IDAHO POWER
An IDACORP Company

IDAHO POWER COMPANY
P.O. BOX 70
BOISE, IDAHO 83707

PATRICK A. HARRINGTON
Attorney

HAND-DELIVERED

April 27, 2006

Ms. Jean D. Jewell
Secretary
Idaho Public Utilities Commission
Statehouse
Boise, Idaho 83720

Re: In the Matter of the Application of Idaho Power Company to enter into certain financing transactions for the Refunding of $116,300,000 of Sweetwater County, Wyoming Pollution Control Revenue Refunding Bonds

Case No. IPC-E-06- 14

Dear Ms. Jewell:

Enclosed herewith for filing with the Commission are an original and five (5) copies of the above referenced application. Idaho Power will promptly submit the $1,000 application filing fee to the Commission for this application. Please send ten (10) certified copies of the Order issued in this matter to the undersigned.

Please contact me at 388-2878 if you have any questions regarding this filing.

Sincerely,

Patrick A. Harrington

c: D.C. Gribble
Terri Carlock

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY TO ENTER INTO CERTAIN FINANCING TRANSACTIONS FOR THE REFUNDING OF $116,300,000 OF SWEETWATER COUNTY, WYOMING, POLLUTION CONTROL REVENUE REFUNDING BONDS	)	CASE NO. IPC-E-06-14 APPLICATION

Idaho Power Company (the "Applicant") hereby applies for an Order from the Idaho Public Utilities Commission (the "Commission") under Title 61, Idaho Code, Chapters 1 and 9, and Rules 141 through 150 of the Commission's Rules of Practice and Procedure (the "Rules") for authority to enter into certain financing transactions for the refunding of $116,300,000 aggregate principal amount of Sweetwater County, Wyoming, Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 1996A, 1996B and 1996C (the "Outstanding Bonds"), which consist of $68,100,000 principal amount of Series 1996A Bonds ("Series 1996A Bonds"), $24,200,000 principal amount of Series 1996B Bonds ("Series 1996B Bonds") and $24,000,000 principal amount of Series 1996C Bonds ("Series 1996C Bonds"). The Outstanding Bonds were issued by Sweetwater County, Wyoming ("Sweetwater County") on August 29, 1996. The Commission approved the Applicant's participation in the issuance of the Outstanding Bonds in 1996 in Case No. IPC-E-96-11, Order No. 26521.

The proceeds of the Outstanding Bonds were applied to refinance prior Sweetwater County, Wyoming, pollution control revenue bonds, which were issued in the 1970s and 1980s to finance a portion of the cost of acquiring, constructing and installing Applicant's undivided interest in certain air and water pollution control facilities at the Jim Bridger coal-fired, steam electric generating plant located near Rock Springs, Wyoming.

Under the proposed refunding transaction, Sweetwater County will issue and sell not to exceed $116,300,000 aggregate principal amount of one or more series of pollution control revenue refunding bonds (the "Refunding Bonds") and loan the proceeds from such sale to the Applicant. The loan proceeds, together with certain monies from the Applicant, will be used to refund $116,300,000 aggregate principal amount of the Outstanding Bonds. The Applicant will provide for the repayment of the Refunding Bonds through a loan agreement and other arrangements with Sweetwater County. The Applicant proposes to enter into the refunding transaction to secure a lower average interest rate for the Refunding Bonds as compared with the Outstanding Bonds.

(a) The Applicant

The Applicant is an electric public utility engaged principally in the generation, purchase, transmission, distribution and sale of electric energy in an approximately 20,000 square-mile area, in southern Idaho and eastern Oregon. The Applicant was initially incorporated under the laws of the State of Maine and subsequently migrated its state of incorporation from the State of Maine to the State of Idaho effective June 30, 1989. It is duly qualified to do business as a foreign corporation in the States of Oregon, Nevada, Montana and Wyoming in connection with its utility business. The principal executive offices of the Applicant are located at 1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070; its telephone number is (208) 388-2200.

(b) Description of Securities

(1) Amount

The Refunding Bonds will not exceed $116,300,000 in aggregate principal amount, which represents the total principal amount of the Outstanding Bonds presently outstanding. The Refunding Bonds may be collateralized with the Applicant's First Mortgage Bonds or other substitute collateral, in aggregate principal amount not to exceed the aggregate principal amount of the Refunding Bonds. Applicant may also enter into guarantees, pledges or other security agreements or arrangements to insure timely payment of amounts due in respect of the Refunding Bonds. In addition, the Applicant may enter into letters of credit, insurance or other arrangements with unrelated parties pursuant to which such parties may lend additional credit or liquidity support to the Refunding Bonds. The purpose of such additional credit or liquidity support would be to enhance the credit rating of the Refunding Bonds and thereby reduce the interest expense of the Refunding Bonds.

(2) Interest Rate

The interest rate or rates may be fixed or variable for the Refunding Bonds and may be converted to fixed or variable rate(s) during the term(s) of the Refunding Bonds. The Applicant will notify the Commission by letter within seven (7) days (or as soon as possible, if the required information is not available within seven (7) days) before the issuance of the Refunding Bonds of the likely range of interest rates and other terms for the Refunding Bonds.

(3) Date of Issue

The Applicant expects that the Refunding Bonds will be issued on or prior to July 15, 2006, which is the first redemption date of the Series 1996A Bonds. The Series

1996B Bonds and the Series 1996C Bonds may be redeemed at any time. The Refunding Bonds may be issued prior to July 15, 2006 to take advantage of favorable interest rates.

(4) Date of Maturity

The maturity date for the Refunding Bonds will be July 15, 2026, the same maturity date as for the Outstanding Bonds.

(5) Call or Redemption Privileges

To be determined.

(6) Sinking Fund or Other Provisions for Securing Payment

Any sinking fund provisions are yet to be determined for the Refunding Bonds. See section (c) below for a discussion of possible security agreements or arrangements.

(c) Method of Issuance

The Refunding Bonds will be issued pursuant to an indenture of trust between Sweetwater County and a trustee. Pursuant to a loan agreement between Sweetwater County and the Applicant, the proceeds from the sale of the Refunding Bonds will be loaned to the Applicant to pay for the refunding of $116,300,000 aggregate principal amount of the Outstanding Bonds. Under the loan agreement, the Applicant will be obligated to pay absolutely and unconditionally, to the extent sufficient funds are not already in the possession of the trustee, the principal of, interest on, and premium, if any, on the Refunding Bonds as well as certain fees and expenses associated with the transaction. Sweetwater County's full faith and credit will not be pledged to the payment of the Refunding Bonds.

To achieve favorable ratings by national bond rating agencies for the Refunding Bonds, the Applicant may collateralize the Refunding Bonds with its own First Mortgage Bonds or other substitute collateral, or it may enter into guarantees, pledges or other security agreements or arrangements to insure timely payment of amounts due in respect of the Refunding Bonds. The Applicant may also enter into letters of credit, insurance or other arrangements with unrelated parties pursuant to which such parties may lend additional credit or liquidity support to the Refunding Bonds. The purpose of such additional credit or liquidity support would be to enhance the credit rating of the Refunding Bonds and thereby reduce the interest expense of the Refunding Bonds.

(1) Method of Marketing

The Refunding Bonds will be sold on a negotiated public offering basis by Sweetwater County to the underwriters selected for the transaction (the "Underwriters"), pursuant to a contract of purchase. The Underwriters will be JP Morgan Securities Inc.; Wachovia Capital Markets, LLC; Banc of America Securities LLC; and KeyBanc Capital Markets.

(2) Terms of Sale

To be determined.

(3) Underwriting Discounts or Commissions

The Underwriters will receive a fee of 0.45% of the aggregate principal amount of the Refunding Bonds offered.

