe. The increase between 2003 and 2004 is a function of increases in average development costs per Mcfe as we develop the field.

We will provide more robust disclosure related to these activities, to the extent meaningful, in our future filings.

Electric Utility, page 53

Comment No. 3:

Your electric utility segment has a trend of decreasing operating and net income over the 3 year period. Your discussion should provide greater information on the reasons underlying such a trend. For example, we note rising purchased power costs, offset by decreased fuel costs, were responsible for much of the 2004 earnings decline. It is implied that rising natural gas prices made it more economical to purchase other fuel source power and cut back on your gas-fired generation. If this was the case, you may want to make it clearer in your discussion. If not the case, then expand to explain the business reasons for your increased purchased power costs versus lower fuel costs. Furthermore the reasons for each of the increasing components of utility operating expenses should be discussed and quantified.

In identifying the trending decrease in our utility segment's operating and net income over the 3 year period presented, the Company cites its disclosures on pages 20, 37, 40 and 53 of the 2004 Black Hills Corporation 10-K. On pages 20 and 40 we disclose our utility's rate freeze, which has been in place since 1995. This discloses that our revenues from our system sales are generally stable, as our service territory has historically had only nominal annual load growth. Our wholesale off-system sales are a significant factor in causing variability in our utility revenues. The related costs of these sales are a primary driver in the increased purchased power and fuel costs. While we believe we have disclosed our intent to attempt to capitalize on off-system sales opportunities, we also have included in our "Industry Overview" on page 37 our view of the power markets. On page 53 we provide our disclosure to describe and quantify our utility's increasing operating cost structure. While we have attempted to provide clarity into these items in our filings, we realize the discussion is not all in one place within the filing. In future filings, we will strive to provide additional clarity on these issues to the extent possible and centralize the discussion in the Managements' Discussion and Analysis.

In regard to the Staff's inquiry into fluctuations in purchased power and fuel costs, we believe the disclosure included on page 53 clarifies the economic decision to purchase power from the market rather than to run our gas-fired turbines.

Comment No. 4:

You indicate on page 13 that your customer base includes commercial, residential, contract wholesale, wholesale off-system, industrial, municipal, and other customers. Please provide volume data and revenue amounts segregated by components of your customer base.

			Revenue (in thousands)		
Customer Base	**2004**	**%**	**2003**	**%**	**2002**
Commercial	$46,791	-2%	$47,777	2%	$46,673
Residential	36,536	-3%	37,716	2%	37,111
Industrial	19,796	1%	19,589	-4%	20,407
Municipal Sales & Other	2,200	5%	2,102	2%	2,070
Contract Wholesale	22,720	6%	21,451	-20%	26,879
Wholesale Off-System	38,228	13%	33,743	53%	22,083
	$166,271	2%	$162,378	5%	$155,223

			Megawatt Hours		
Customer Base	**2004**	**%**	**2003**	**%**	**2002**
Commercial	627,326	-2%	641,779	3%	620,665
Residential	447,166	-3%	463,290	2%	454,201
Industrial	406,209	0%	404,341	-2%	413,930
Municipal Sales & Other	28,934	5%	27,426	2%	26,839
Contract Wholesale	614,700	5%	582,743	-23%	757,050
Wholesale Off-System	926,461	15%	805,946	20%	673,052
	3,050,796	4%	2,925,525	-1%	2,945,737

We will include the information provided above in future filings, along with an explanation of meaningful changes in volume and revenue derived from each component of our customer base.

Comment No. 5:

We note that you indicate degree days in 2004 are 9 percent below normal and 11 percent below the prior year. We assume you mean heating degree days. While such information is useful, we believe your disclosure could be enhanced by providing an analysis of the class of customers who are more sensitive to weather trends in tying the numerical change in degree days with the related volume change for such customers. To the extent your residential customer base does not use electric resistance to heat their homes; you may want to make this clear. In addition since your peak load occurs at approximately the same volume for summer versus winter, you may want to clarify whether you mean heating degree days or cooling degree days.