(4) Sales Price and Net Proceeds to the Applicant

For tax purposes, the costs of issuance of the Refunding Bonds will be paid separately by Applicant and not from the proceeds of the Refunding Bonds. The costs of issuance of the Refunding Bonds, in total amounts and as a percentage of the gross proceeds of the Refunding Bonds, are estimated to be:

	Total	Per $100
Gross Proceeds	$116,300,000	$100.000
Costs of Issuance to Applicant:		
Underwriter's Commission (0.45%)	$523,350	.450
Other Issuance Expenses (see below)	900,000	0.7738
Redemption Premium for Series 1996A Bonds (2.00%)	1,362,000	1.171
Total Costs of Issuance to Applicant	$2,785,350	2.3948

Other Issuance Expenses:

Trustee Fees	$ 12,000.00
Regulatory Agency Fees	3,500.00
The Applicant's and Other Counsel Fees	700,000.00
Accounting Fees	20,000.00
Printing and Engraving Fees	20,000.00
Rating Agency Fees	120,000.00
Miscellaneous Costs	24,500.00
TOTAL	$900,000.00

Applicant states that, under federal tax laws, it will not be able to increase the principal amount of the Refunding Bonds to include the redemption premium of the Series 1996A Bonds or the underwriter fees or costs of issuance of the Refunding Bonds. Accordingly, the Applicant intends to record these amounts as unamortized debt expense and amortize them over the life of the Refunding Bonds.

(d) Purpose of Issuance

The net proceeds to be received by the Applicant in connection with the sale of the Refunding Bonds will be used to refund $116,300,000 aggregate principal amount outstanding of the Outstanding Bonds. To the extent that the proceeds of the Refunding Bonds are not immediately applied to the refunding of the Outstanding Bonds, they may be temporarily invested by the trustee in high grade, short-term taxable securities and short-term government obligations.

(e) Propriety of Issue

The Applicant believes and alleges that facts set forth herein disclose that the proposed issuance of Refunding Bonds is for a lawful object within the corporate purposes of the Applicant and compatible with the public interest, and is necessary or appropriate for, or consistent with, the proper performance by the Applicant of service as a public utility and will not impair its ability to perform that service, and is reasonably necessary or appropriate for such purposes.

(f) Financial Statements; Resolutions

The Applicant has filed herewith as Attachment I its financial statements dated as of December 31, 2005 consisting of its (a) Actual and Pro Forma Balance Sheet and Notes to Financial Statements, (b) Statement of Capital Stock and Funded Debt, (c) Commitments and Contingent Liabilities, (d) Statement of Retained Earnings and (e) Statement of Income. Applicant's directors are scheduled to adopt resolutions approving the transaction described in this Application at their regularly scheduled meeting on May 18, 2006. A certified copy of the resolutions will thereupon be filed with the Commission as Attachment II to this Application.

(g) Proposed Order

The Applicant has filed as Attachment III a Proposed Order for adoption by the Commission if this Application is granted.

(h) Notice of Application

Notice of this Application will be published in those newspapers in the Applicant's service territory listed in Rule 141.08 of the Commission's Rules within seven (7) days of the date hereof.

WHEREFORE, the Applicant requests that the Idaho Public Utilities Commission issue its Order authorizing the Applicant to (1) enter into contracts of purchase, loan agreements, letter of credit agreements, insurance agreements, security agreements and such other agreements or arrangements as may be reasonably necessary in connection with the issuance by Sweetwater County, for the benefit of the Applicant, of up to $116,300,000 aggregate principal amount of pollution control revenue refunding bonds, and the loan of the proceeds thereof from Sweetwater County to the Applicant; and (2) assume liability as guarantor, pledgor, surety or otherwise (including issuance of the Applicant's First Mortgage Bonds or other substitute collateral) with respect to the principal of, interest on, and premium, if any, on the Refunding Bonds; all for the purpose of effecting the refunding of $116,300,000 aggregate principal amount of the Outstanding Bonds, under the terms and conditions of and as set forth in this Application. The Applicant also requests that the redemption premium on the Series 1996A Bonds, the underwriter's fees and costs of issuance of the Refunding Bonds be treated as unamortized debt expense amortized over the life of the Refunding Bonds.

DATED at Boise, Idaho this 27th day of April, 2006.

IDAHO POWER COMPANY

By: /s/ Dennis C. Gribble
Vice President and Treasurer

(CORPORATE SEAL)

ATTEST:

/s/ Patrick A. Harrington
Attorney
Idaho Power Company
1221 W. Idaho Street
P.O. Box 70
Boise, Idaho 83707-0070

VERIFICATION

I, Dennis C. Gribble, declare that I am the Vice President and Treasurer of Idaho Power Company and am authorized to make this Verification. The Application and the attached exhibits were prepared at my direction and were read by me. I know the contents of the Application and the attached exhibits, and they are true, correct and complete to the best of my knowledge and belief.

WITNESS my hand and seal of Idaho Power Company this 27th day of April, 2006.

/s/ Dennis C. Gribble

SUBSCRIBED AND SWORN to before me this 27th day of April, 2006.

Joanne M. Butler
Notary Public for Idaho
Residing at Boise, Idaho
My Commission Expires: 10-5-07

JOANNE M. BUTLER NOTARY PUBLIC STATE OF IDAHO

ATTACHMENT I(a)

IDAHO POWER COMPANY
BALANCE SHEET
As of December 31,2005

ASSETS

	Actual
Electric Plant :	
In service (at original cost)	$ 3,477,066,789
Accumulated provision for depreciation	(1,364,640,116)
In service - Net	2,112,426,673
Construction work in progress	149,814,313
Held for future use	2,906,206
Electric plant - Net	2,265,147,192
Investments and Other Property:	
Nonutility property	922,349
Investment in subsidiary companies	43,512,409
Auction rate securities	
Other	28,362,825
Total investments and other property	72,797,583
Current Assets:	
Cash and cash equivalents	49,314,066
Receivables:	
Customer	49,830,007
Allowance for uncollectible accounts	(833,238)
Notes	3,272,699
Employee notes	2,950,551
Related party	637,084
Other	7,398,828
Accrued unbilled revenues	38,905,298
Materials and supplies (at average cost)	30,451,220
Fuel stock (at average cost)	11,738,622
Prepayments	17,532,436
Regulatory assets	3,064,199
Total current assets	214,261,772
Deferred Debits:	
American Falls and Milner water rights	31,585,000
Company owned life insurance	35,400,820
Regulatory assets associated with income taxes	343,052,434
Regulatory assets - PCA	44,851,834
Regulatory assets - other	27,272,723
Employee notes	2,861,740
Other	42,187,721
Total deferred debits	527,212,272
Total	$ 3,079,418,819

IDAHO POWER COMPANY
BALANCE SHEET
As of December 31,2005

CAPITALIZATION AND LIABILITIES

	Common Shares Authorized	Common Shares Outstanding		Actual
Equity Capital:	50,000,000	39,150,812		
Common stock			$	97,877,030
Preferred stock				
Premium on capital stock				483,707,552
Capital stock expense				(2,096,925)
Retained earnings				361,256,133
Accummulated other comprehensive income				(3,425,324)
Total equity capital				937,318,467
Long-Term Debt:				
First mortgage bonds				785,000,000
Pollution control revenue bonds				170,460,000
Other long-term debt				
American Falls bond and Milner note guarantees				31,585,000
Unamortized discount on long-term debt (Dr)				(3,325,109)
Total long-term debt				983,719,891
Current Liabilities:				
Long-term debt due within one year				
Notes payable				-
Accounts payable				79,433,338
Notes and accounts payable to related parties				10,254,003
Taxes accrued				72,183,707
Interest accrued				14,104,405
Deferred income taxes				3,064,199
Other				19,182,265
Total current liabilities				198,221,917
Deferred Credits:				
Regulatory liabilities associated with accumulated deferred investment tax credits				68,786,273
Deferred income taxes				503,316,742
Regulatory liabilities associated with income taxes				41,627,445
Regulatory liabilities-other				234,695,427
Other				111,732,657
Total deferred credits				960,158,544
Total			$	3,079,418,819

IDAHO POWER COMPANY
NOTES TO FINANCIAL STATEMENTS
As of December 31, 2005

1. Management Estimates:

Management makes estimates and assumptions when preparing financial statements in conformity with accounting principles generally accepted in the United States of America. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. As a result, actual results could differ from those estimates.

2. Property Plant and Equipment:

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, Allowance for Funds Used During Construction (AFDC) and indirect charges for engineering, supervision and similar overhead items. Maintenance and repairs of property and replacements and renewals of items determined to be less than units of property are expensed to operations. Repair and maintenance costs associated with planned major maintenance are recorded as these costs are incurred. For utility property replaced or renewed, the original cost plus removal cost less salvage is charged to accumulated provision for depreciation, while the cost of related replacements and renewals is added to property, plant and equipment.

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.91 percent in 2005, 2.96 percent in 2004 and 2.99 percent in 2003.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under Statement of Financial Accounting Standards (SFAS) 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS 144 requires that if the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements.

3. Allowances For Funds Used During Construction:

AFDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the rate-making process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. IPC's weighted-average monthly AFDC rates for 2005, 2004 and 2003 were 7.4 percent, 6.9 percent and 8.3 percent, respectively. IPC's reductions to interest expense for AFDC were $3 million annually from 2003 to 2005. Other income included $5 million, $4 million and $3 million for 2005, 2004 and 2003, respectively.

4. Revenues:

IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at month-end. IPC collects franchise fees and similar taxes related to energy consumption. These amounts are recorded as liabilities until paid to the taxing authority. None of these collections are reported on the income statement as revenue or expense.

5. Power Cost Adjustment:

IPC has a Power Cost Adjustment (PCA) mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered or over-recovered portion, is then included in the calculation of the next year's PCA.

6. Income Taxes:
The liability method of computing deferred taxes is used on all temporary differences between the book and tax basis of assets and liabilities and deferred tax assets and liabilities are adjusted for enacted changes in tax laws or rates. Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction, IPC's deferred income taxes (commonly referred to as normalized accounting) are provided for the difference between income tax depreciation and straight-line depreciation computed using book lives on coal-fired generation facilities and properties acquired after 1980. On other facilities, deferred income taxes are provided for the difference between accelerated income tax depreciation and straight-line depreciation using tax guideline lives on assets acquired prior to 1981. Deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods do not provide for current recovery in rates. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

The State of Idaho allows a three-percent investment tax credit on qualifying plant additions. Investment tax credits earned on regulated assets are deferred and amortized to income over the estimated service lives of the related properties. Credits earned on non-regulated assets or investments are recognized in the year earned.

7. Stock-based Compensation:
Stock-based employee compensation is accounted for under the recognition and measurement principles of Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees," and related interpretations. Grants of performance shares are reflected in net income based on the market value at the award date, or the period-end price for shares not yet vested. Grants of restricted stock are reflected in net income based on the market value on the grant date. No stock-based employee compensation cost is reflected in net income for stock options, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. IPC has adopted the disclosure only provision of SFAS 123, "Accounting for Stock-Based Compensation."

The following table illustrates the effect on net income if the fair value recognition provisions of SFAS 123 had been applied to stock-based employee compensation:

	2005	2004	2003
	(thousands of dollars except for per share amounts)		
IPC			
Net income, as reported	$ 71,839	$ 70,608	$ 58,591
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	108	276	(56)
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	568	977	1,073
Pro forma net income	$ 71,379	69,907	$ 57,462

For purposes of these pro forma calculations, the estimated fair value of the options, restricted stock and performance shares are amortized to expense over the vesting period. The fair value of the restricted stock and performance shares is the market price of the stock on the date of grant. The fair value of an option award is estimated at the date of grant using a binomial option-pricing model. Expense related to forfeited options is reversed in the period in which the forfeit occurs.

IPC has two employee stock-based compensation plans, the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (Restricted Stock Plan). These plans are intended to align employee and shareholder objectives related to its long-term growth. IPC also has one non-employee stock-based compensation plan, the Director Stock Plan (DSP). The purpose of the DSP is to increase directors' stock ownership through stock-based director compensation.

The LTICP for officers, key employees and directors permits the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares and other awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2005, the maximum number of shares available under the LTICP and RSP were 1,552,802 and 74,839, respectively.

All options granted have an exercise price equal to the market price of IDACORP's stock on the date of grant. In accordance with APB 25, no compensation costs have been recognized for the option awards.

Stock option transactions are summarized as follows:

	2005		2004		2003	
	Number Of shares	Weighted average exercise price	Number of Shares	Weighted average exercise price	Number Of shares	Weighted average exercise price
Outstanding beginning of year	952,600	$ 32.38	886,800	$ 32.48	591,000	$ 38.33
Granted	157,837	29.75	110,500	31.21	343,000	22.95
Exercised	-	-	(4,200)	22.92	-	-
Forfeited	(16,300)	30.27	(40,500)	32.27	(47,200)	36.42
Outstanding end of year	1,094,137	$ 32.03	952,600	$ 32.38	886,800	$ 32.48
Exercisable	559,140	$ 34.41	373,600	$ 35.42	211,000	$ 37.83

The following table summarizes information about stock options outstanding at December 31, 2005:

	Outstanding			Exercisable	
Exercise Price Ranges	Number of shares	Weighted average exercise Price	Weighted average remaining contractual life	Number of shares	Weighted Average Exercise Price
\$22.92 - \$31.21	575,537	$ 26.27	7.87 years	147,340	$ 24.09
\$35.81 - \$40.31	518,600	$ 38.43	5.28 years	411,800	$ 38.10

Restricted stock and performance share awards are compensatory awards and IPC accrues compensation expense, which is charged to operations, based upon the market value of the granted shares. For 2005, 2004 and 2003, total compensation accrued under the Restricted Stock Plan was less than $1 million annually.

The following table summarizes restricted stock activity:

	2005	2004	2003
Shares outstanding - beginning of year	121,420	80,454	77,192
Shares granted	87,620	67,056	41,945
Shares forfeited	(25,220)	(24,014)	(1,889)

Shares issued	(251)	(2,076)	(36,794)
Shares outstanding - end of year	183,569	121,420	80,454
Weighted average fair value of current year stock grants on grant date	$ 29.75	$ 31.15	$ 22.95

8. Cash and Cash Equivalents:
Cash and cash equivalents include cash on hand and highly liquid temporary investments with maturity dates at date of acquisition of three months or less.

9. Derivative Financial Instruments:
Financial instruments such as commodity futures, forwards, options and swaps are used to manage exposure to commodity price risk in the electricity market. The objective of the risk management program is to mitigate the risk associated with the purchase and sale of electricity and natural gas as well as to optimize energy marketing portfolios. The accounting for derivative financial instruments that are used to manage risk is in accordance with the concepts established by SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended.

10. Regulation of Utility Operations:
IPC follows SFAS 71, "Accounting for the Effects of Certain Types of Regulation," and its financial statements reflect the effects of the different rate-making principles followed by the jurisdictions regulating IPC. The economic effects of regulation can result in regulated companies recording costs that have been, or are expected to be, allowed in the rate-making process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets on the balance sheet and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers.

11. Comprehensive Income:
Comprehensive income includes net income, unrealized holding gains and losses on marketable securities, IPC's proportionate share of unrealized holding gains and losses on marketable securities held by an equity investee and the changes in additional minimum liability under a deferred compensation plan for certain senior management employees and directors. The following table presents IPC's accumulated other comprehensive loss balance at December 31:

	2005	2004
	(thousands of dollars)	
Unrealized holding gains on securities	$ 2,725	$ 4,538
Minimum pension liability adjustment	(6,150)	(5,426)
Total	$ (3,425)	$ (888)

12. New Accounting Pronouncements:
SFAS 123(R): In December 2004, the FASB issued SFAS 123 (revised 2004), "Share-Based Payments," which revises SFAS 123 and supersedes APB 25 and its related interpretive guidance. SFAS 123(R) establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS 123(R) focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions.

Under the provisions of SFAS 123(R), the fair value of all stock options must be reported as an expense on the financial statements. IDACORP and IPC currently apply the measurement provisions of APB 25 and the disclosure-only provisions of SFAS 123. SFAS 123(R) also changes other measurement, timing and disclosure rules relating to share-based payments.

In March 2005, the staff of the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) 107 to provide additional guidance regarding the application of SFAS 123(R). SAB 107 permits registrants to choose an appropriate valuation technique or model to estimate the fair value of share options, assuming consistent application, and provides guidance for the development of assumptions used in the valuation process. Additionally, SAB 107 discusses disclosures to be made under "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the registrants' periodic reports.

Based upon Securities and Exchange Commission rules issued in April 2005, SFAS 123(R) is effective for fiscal years that begin after June 15, 2005 and will be adopted by IDACORP and IPC in the first quarter of 2006. Adoption is not expected to have a material effect on IDACORP's or IPC's financial statements.