In future filings, we will enhance our disclosures to clarify meaningful impacts of weather trends on the different components of our utility customer base. This enhanced disclosure will include any necessary differentiation between heating and cooling degree days.

<u>Note 1. Business Description and Summary of Significant Accounting Policies</u>
<u>Material, Supplies and Fuel. page 86</u>

<u>Comment No. 6</u>:

Please tell us how you currently account for the stripping costs associated with your mining activities. To the extent that such costs are capitalized as a component of inventory, please tell us how often your inventory turns. Additionally, please tell us how the adoption of EITF 04-06 will impact your financial statements.

We currently account for stripping costs by recording a deferred asset. This asset is amortized into earnings as a cost of sales when coal is sold using a proportional performance ratio. This ratio is based on historical and forecasted stripping costs and the actual and estimated tons of coal uncovered, resulting in a stripping cost rate applied to each ton sold.

We have not capitalized stripping costs as a component of inventory as our mine does not stockpile an inventory of coal as it is extracted. Our mine's primary customers are mine-mouth power generation facilities owned by our regulated and non-regulated subsidiaries and PacifiCorp. As the coal is extracted it is placed on a conveyor belt that delivers the coal to these power plants. Although we don't inventory coal, it is useful to note that our mine typically operates with uncovered coal reserves equaling approximately 12 months of production.

The adoption of EITF 04-06 will result in the Company adjusting the methodology used in its ratio for developing its stripping cost rate. The new rate will be generated on an annual basis based on the stripping costs incurred for the period and the related tons of coal uncovered. Based on management's evaluation of EITF 04-06, we do not believe that its adoption will have a material impact on our consolidated financial statements.
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<u>Comment No. 7</u>:

Please disclose the aggregate transaction gain or loss recorded in your consolidated statements of income for the three years ended December 31, 2004. Please refer to paragraphs 15 and 30 of SFAS 52. Please explain your basis in GAAP, practice or promulgated, of classifying such items in revenues. If significant, please disclose any exchange rate changes subsequent to year-end and its effects on unsettled balances related to foreign currency transactions. Please refer to paragraph 32 of SFAS 52.

As calculated in accordance with paragraph 15 of SFAS 52, our aggregate transaction gains or losses recorded in the consolidated statements of income for the three years ended December 31, 2004 are:

2004:	pre-tax loss of	$	1,412,189
2003:	pre-tax income of	$	676,523
2002:	pre-tax income of	$	24,546

In explaining why the transaction gains and losses are recorded in operating revenues on the income statement and were not quantified in our 10-K disclosures as required by paragraph 30 of SFAS 52, it is important to note that these transactions were part of our gas marketing subsidiary's operations. These operations meet the GAAP definition of an "energy trading activity." As required by EITF 02-03, we recorded gains and losses from "energy trading activities" on a net basis in the income statement. This includes the contracts that generated the foreign currency transaction gains/losses. We haven't quantified the foreign currency gain/loss in our disclosures as in the presentation they are netted with gains/losses from other energy trading contracts. Since our business strategy employs limited speculative positions, generally the foreign currency transaction gain/loss is offset by the gain/loss on a contract used to hedge (not designated as a hedge under the provisions of SFAS 133) the foreign currency exposure, or by being "long" or "short" in the foreign currency. Therefore, quantifying the foreign currency gain/loss as provided above could confuse or mislead the reader when the impact from our total exposure to foreign currency was not significant to the consolidated financial statements.

Paragraph 32 of SFAS 52 requires "...disclosure of the rate change and its effect on unsettled balances pertaining to foreign currency transactions, if significant....." The changes in the U.S./Canadian dollar exchange rate subsequent to year end did not result in a significant impact to the Company and therefore, we believe, did not require disclosure.

<u>Oil and Gas Operations, page 87</u>

<u>Comment No. 8</u>:

We note that you account for your oil and gas activities under the full cost method and are subject to a ceiling test. You maintain a portfolio of swaps to hedge a portion of your crude oil and natural gas production. These derivative transactions are accounted for as cash flow hedges. Please tell us if your computation of the limitation of capitalized costs includes the impact of the aforementioned cash flow hedges. Please refer to SAB Topic 12: D(3)(b).