SFAS 153: In December 2004, the FASB issued SFAS 153, "Exchanges of Nonmonetary Assets," which amends existing guidance on accounting for nonmonetary transactions. SFAS 153 is effective for exchanges occurring in fiscal periods beginning after June 15, 2005, and is not expected to have a material effect on IDACORP's or IPC's financial statements.

SFAS 154: In May 2005 the FASB issued SFAS 154, "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3." SFAS 154 changes the requirements for the accounting for and reporting of a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement that does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS 154 requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. When it is impracticable to determine the period-specific effects of an accounting change on one or more individual prior periods presented, SFAS 154 requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings for that period rather than being reported in an income statement. When it is impracticable to determine the cumulative effect of applying a change in accounting principle to all prior periods, SFAS 154 requires that the new accounting principle be applied as if it were adopted prospectively from the earliest date practicable. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

13. Other Accounting Policies:
    Debt discount, expense and premium are being amortized over the terms of the respective debt issues.

14. Reclassifications:
    Certain items previously reported for years prior to 2005 have been reclassified to conform to the current year's presentation. Net income and shareholders' equity were not affected by these reclassifications.

15. Financing:
    On October 22, 2003, Humboldt County, Nevada issued, for the benefit of IPC, $49.8 million Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2003 due December 1, 2024. IPC borrowed the proceeds from the issuance pursuant to a Loan Agreement with Humboldt County and is responsible for payment of principal, premium, if any, and interest on the bonds. The bonds are secured, as to principal and interest, by IPC first mortgage bonds and as to principal and interest when due, by an insurance policy issued by Ambac Assurance Corporation. The bonds were issued in an auction rate mode under which the interest rate is reset every 35 days. The initial auction rate was set at 0.95 percent. At December 31, 2005, the auction rate was 3.15 percent. Proceeds from this issuance together with other funds provided by IPC were used to redeem the outstanding $49.8 million Pollution Control Revenue Bonds (Idaho Power Company Project) 8.3% Series 1984 due 2014, on December 1, 2003, at 103 percent.

On March 14, 2003, IPC filed a $300 million shelf registration statement that could be used for first mortgage bonds (including medium-term notes), unsecured debt and preferred stock. On May 8, 2003, IPC issued $140 million of secured medium-term notes in two series: $70 million First Mortgage Bonds 4.25% Series due 2013 and $70 million First Mortgage Bonds 5.50% Series due 2033. Proceeds were used to pay down IPC short-term borrowings incurred from the payment at maturity of $80 million First Mortgage Bonds 6.40% Series due 2003 and the early redemption of $80 million First Mortgage Bonds 7.50% Series due 2023, on May 1, 2003. On March 26, 2004, IPC issued $50 million First Mortgage Bonds 5.50% Series due 2034. Proceeds were used to reduce short-term borrowings and replace short-term investments, which were used on March 15, 2004 to pay at maturity the $50 million First Mortgage Bonds 8% Series due 2004. On August 16, 2004, IPC issued $55 million First Mortgage Bonds 5.875% Series due 2034. On September 20, 2004, the proceeds of this issuance were used to redeem all of IPC's outstanding preferred stock.

On January 19, 2005, IPC filed a $245 million shelf registration statement that could be used for first mortgage bonds (including medium-term notes) and debt securities, and when combined with the $55 million remaining from the March 14, 2003 shelf registration, provided for $300 million available in shelf registration form. On August 26, 2005 IPC issued $60 million First Mortgage Bonds 5.30% Series due 2035. Proceeds were invested in short-term investments, which were used on September 9, 2005 to pay at maturity the $60 million First Mortgage Bonds 5.83% Series due 2005. At December 31, 2005, $240 million remained available to be issued on this shelf registration statement.

On August 17, 2004, IPC redeemed all $1 million of its Rural Electrification Administration notes.

At December 31, 2005 and 2004, the overall effective cost of all of IPC's outstanding debt was 5.84 percent and 5.69 percent, respectively.

The amount of first mortgage bonds issuable by IPC is limited to a maximum of $1.1 billion and by property, earnings and other provisions of the mortgage and supplemental indentures thereto. IPC may amend the indenture and increase this amount without consent of the holders of the first mortgage bonds. Substantially all of the electric utility plant is subject to the lien of the mortgage. As of December 31, 2005, IPC could issue under the mortgage approximately $560 million of additional first mortgage bonds based on unfunded property additions and $452 million of additional first mortgage bonds based on retired first mortgage bonds. At December 31, 2005, unfunded property additions, which consist of electric property, were approximately $933 million.

At December 31, 2005, IPC had regulatory authority to incur up to $250 million of short-term indebtedness. IPC has a $200 million credit facility that expires on March 31, 2010. Under this facility IPC pays a facility fee on the commitment, quarterly in arrears, based on its rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody's and S&P. IPC's commercial paper may be issued up to the amounts supported by the bank credit facilities. There was no commercial paper outstanding at December 31, 2005 or 2004.

16. Fair Value of Financial Instruments:

The estimated fair value of IPC's financial instruments has been determined using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts.

Cash and cash equivalents, customer and other receivables, notes payable, accounts payable, interest accrued and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for notes receivable, long-term debt and investments are based upon quoted market prices of the same or similar issues or discounted cash flow analyses as appropriate.

	December 31, 2005		December 31, 2004	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value

	(thousands of dollars)			
Assets:				
Notes receivable	$ 7,047	$ 6,876	$ 8,946	$ 8,877
Investments	21,137	21,137	53,155	53,155
Liabilities:				
Long-term debt	$ 987,045	$ 1,003,651	$ 987,045	$ 1,008,369

17. <u>Benefit Plans:</u>

Pension Plans

IPC has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee's final average earnings. IPC's policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. IPC was not required to contribute to the plan in 2005, 2004 or 2003, and does not expect to make a contribution in 2006. The market-related value of assets for the plan is equal to market value.

In addition, IPC has a nonqualified, deferred compensation plan for certain senior management employees and directors. This plan was financed by purchasing life insurance policies and investments in marketable securities, all of which are held by a trustee. The cash value of the policies and investments exceed the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

IPC uses a December 31 measurement date for its plans.

The following table summarizes the changes in benefit obligations and plan assets of these plans:

	Pension Plan		Deferred Compensation Plan	
	2005	2004	2005	2004
	(thousands of dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 374,333	$ 339,121	$ 38,645	$ 38,870
Service cost	13,129	11,809	1,170	1,358
Interest cost	21,126	20,437	2,151	2,312
Actuarial loss (gain)	11,399	16,626	2,799	(1,225)
Benefits paid	(13,938)	(13,660)	(2,312)	(2,670)
Plan amendments	-	-	270	-
Benefit obligation at December 31	406,049	374,333	42,723	38,645
Change in plan assets:				
Fair value at January 1	356,217	335,229	-	-
Actual return on plan assets	25,774	34,648	-	-
Employer contributions	-	-	-	-
Benefit payments	(13,938)	(13,660)	-	-
Fair value at December 31	368,053	356,217	-	-
Funded status	(37,996)	(18,116)	(42,723)	(38,645)
Unrecognized actuarial loss	43,806	28,491	13,553	11,443
Unrecognized prior service cost	5,118	5,889	1,414	1,372
Unrecognized net transition liability	-	(126)	-	310
Net amount recognized	$ 10,928	$ 16,138	$ (27,756)	$ (25,520)
Amounts recognized in the statement of financial position consist of:				
Prepaid (accrued) pension cost	$ 10,928	$ 16,138	$ (39,268)	$ (36,110)

Intangible asset	-	-	1,414	1,682
Accumulated other comprehensive income	-	-	10,098	8,908
Net amount recognized	$ 10,928	$ 16,138	$ (27,756)	$ (25,520)
Accumulated benefit obligation	$ 340,007	$ 316,498	$ 39,268	$ 36,110

The following table shows the components of net periodic benefit cost for these plans:

	Pension Plan			Deferred Compensation Plan		
	2005	2004	2003	2005	2004	2003
	(thousands of dollars)					
Service cost	$ 13,129	$ 11,809	$ 10,173	$ 1,170	$ 1,358	$ 1,212
Interest cost	21,126	20,437	19,463	2,151	2,312	2,414
Expected return on assets	(29,690)	(27,935)	(23,445)	-	-	-
Recognized net actuarial loss	-	-	361	689	878	744
Amortization of prior service cost	771	770	729	228	(361)	(345)
Amortization of transition asset	(126)	(263)	(263)	310	613	613
Net periodic pension cost (benefit)	$ 5,210	$ 4,818	$ 7,018	$ 4,548	$ 4,800	$ 4,638

Changes in the Deferred Compensation Plan minimum liability decreased other comprehensive income by $1 million in 2005, increased other comprehensive income by $1 million in 2004 and decreased other comprehensive income by $1 million in 2003.

The following table summarizes the expected future benefit payments of these plans:

	2006	2007	2008	2009	2010	2011-2015
Pension Plan	$ 14,277	$ 14,885	$ 15,988	$ 17,233	$ 18,701	$ 120,589
Deferred Compensation Plan	$ 2,165	$ 2,233	$ 2,629	$ 2,911	$ 3,092	$ 16,653

Plan Asset Allocations: IPC's pension plan and postretirement benefit plan weighted average asset allocations at December 31, 2004 and 2003, by asset category are as follows:

	Pension Plan		Postretirement Benefits	
Asset Category	2005	2004	2005	2004
Equity securities	66%	69%	-%	-%
Debt securities	21	21	-	3
Real estate	10	9	-	-
Other (a)	3	1	100	97
Total	100%	100%	100%	100%

(a) The postretirement benefit plan assets are primarily life insurance contracts.

Pension Asset Allocation Policy: The target allocations for the portfolio by asset class are as follows:

Large-Cap Growth Stocks	12%	International Growth Stocks	7%
Large-Cap Core Stocks	12%	International Value Stocks	7%
Large-Cap Value Stocks	12%	Intermediate-Term Bonds	13%
Small-Cap Growth Stocks	7%	Short-Term Bonds	10%
Small-Cap Value Stocks	7%	Core Real Estate	9%
Cash and Cash Equivalents	3%	Venture Capital	1%

Assets are rebalanced as necessary to keep the portfolio close to target allocations.

The plan's principal investment objective is to maximize total return (defined as the sum of realized interest and dividend income and realized and unrealized gain or loss in market price) consistent with prudent parameters of risk and the liability profile of the portfolio. Emphasis is placed on preservation and growth of capital along with adequacy of cash flow sufficient to fund current and future payments to pensioners.

There are three major goals in IPC's asset allocation process:

- Determine if the investments have the potential to earn the rate of return assumed in the actuarial liability calculations.
- Match the cash flow needs of the plan. IPC sets cash allocations sufficient to cover the current year benefit payments and bond allocations sufficient to cover at least five years of benefit payments. IPC then utilizes growth instruments (equities, real estate, venture capital) to fund the longer-term liabilities of the plan.
- Maintain a prudent risk profile consistent with ERISA fiduciary standards.

Allowable plan investments include stocks and stock funds, investment-grade bonds and bond funds, core real estate funds, private equity funds, and cash and cash equivalents. With the exception of real estate holdings and private equity, investments must be readily marketable so that an entire holding can be disposed of quickly with only a minor effect upon market price. Uncovered options, short sales, margin purchases, letter stock and commodities are prohibited.

Rate-of-return projections for plan assets are based on historical risk/return relationships among assets classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year US Treasury Notes. This historical risk premium is then added to the current yield on 10-year US Treasury Notes, and the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst–case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

IPC's asset modeling process also utilizes historical market returns to measure the portfolio's exposure to a "worst-case" market scenario, to determine how much performance could vary from the expected "average" performance over various time periods. This "worst-case" modeling, in addition to cash flow matching and diversification by asset class and investment style, provides the basis for managing the risk associated with investing portfolio assets.

Postretirement Benefits

IPC maintains a defined benefit postretirement plan (consisting of health care and death benefits) that covers all employees who were enrolled in the active group plan at the time of retirement as well as their spouses and qualifying dependents. Effective January 1, 2003, IPC amended its postretirement benefit plan. The amendment affects all employees who retire after December 31, 2002, limiting their postretirement benefit to a fixed amount. This amendment will limit the growth of IPC's future obligations under this plan.

The net periodic postretirement benefit cost was as follows (in thousands of dollars):

	2005	2004	2003
Service cost	$ 1,392	$ 1,400	$ 1,207
Interest cost	3,381	3,974	4,017
Expected return on plan assets	(2,486)	(2,294)	(1,930)
Amortization of unrecognized transition obligation	2,040	2,040	2,040
Amortization of prior service cost	(535)	(523)	(563)
Recognized actuarial loss	754	1,489	1,402
Net periodic postretirement benefit cost	$ 4,546	$ 6,086	$ 6,173

The following table summarizes the changes in benefit obligation and plan assets (in thousands of dollars):

	2005	2004
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 71,105	$ 67,090
Service cost	1,392	1,400
Interest cost	3,381	3,974
Actuarial loss	(9,186)	2,201
Benefits paid	(2,934)	(3,997)
Plan Amendments	(125)	437
Benefit obligation at December 31	63,633	71,105
Change in plan assets:		
Fair value of plan assets at January 1	29,723	26,603
Actual return on plan assets	1,127	2,301
Employer contributions	800	4,577
Benefits paid	(1,757)	(3,758)
Fair value of plan assets at December 31	29,893	29,723
Funded status	(33,740)	(41,382)
Unrecognized prior service cost	(3,677)	(4,087)
Unrecognized actuarial loss	15,978	24,559
Unrecognized transition obligation	14,280	16,320
Accrued benefit obligations included with other deferred credits	$ (7,159)	$ (4,590)

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law in December 2003 and establishes a prescription drug benefit, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.

The measures of accumulated postretirement benefit obligation at December 31, 2004 and net periodic benefit cost for the years ended December 31, 2004 and 2003 do not reflect any amount associated with the subsidy, because IPC initially determined that the effect of the Medicare Act would not be material. Regulations published on January 28, 2005 provided more flexibility in determining actuarial equivalence to Medicare of the benefits provided by the plan than was initially estimated by IPC's actuaries. Based on these new regulations, the effect of the Medicare Act is a reduction for IPC of $6 million to the accumulated postretirement benefit obligation at December 31, 2005 and $1 million to the 2005 periodic postretirement benefit cost.

The following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2006	2007	2008	2009	2010	2011-2015
Expected benefit payments*	$ 4,000	$ 4,200	$ 4,300	$ 4,400	$ 4,600	$ 25,100
Expected Medicare Part D subsidy receipts	$ 480	$ 488	$ 503	$ 518	$ 530	$ 2,936

The assumed health care cost trend rate used to measure the expected cost of benefits covered by the plan was 6.75 percent in 2005 and 2004. A one-percentage point change in the assumed health care cost trend rate would have the following effect (in thousands of dollars):

	1-Percentage-Point increase	decrease
Effect on total of cost components	$ 242	$ (184)
Effect on accumulated postretirement benefit obligation	$ 2,397	$ (1,900)

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all IPC-sponsored pension and postretirement benefits plans:

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.6%	5.75%	5.6%	5.75%
Expected long-term rate of return on assets	8.5	8.5	8.5	8.5
Rate of compensation increase	4.5	4.5	-	-
Medical trend rate	-	-	6.75	6.75
Expected working lifetime (years)	-	-	11	11

The following table sets forth the weighted-average assumptions used for the end of each year to determine net periodic benefit cost for all IPC-sponsored pension and postretirement benefit plans:

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.75%	6.15%	5.75%	6.15%
Expected long-term rate of return on assets	8.5	8.5	8.5	8.5
Rate of compensation increase	4.5	4.5	-	-
Medical trend rate	-	-	6.75	6.75
Expected working lifetime (years)	-	-	11	11

Employee Savings Plan
IPC has an Employee Savings Plan that complies with Section 401(k) of the Internal Revenue Code and covers substantially all employees. IPC matches specified percentages of employee contributions to the plan. Matching contributions amounted to $4 million in 2005 and $3 million in both 2004 and 2003.

Postemployment Benefits
IPC provides certain benefits to former or inactive employees, their beneficiaries and covered dependents after employment but before retirement. These benefits include salary continuation,

health care and life insurance for those employees found to be disabled under IPC's disability plans and health care for surviving spouses and dependents. IPC accrues a liability for such benefits. In accordance with an IPUC order, the portion of the liability attributable to regulated activities in Idaho as of December 31, 1993, was deferred as a regulatory asset, and amortized over a ten-year period, which ended in January 2005.