In the course of preparing our response to your Comment 8, we determined that the "ceiling test" calculation for 2004 did not include the present value impact of our cash flow hedges. While our "ceiling test" calculations in past years included the impact, it was inadvertently left out in 2004. Nonetheless, we have determined that including the impact of our cash flow hedges would not have resulted in a "ceiling test" adjustment for 2004. At 12/31/04, inclusion of the cash flow hedge impact would have reduced the present value of the future cash flows in our "ceiling test" by approximately $1.3 million, an insignificant amount relative to the substantial amount by which our discounted revenues exceeded our capitalized costs. We will include the impact of our cash flow hedges in future "ceiling test" calculations.

<u>Revenue Recognition, page 89</u>

<u>Comment No. 9</u>:

We note that you sell a substantial majority of your unregulated capacity and energy under tolling arrangements. We assume you classify such revenues net of the related fuel costs. If you classify such transactions on a gross basis, explain your rationale under EITF 99-19 and explain why such contracts do not constitute energy trading. In doing so, please reference each of the indicators of gross and net revenue reporting in EITF 99-19.

The Staff's assumption is correct. Revenues from our tolling arrangements are presented net of the related fuel costs.

Earnings Per Share of Common Stock, page 89

Comment No. 10:

We note that you granted restricted common shares and/or restricted stock units in each of the last three fiscal years and such awards could be subject to return. Please tell us your treatment of these shares in determining the number of shares outstanding used in your calculation of basic and diluted earnings per share. Refer to paragraph 10 of SFAS 128. In addition, please help us understand how you determined that your restricted shares are anti-dilutive.

Paragraph 10 of SFAS 128 states that outstanding common shares that are contingently returnable shall be treated in the same manner as contingently issuable shares and shall be considered outstanding common shares and included in the computation of basic earnings per share (EPS) as of the date that all necessary conditions have been satisfied.

Paragraph 20 of SFAS 128 provides guidance on non-vested stock to be issued to an employee under a stock-based compensation arrangement. It states that such stock based awards shall be considered to be outstanding as of the grant date for purposes of computing diluted EPS, even though their exercise may be contingent upon vesting and the dilutive effect shall be computed using the treasury stock method.

Paragraph 21 of SFAS 128 discusses the calculation of assumed proceeds to be applied to the treasury stock method. If the tax deduction for compensation is less than the compensation expense recognized for financial reporting purposes, then the difference in income taxes shall be treated as a reduction in net proceeds.

Treatment for Restricted Stock and Restricted Stock Units – Vested shares are outstanding for both basic and diluted EPS purposes in accordance with Paragraph 10 of SFAS 128 because all conditions have been satisfied. The non-vested shares vest solely on continued employment and are included in the computation of diluted EPS using the treasury stock method in accordance with Paragraphs 20 and 21 of SFAS 128.

There were no anti-dilutive restricted shares in 2004. Some non-vested restricted shares were anti-dilutive in 2003 and 2002 because the sum of the average open market price for those years, that was applied in the treasury stock calculation, plus the reduction in net proceeds for the difference in income taxes (the tax deduction compensation under the treasury stock method was lower than the compensation expense recognized for financial reporting purposes) was lower than the market price at time of grant for certain restricted stock grants resulting in negative shares in the treasury stock calculation.

Note 4. Property, Plant and Equipment, page 98

Comment No. 11:

You disclose that separate categories of property, plant and equipment are depreciated over a wide range of useful lives. Please disclose the weighted average useful lives related to each category.

Weighted average useful lives of property, plant and equipment at December 31, are as follows:

Regulated

	2004 Weighted Average Useful Life	2003 Weighted Average Useful Life
Electric plant:		
Production	45	45
Transmission	44	44
Distribution	32	32
General	18	17

Non-regulated

	2004 Weighted Average Useful Life	2003 Weighted Average Useful Life
Coal mining	16	15
Oil & gas	8	8
Energy marketing and transportation	23	23
Power generation	29	29
Communications	13	13
Other	7	4

To provide additional clarity to our disclosures, we will include weighted average lives related to each category of property, plant and equipment in our future filings.