The following table summarizes postemployment benefit amounts included in IPC's consolidated balance sheets at December 31 (in thousands of dollars):

	2005	2004
Included with regulatory assets	$ -	$ 31
Included with other deferred credits	$ 3,845	$ 3,924

18. Property Plant and Equipment and Jointly-Owned Projects:

The following table presents the major classifications of IPC's utility plant in service, annual depreciation provisions as a percent of average depreciable balance and accumulated provision for depreciation for the years 2005 and 2004 (in thousands of dollars):

	2004		2003	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 1,563,008	2.54%	$ 1,482,517	2.51%
Transmission	580,382	2.19	560,303	2.18
Distribution	1,046,880	2.62	992,248	2.59
General and Other	286,797	8.94	289,748	10.02
Total in service	3,477,067	2.91%	3,324,816	2.96%
Accumulated provision for depreciation	(1,364,640)		(1,316,125)	
In service - net	$ 2,112,427		$ 2,008,691	

IPC has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. IPC's proportionate share of direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income. These facilities, and the extent of IPC's participation, were as follows at December 31, 2005 (in thousands of dollars):

Name of Plant	Location	Utility Plant In Service	Construction Work in Progress	Accumulated Provision for Depreciation	%	MW
Jim Bridger Units 1-4	Rock Springs, WY	$ 462,240	$ 5,148	$ 265,641	33	707
Boardman	Boardman, OR	69,385	454	46,160	10	59
Valmy Units 1 and 2	Winnemucca, NV	311,993	4,042	193,920	50	261

IPC's wholly owned subsidiary, Idaho Energy Resources Co., is a joint venturer in Bridger Coal Company, which operates the mine supplying coal to the Jim Bridger generating plant. Coal purchased by IPC from the joint venture amounted to $43 million, $47 million and $44 million in 2005, 2004 and 2003, respectively.

IPC has contracts to purchase the energy from four Public Utilities Regulatory Policy Act of 1978 (PURPA) Qualified Facilities that are 50 percent owned by Ida-West. Power purchased from these facilities amounted to $7 million annually in 2005, 2004 and 2003.

19. Regulatory Issues:

Idaho General Rate Case

IPC filed a general rate case in October 2005, requesting the IPUC to approve an annual increase to its Idaho retail base rates of $44 million or 7.8 percent. Base rates primarily reflect IPC's cost of providing electrical service to its customers, including equipment, vehicles and infrastructure.

On February 27, 2006, IPC, the IPUC staff and representatives of customer groups filed a proposed stipulation with the IPUC that, if approved, would settle this case. The stipulation calls for an $18.1 million increase, or 3.2 percent in IPC's annual electric rates. If approved by the IPUC, the changes in rates are expected to become effective on June 1, 2006.

The rate case filing was made with six months of actual operating expenses and six months of projected expenses. The agreed to increase in rates was lower than the requested amount primarily due to three factors: (1) 2005 actual numbers were significantly less than those forecasted; (2) the overall rate of return agreed to was 8.1 percent compared to the 8.42 percent IPC requested (no specific return on equity was determined); and (3) net power supply costs were kept at levels currently existing in rates. As a result of the settlement, IPC's overall rate of return will increase from the 7.85 percent currently authorized.

Oregon Rate Case
On September 21, 2004, IPC filed an application with the Oregon Public Utility Commission (OPUC) to increase general rates an average of 17.5 percent or approximately $4.4 million annually.

The OPUC issued its order on July 29, 2005 authorizing an increase of $0.6 million in annual revenues, an average of 2.37 percent. The significant decrease from IPC's requested amount was primarily related to differences in net power supply costs, which reduced IPC's initial rate request of $4.4 million by $2.4 million.

On September 26, 2005, IPC filed a complaint with the Circuit Court of Marion County, Oregon asking the court to reverse the portion of the OPUC's general rate case order related to the determination of net power supply costs.

Deferred Power Supply Costs
IPC's deferred net power supply costs consisted of the following at December 31 (in thousands of dollars):

	2005	2004
Idaho PCA current year:		
Deferral for the 2005-2006 rate year	$ -	$ 22,778
Deferral for the 2006-2007 rate year	3,684	-
Irrigation Lost Revenues	-	13,290
Idaho PCA true-up awaiting recovery:		
Authorized May 2004	-	11,415
Authorized May 2005*	28,567	-
Oregon deferral:		
2001 costs	8,411	12,047
2005 costs	2,880	-
Total deferral	$ 43,542	$ 59,530

*$28 million will be recovered with interest during the 2006-2007 PCA rate year.

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered portions, is then included in the calculation of the next year's PCA.

On April 15, 2005, IPC filed the 2005-2006 PCA with the IPUC with a proposed effective date of June 1, 2005. The application proposed to hold the PCA component of customers' rates at the existing level, which is currently recovering $71 million above base rates. By IPUC order, the 2005 - 2006 PCA includes $12 million in lost revenues and $2 million in related interest resulting from IPC's Irrigation Load Reduction Program that was in place in 2001. IPC proposed to defer recovery of approximately $28 million of power supply costs, or 4.75 percent, for one year to help mitigate the impacts of the increases for the Bennett Mountain Power Plant and the rate case tax settlement adjustments, since all three were proposed to be effective June 1, 2005. The $28 million will be recovered during the 2006-2007 PCA rate year, and IPC will earn a two percent carrying charge on this balance. The IPUC accepted the company's PCA proposal.

On April 15, 2004, IPC filed its 2004-2005 PCA with the IPUC requesting recovery of $71 million above base rates and a proposed effective date of June 1, 2004. On May 25, 2004, the IPUC issued Order No. 29506 approving IPC's filing.

On May 15, 2003, the IPUC issued Order No. 29243 approving IPC's 2003-2004 PCA filing, with a small adjustment to the original filing. As approved, IPC's rates were adjusted to collect $81 million above 1993 base rates.

On April 15, 2002, the IPUC issued Order No. 28992 disallowing recovery of $12 million of lost revenues resulting from the Irrigation Load Reduction Program that was in place in 2001. IPC believed that this IPUC order was inconsistent with Order No. 28699, dated May 25, 2001, that allowed recovery of such costs, and IPC filed a Petition for Reconsideration on May 2, 2002. On August 29, 2002, the IPUC issued Order No. 29103 denying the Petition for Reconsideration. As a result of this order, approximately $12 million was expensed in September 2002. IPC believed it was entitled to recover this amount and argued its position before the Idaho Supreme Court on December 5, 2003. On March 30, 2004, the Idaho Supreme Court set aside the IPUC denial of the recovery of lost revenues and remanded the matter to the IPUC to determine the amount of lost revenues to be recovered. On December 29, 2004, the IPUC issued Order No. 29669 allowing IPC to recover $12 million in lost revenues and $2 million in interest. The recovery was included as part of IPC's annual PCA beginning June 1, 2005.

Oregon: On March 2, 2005 IPC filed for an accounting order to defer net power supply costs for the period of March 1, 2005 through February 28, 2006 in anticipation of continued low water conditions. The forecasted net system power supply costs included in this filing was $169 million, of which $3 million related to the Oregon jurisdiction. IPC is proposing to use the same methodology for this deferral filing that was accepted in 2002 for Oregon's share of IPC's 2001 net power supply expenses. On July 1, 2005, IPC, the OPUC staff and the Citizen's Utility Board entered into a stipulation requesting that the OPUC accept IPC's proposed methodology. Under this methodology, IPC will earn its Oregon authorized rate of return on the deferred balance and will recover the amount through rates in future years, as approved by the OPUC.

IPC is also recovering calendar year 2001 excess power supply costs applicable to the Oregon jurisdiction. In two separate 2001 orders, the OPUC approved rate increases totaling six percent, which was the maximum annual rate of recovery allowed under Oregon state law at that time. These increases were recovering approximately $2 million annually. During the 2003 Oregon legislative session, the maximum annual rate of recovery was raised to ten percent under certain circumstances. IPC requested and received authority to increase the surcharge to ten percent. As a result of the increased recovery rate, which became effective on April 9, 2004, IPC is recovering approximately $3 million annually.