Comment No. 12:

If rate recovery of generation-related costs becomes unlikely or uncertain due to competition or regulatory action, the provisions of SFAS 71 may no longer apply to Black Hill Power's generation operations. In the event that Black Hills Power determines that it no longer meets the criteria for following SFAS 71, the accounting impact could include a material charge to your consolidated statement of income. Please disclose the amount of carrying value of your regulated generation assets that would not exist if such plant would have been accounted for outside of SFAS 71 for all periods presented.

We believe that the "Regulatory Accounting" disclosure on page 85 of the 10-K provides the most meaningful information with respect to the possible future inapplicability of SFAS 71. We do not believe it is possible to estimate the carrying value of our regulated generation assets if SFAS 71 were no longer applicable. The guidance promulgated by paragraph 6 of SFAS No. 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71" states the following:

> "...the carrying amounts of plant, equipment, and inventory measured and reported pursuant to Statement 71 shall not be adjusted unless those assets are impaired, in which case the carrying amounts of those assets shall be reduced to reflect that impairment. Whether those assets have been impaired shall be judged in the same manner as for enterprises in general."

Based on this guidance, the carrying value of our regulated generation assets would be the same if SFAS 71 no longer applied, unless the assets failed an impairment test under SFAS 144. We do not feel it is practical to attempt to estimate what the results of a SFAS 144 impairment test would be at a hypothetical future date. We have therefore only included in our "Regulatory Accounting" disclosure the fact that a material charge could be incurred if SFAS 71 were no longer applicable to our regulated activities. In future filings, we will clarify that the carrying value of our regulatory assets could change materially if regulatory accounting were no longer applicable and our regulated assets were to fail an impairment test.

Note 15, Gain on Sale of Assets, page 107

Comment No. 13:

Please tell us your basis for offsetting the gain to "Operating expenses." We may have further comment.

In classifying the gain on sale of assets not qualifying as a "component of an entity" we relied on the guidance provided in paragraph 45 of SFAS 144, as follows:

> Reporting Disposal Gains or Losses in Continuing Operations
> 45. A gain or loss recognized for a long-lived asset (disposal group) classified as held for sale that is not a component of an entity shall be included in income from continuing operations before income taxes in the income statement of a business enterprise and in income from continuing operations in the statement of activities of a not-for-profit organization. If a subtotal such as "income from operations" is presented, it shall include the amounts of those gains or losses.

Note 18, Other Comprehensive Income (Loss), page 111

Comment No. 14:

Please tell us your accounting treatment for payments on or receipts from interest rate swap agreements designated as cash flow hedges whose underlying debt has interest expense that is capitalized. Please include the capitalization policy associated with the payments or receipts on such interest rate swaps and the period(s) in which such payments or receipts impact earnings. Refer to EITF 99-9.

In the past, none of our interest rate swaps which have been designated as cash flow hedges have had underlying debt for which we have capitalized any interest payments. All of the interest rate swaps designated as cash flow hedges and related to our construction projects were entered into subsequent to the completion of construction. These power projects had separate "construction financing" and "long-term project financing." The interest rate swaps were designated as cash flow hedges of the "long-term project financings," not the "construction financings."

If we use an interest rate swap as a hedge of construction term financing on a future project, and designate the swap as a hedge in accordance with SFAS 133, our capitalization policy associated with the payments/receipts on such swap will be in accordance with EITF 99-9.

Comment No. 15:

We note that you included the reclassification adjustment in 2003 for interest rate swaps designated as cash flow hedges settled as part of an asset sale and included in net income. Please revise your Consolidated Statements of Stockholders' Equity and Note 11 Comprehensive Loss to include the reclassification adjustments related to gains or losses on your cash flow hedges that were realized and included in net income for all applicable periods. Please refer to paragraphs 18-21 of SFAS 130.

Paragraph 20 of SFAS 130 allows a net presentation of Other Comprehensive Income on the face of the financial statements and a gross presentation in the footnotes. This is the presentation method we have followed. While a gross method was followed in Note 18 to the financial statements, we did not view the 2004 and 2002 reclassification adjustments as significant and therefore aggregated them with other OCI adjustments related to our cash flow hedges. This was not the case in 2003 as these reclassification adjustments were significant and were therefore presented separately.

Note 20, Employee Benefit Plans, page 114

Comment No. 16:

Please explain to us how you calculate the market related value of plan assets as that term is determined in SFAS 87. Since there are alternative ways to calculate the market value of plan assets and it has a direct impact on your pension expense, we believe you should disclose how you determine this amount in future filings.

Assets held in our non-contributory defined benefit plan are stated at fair value as determined by the trustee through reference to quoted market prices, except for the deposits with Equitable Life Assurance Society, which are stated at cost which approximates market value.

We will disclose our method for determining the market value of plan assets in our future filings.

<u>Note 23, Business Segments, page 129</u>

<u>Comment No. 17</u>:

Please provide information about the extent of reliance on your major customers. If revenues from transactions with a single external customer amount to 10 percent or more of your revenues, you should disclose that fact, and the total amount of revenues from each such customer. Please refer to paragraph 39 of SFAS 131.

In 2004, we only had one instance where revenues from a single customer exceeded 10 percent of consolidated revenues. In this case it was a customer of our crude oil marketing operations for which we present marketing revenues and cost of sales on a gross basis in accordance with GAAP, as contrasted with our larger gas marketing operations, which we present on a net basis, also in accordance with GAAP. Although this oil marketing customer accounted for approximately 11 percent of consolidated revenues, we felt it would be misleading to discuss our dependence on this customer as if it were a major customer. This rationale stems from the fact that the revenues generated by our crude oil marketing business have a corresponding cost of sale which nets to a small marketing margin. If we lost this customer, the marketing margin lost would not have a significant impact on our consolidated results.

No single customer contributed revenues in excess of 10 percent of total consolidated revenues in 2003 or 2002.

<u>Note 25. Cheyenne Acquisition, page 134</u>

<u>Comment No. 18</u>:

Please tell us how you accounted for any contracts between yourself and CLF&P in the application of purchase accounting. In this regard, tell us whether any amounts existed on either your books of CLF&P relating to such contracts immediately prior to consummation.

We have two contracts involving CLF&P. The contracts are power sales agreements to sell power from our Gillette CT and Wygen power plants. These contracts are temporarily assigned for a four-year term to CLF&P’s former sister company Public Service Company of Colorado (PSCo) and revert back to CLF&P after December 31, 2007 through the remainder of the ten year terms on the contracts. These contracts were approved by the Wyoming Public Service Commission in connection with CLF&P’s execution of a four-year, all-requirements power purchase agreement with PSCo and are considered part of CLF&P’s cost of service for rate making purposes.

Immediately prior to the consummation of our acquisition of CLF&P, no amounts existed on our books or the books of CLF&P related to these contracts. In our application of purchase accounting for the CLF&P acquisition, we did not assign value to the contracts that are included as a cost of service for rate making at CLF&P.

Note 26. Oil and Gas Reserves and Related Financial Data

Reserves, page 135

Comment No. 19:

We note the large negative revision in gas reserves in 2004 which you attribute primarily to the East Blanco Field in New Mexico. Based on the drilling and well work and the apparent lower than expected production, did you lower per well PUD reserves in 2004 for the remaining PUD locations in the East Blanco Field? Were the total East Blanco Field reserves reduced, and if so, by how much and what was the basis for the reduction? Supplementally, please clarify this reserve revision to us.

(1) *Did you lower per well PUD reserves in 2004 for the remaining PUD locations in the East Blanco Field?* Yes, there were 19 PUDs in 2003 that remained as PUDs in 2004 and where applicable, the reserves for the remaining 2003 PUDs were revised, resulting in a total 2.7 Bcf downward revision in the 2004 reserve evaluation. In 2003, the average per well reserve estimates for the 19 PUDs was 0.75 Bcfe (range 0.28 to 1.20 Bcfe). In 2004, the average per well reserve estimate was reduced to 0.61 Bcfe (range 0.23 to 1.20 Bcfe). Thus, average reserve estimates per well were reduced by 0.14 Bcfe, or approximately 19 percent.