Fixed-Cost Adjustment Mechanism

On January 27, 2006, IPC filed with the IPUC for authority to implement a rate adjustment mechanism which would adjust IPC's rates upward or downward to recover IPC's fixed costs independent from the volume of IPC's energy sales. The filing is a continuation of an Idaho case opened in 2004 to investigate the financial disincentives to investment in energy efficiency by IPC. The true-up mechanism, entitled "fixed-cost adjustment" (FCA) would be applicable only to residential service and small general service customers.

The fixed-cost recovery portion of IPC's revenue requirement allowed for recovery in rates would be established for these two customer classes at the time of a general rate case. Thereafter, the FCA would provide a mechanism to true-up the collection of fixed costs to recover the difference between the fixed costs actually recovered through rates and the fixed costs that were allowed to be recovered. Accounting for the FCA would be effective as of January 1, 2006, and the first FCA rate change would occur on June 1, 2007.

The FCA is proposed to change rates coincidentally with IPC's Power Cost Adjustment (PCA) and IPC's seasonal rates. Although the FCA would be timed to adjust on the same schedule as the PCA, the accounting for the FCA would be separate from the PCA. Additionally, IPC proposes to include a three percent cap on any FCA filing, to be applied at the discretion of the IPUC.

Regulatory Assets and Liabilities

The following is a breakdown of IPC's regulatory assets and liabilities (in thousands of dollars):

	As of December 31, 2005					
Description	Remaining Amortization Period	Earning a Return	Not Earning a Return	Pending Regulatory Treatment	2005 Total	As of December 31, 2004 Total
Regulatory Assets:						
Income Taxes		$ -	$ 346,117	$ -	$ 346,117	$ 344,220
Conservation	2010	14,592	-	-	14,592	17,836
PCA Deferral	2007	32,251	-	-	32,251	34,193
Oregon Deferral(1)		11,291	-	-	11,291	12,047
Asset Retirement Obligations		-	8,363	-	8,363	8,372
Tax Settlement Order	2006	4,994	-	-	4,994	7,119
Irrigation Lost Revenues (2)	2007	-	-	-	-	13,290
Incremental Security Costs	2008	575	-	-	575	813
Other	Various thru 2007	41	17	-	58	891
Total		$ 63,744	$ 354,497	$ -	$ 418,241	$ 438,781
Regulatory Liabilities:						
Income Taxes		$ -	$ 41,627	$ -	$ 41,627	$ 40,447
Conservation	2007	6,535	-	-	6,535	5,205
Asset Retirement Obligations		-	152,683	-	152,683	147,700
Deferred ITC		-	68,786	-	68,786	66,836
IPUC Settlement Order	2006	4,021	-	-	4,021	13,671
BPA Settlement	2006	1,393	-	-	1,393	1,833
OPUC Settlement		-	-	-	-	100
Emission Allowance		-	-	70,034	70,034	-
Other	Various thru 2007	30	-	-	30	62
Total		$ 11,979	$ 263,096	$ 70,034	$ 345,109	$ 275,854

(1) Capped at 10 percent increase per year.
(2) Included in PCA amortization balance.

For further information on the asset retirement obligations amounts, see Note 21.

In the event that recovery of costs through rates becomes unlikely or uncertain, SFAS 71 would no longer apply. If IPC were to discontinue application of SFAS 71 for some or all of its operations, then these items may represent stranded investments. If IPC is not allowed recovery of these investments, it would be required to write off the applicable portion of regulatory assets and the financial effects could be significant.

20. Investments:

The following table summarizes IPC's investments as of December 31 (in thousands of dollars):

	2005	2004
IPC Investments:		
Auction rate securities (available-for-sale)	$ -	$ 31,650
Equity method investment	38,764	25,028
Available-for-sale equity securities	21,137	21,505
Executive deferred compensation	6,201	6,002
Other investments	1,025	808
Total IPC investments	$ 84,993	$ 84,993

Equity Method Investments

IPC, through its subsidiary Idaho Energy Resources Co., is a 33 percent owner of Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

The following table presents IPC's earnings of unconsolidated equity-method investments (in thousands of dollars):

	2005	2004	2003
Bridger Coal Company (IPC)	$ 10,369	$ 12,313	$ 11,336

Investments in Debt and Equity Securities

Investments in debt and equity securities are accounted for in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Those investments classified as available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income.

IPC held $32 million of auction rate securities at December 31, 2004. Auction rate securities are long-term instruments whose interest rates or dividends are reset at specific frequencies. The typical reset periods are either 28 or 35 days. The rates or dividends are reset via a Dutch auction. The original maturities of these securities at the time of issuance ranged from 2007 to 2042. IPC did not hold any auction rate securities at December 31, 2005.

The following table summarizes investments in debt and equity securities (in thousands of dollars):

	2005			2004		
	Gross Unrealizec Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities (IPC)	$ 2,925	$ 497	$ 21,137	$ 2,530	$ 256	$ 53,155

The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2005	2004	2003
Proceeds from sales	$ 120,026	$ 266,331	$ 14,040
Gross realized gains from sales	2,850	2,044	1,046
Gross realized losses from sales	643	634	1,169

Additionally, these investments are evaluated to determine whether they have experienced a decline in market value that is considered other-than-temporary. IPC analyzes securities in loss positions as of the end of each reporting period. Any security with an unrealized loss of more than 20 percent is evaluated for other-than-temporary impairment. A security will generally be written down to market value if it has an unrealized loss of 20 percent or more for more than nine months. If additional information is available that indicates a security is other-than-temporarily impaired, it will be written down prior to the nine-month time period. In the alternative, if a security has been impaired for more than nine months but available information indicates that the impairment is temporary, the security will not be written down. IPC recognized an other-than-temporary impairment of $0.6 million in 2003. In 2005 and 2004, there were no other-than-temporary declines in market value.

The following table summarizes information regarding securities that were in an unrealized loss position at the end of each year, but for which no other-than-temporary impairment was recognized (in thousands of dollars).

	Aggregate Unrealized Loss	Aggregate Related Fair Value	Aggregate Unrealized Loss	Aggregate Related Fair Value
	Less than 12 months		12 months or longer	
2005:				
Available for sale equity securities	$ 215	$ 1,731	$ 282	$ 1,423
2004:				
Available for sale equity securities	$ 181	$ 2,934	$ 75	$ 362

The available-for-sale equity securities in unrealized loss positions are diversified investments in common stock of various companies used to fund IPC's Senior Management Security Plan. At December 31, 2005, nine available-for-sale securities were in an unrealized loss position. At December 31, 2004, ten available-for-sale securities were in an unrealized loss position. At December 31, 2005 two available-for-sale securities had unrealized loss positions of greater than 20 percent. Both securities exceeded 20 percent for fewer than nine months. IPC does not consider these investments to be other-than-temporarily impaired at December 31, 2005 or 2004.

21. <u>Asset Retirement Obligations:</u>

On January 1, 2003, IPC adopted SFAS 143, "Accounting for Asset Retirement Obligations." This statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. An obligation may result from the acquisition, construction, development or the normal operation of a long-lived asset. SFAS 143 requires an entity to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized at that time. As a rate-regulated entity, IPC records regulatory assets and liabilities instead of accretion, depreciation and gains or losses. This treatment was approved by Order No. 29414 from the IPUC. The regulatory assets recorded under this order do not earn a return on investment.

In 2005, IPC adopted FIN 47. This Interpretation clarifies that the term "conditional asset retirement obligation," as used in FASB Statement No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional ARO should be recognized when incurred-generally upon acquisition, construction, or development and/or through the normal operation of the asset. Uncertainty about the timing and/or method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. FAS 143 acknowledges that, in some cases, sufficient information may not be available to reasonably estimate the fair value of an ARO. The Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

FIN 47 became effective December 31, 2005. After reviewing the provisions of FIN 47, no significant additional AROs were identified at IPC.

The regulated operations of IPC also collect removal costs in rates for certain assets that do not have associated AROs. The adoption of SFAS 143 required IPC to redesignate these removal costs as regulatory liabilities. As of December 31, 2005, IPC had $153 million of such costs recorded as regulatory liabilities on its Consolidated Balance Sheet.