(2) *Were the total East Blanco Field reserves reduced, and if so, by how much and what was the basis for the reduction?* No, total reserves for East Blanco Field increased in 2004. Although revisions to previous field estimates accounted for a 26 Bcf decrease, 50.7 Bcf was added to the field in 2004 as new additions, while 2004 production was 5.0 Bcf, resulting in a net field increase of 19.7 Bcf.

(3) *Clarification for reserve revision.* In preparation of the reserve disclosure in our 2004 10-K, we recognized the significance of the revisions to previous estimates and therefore attempted to add clarity for the reader as included in the final two paragraphs on page 135 of the 10-K. Further, explanatory detail is provided for the Staff as follows:

During 2004 we drilled twenty-six new vertical wells and attempted about sixty-seven individual zone completions in the Tertiary, Fruitland Coal and Pictured Cliffs horizons in the East Blanco Field with a 79% success ratio. The success rate in the Tertiary formations alone was approximately 61%. Also in 2004, twenty-four existing wells were recompleted in the Tertiary and/or Pictured Cliffs formations with varying degrees of success (including seven horizontal recompletions into the Pictured Cliffs Formation). As a result of these activities, the 2004 year-end reserve estimate incorporated our gained knowledge and experience with the acquired Mallon properties (subsequent to December 31, 2003) from new well completions and existing well recompletions in multiple horizons of the Tertiary San Jose, Nacimiento and Ojo Alamo and the Cretaceous Fruitland Coal and Pictured Cliff formations in the East Blanco Field.

Overall, our field expansion efforts into the undeveloped portions of our leasehold contributed to substantial field wide reserve additions of 50.7 Bcf from the four primary producing Tertiary and Cretaceous formations in all reserve categories including 1.3 Bcf of Proved Developed Behind Pipe (PBP) (5 wells), 3.0 Bcf of Proved Developed Producing (PDP) (7 wells) and 46.4 Bcf of PUD (58 wells). However, less than expected results from our 2004 completions and recompletion program caused us to revise downward reserve estimates for the 2003 PUD reserves (19 wells) by 2.7 Bcf. Further, these 2004 completion results caused us to revise 2003 Proved Developed Non-Producing (PNP) and 2003 PBP downward by 17.0 Bcf from 71 wells. Fourteen well locations which had been booked in our 2003 reserve study as PUD (4 wells) , PBP (3 wells), and PNP (7 wells) were reclassified through 2004 drilling and completion activities to PDP status by year-end 2004 and accounted for a total downward reserve revision of approximately 4.0 Bcf based on actual results. Miscellaneous 2003 PUD's were revised downward 2.3 Bcf for cancelled drilling permits and various other factors.

Comment No. 20:

SupplementalIy, tell us how much the reserves that were written off at the East Blanco field in 2004 lowered your DD&A and increased earnings in 2003. Do you consider this amount to be material? We may have additional comments.

In responding to the Staff's comment, we would like to emphasize the fact that we used the best well performance information available to us at the time we developed our reserve estimates used in performing our DD&A calculation in 2003. As explained in our response to comment 19 above, our developmental drilling and recompletion activity in 2004 provided additional production performance results that differed from the information used to develop our reserve estimates in 2003.

Hypothetically, if we had this additional well performance information in 2003 on the recently acquired properties, 2003 DD&A would have increased by approximately $1.7 million. This would have resulted in a $1.1 million decrease in our net income which would have been booked at the time.

We would appreciate your earliest possible review of this letter in response to your comments. To expedite the conveyance of additional comments, please feel free to call Jeff Berzina at (605) 721-2346 at any time.

Sincerely,

BLACK HILLS CORPORATION

/s/ MARK T. THIES
Mark T. Thies
Executive Vice President and Chief Financial Officer