The following table presents the changes in the aggregate carrying amount of AROs (in thousands of dollars):

	2005	2004
Balance at beginning of year	$ 9,288	$ 7,140
Accretion expense	531	421
Revisions in estimated cash flows	260	1,727
Balance at end of year	$ 10,079	$ 9,288

ATTACHMENT I(b)

STATEMENT OF CAPITAL STOCK AND FUNDED DEBT

IDAHO POWER COMPANY

The following statement as to each class of the capital stock of applicant is as of December 31, 2005, the date of the balance sheet submitted with this application:

Common Stock

(1) Description - Common Stock, $2.50 par value; 1 vote per share
(2) Amount authorized - 50,000,000 shares ($125,000,000 par value)
(3) Amount outstanding - 39,150,812 shares
(4) Amount held as reacquired securities - None
(5) Amount pledged by applicant - None
(6) Amount owned by affiliated corporations – All
(7) Amount held in any fund - None

Applicant's Common Stock is held by IDACORP, Inc., the holding company of Idaho Power Company. IDACORP, Inc.'s Common Stock is registered (Pursuant to Section 12(b) of the Securities Exchange Act of 1934) and is listed on the New York Stock Exchange.

STATEMENT OF CAPITAL STOCK AND FUNDED DEBT (Continued)

IDAHO POWER COMPANY

The following statement as to funded debt of applicant is as of December 31, 2005, the date of the balance sheet submitted with this application.

First Mortgage Bonds

(1) Description	(3) Amount Outstanding
FIRST MORTGAGE BONDS:	
7.38 % Series due 2007, dated as of Dec 1, 2000, due Dec 1, 2007	80,000,000
7.20 % Series due 2009, dated as of Nov 23, 1999, due Dec 1, 2009	80,000,000
6.60 % Series due 2011, dated as of Mar 2, 2001, due Mar 2, 2011	120,000,000
4.75 % Series due 2012, dated as of Nov 15, 2002, due Nov 15, 2012	100,000,000
4.25 % Series due 2013, dated as of May 13, 2003, due October 1, 2013	70,000,000
6 % Series due 2032, dated as of Nov 15, 2002, due Nov 15, 2032	100,000,000
5.50 % Series due 2033, dated as of May 13, 2003, due April 1, 2033	70,000,000
5.50 % Series due 2034, dated as of March 26, 2004, due March 15, 2034	50,000,000
5.875%Series due 2034, dated as of August 16, 2004, due August 15, 2034	55,000,000
5.30 % Series due 2035, dated as of August 23, 2005, due August 15, 2035	60,000,000
	785,000,000

(2) Amount authorized - Limited within the maximum of $1,100,000,000 (or such other maximum amount as may be fixed by supplemental indenture) and by property, earnings, and other provisions of the Mortgage.
(4) Amount held as reacquired securities - None
(5) Amount pledged - None
(6) Amount owned by affiliated corporations - None
(7) Amount of sinking or other funds - None
(8) The Humboldt County Pollution Control Revenue bonds are secured by first mortgage bonds, bringing the total first mortgage bonds outstanding at December 31, 2005 to $834.8 million

For a full statement of the terms and provisions relating to the respective Series and amounts of applicant's outstanding First Mortgage Bonds above referred to, reference is made to the Mortgage and Deed of Trust dated as of October 1, 1937, and First to Fortieth Supplemental Indentures thereto, by Idaho Power Company to Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page (Stanley Burg, successor individual trustee), Trustees, presently on file with the Commission, under which said bonds were issued.

IDAHO POWER COMPANY

Pollution Control Revenue Bonds

(A) Variable Rate Series 2000 due 2027:
(1) Description - Pollution Control Revenue Bonds, Variable Rate Series 2000 due 2027, Port of Morrow, Oregon, dated as of May 17, 2000, due February 1, 2027.
(2) Amount authorized - $4,360,000
(3) Amount outstanding - $4,360,000
(4) Amount held as reacquired securities - None
(5) Amount pledged - None
(6) Amount owned by affiliated corporations - None
(7) Amount in sinking or other funds - None

(B) Variable Auction Rate Series 2003 due 2024:
(1) Description - Pollution Control Revenue Refunding Bonds, Variable Auction Rate Series 2003 due 2024, County of Humboldt, Nevada, dated as of October 22, 2003 due December 1, 2024 (secured by First Mortgage Bonds)
(2) Amount authorized - $49,800,000
(3) Amount outstanding - $49,800,000
(4) Amount held as reacquired securities - None
(5) Amount pledged - None
(6) Amount owned by affiliated corporations - None
(7) Amount in sinking or other funds - None

(C) 6.05% Series 1996A due 2026:
(1) Description - Pollution Control Revenue Refunding Bonds, 6.05% Series 1996A
due 2026, County of Sweetwater, Wyoming,
dated as of July 15, 1996, due July 15, 2026
(2) Amount authorized - $68,100,000
(3) Amount outstanding - $68,100,000
(4) Amount held as reacquired securities - None
(5) Amount pledged - None
(6) Amount owned by affiliated corporations - None
(7) Amount in sinking or other funds - None

(D) Variable Rate Series 1996B due 2026:
(1) Description - Pollution Control Revenue Refunding Bonds, Variable Rate 1996B
Series due 2026, County of Sweetwater, Wyoming, dated
as of July 15, 1996, due July 15, 2026.
(2) Amount authorized - $24,200,000
(3) Amount outstanding - $24,200,000
(4) Amount held as reacquired securities - None
(5) Amount pledged - None
(6) Amount owned by affiliated corporations - None
(7) Amount in sinking or other funds - None

IDAHO POWER COMPANY

Pollution Control Revenue Bonds

(E) Variable Rate Series 1996C due 2026:

(1) Description - Pollution Control Revenue Refunding Bonds, Variable Rate 1996C
Series due 2026, County of Sweetwater, Wyoming, dated as of July 15, 1996, due July 15, 2026.

(2) Amount authorized - $24,000,000

(3) Amount outstanding - $24,000,000

(4) Amount held as reacquired securities - None

(5) Amount pledged - None

(6) Amount owned by affiliated corporations - None

(7) Amount in sinking or other funds - None

For a full statement of the terms and provisions relating to the outstanding Pollution Control Revenue Bonds above referred to, reference is made to (A) copies of Trust Indenture by Port of Morrow, Oregon, to the Bank One Trust Company, N. A., Trustee, and Loan Agreement between Port of Morrow, Oregon and Idaho Power Company, both dated May 1, 2000, under which the Variable Rate Series 2000 bonds were issued, (B) copies of Loan Agreement between Idaho Power Company and Humboldt County, Nevada dated October 1, 2003; Trust Indenture between Humboldt County, Nevada and Union Bank of California dated October 1, 2003; Escrow Agreement among Humboldt County, Nevada, Bank One Trust Company and Idaho Power Company dated October 1, 2003; Purchase Contract dated October 21, 2003 among Humboldt County, Nevada, Idaho Power Company and Bankers Trust Company; Auction Agreement, dated as of October 22, 2003 among Idaho Power Company, Union Bank of California and Deutsche Bank Trust Company Americas; Insurance Agreement, dated as of October 1, 2003 between AMBAC Assurance Corporation, and Idaho Power Company; Broker-Dealer agreements dated October 22, 2003 among Deutsche Bank Trust Company Americas, Banc One Capital Markets, Banc of America Securities and Idaho Power Company, under which the Auction Rate Series 2003 bonds were issued, and (C) (D) (E) copies of Indentures of Trust by Sweetwater County, Wyoming, to the First National Bank of Chicago, Trustee, and Loan Agreements between Idaho Power Company and Sweetwater County, Wyoming, all dated July 15, 1996, under which the 6.05% Series 1996A bonds, Variable Rate Series 1996B bonds and Variable Rate Series 1996C bonds were issued.

ATTACHMENT I(c)

COMMITMENTS AND CONTINGENCIES:

As of December 31, 2005, Idaho Power Company (IPC) had agreements to purchase energy from 87 cogeneration and small power production (CSPP) facilities with contracts ranging from one to 30 years. Under these contracts IPC is required to purchase all of the output from the facilities inside the IPC service territory. For projects outside the IPC service territory, IPC is required to purchase the output that it has the ability to receive at the facility's requested point of delivery on the IPC system. IPC purchased 715,209 megawatt-hours (MWh) at a cost of $43 million in 2005, 677,868 MWh at a cost of $40 million in 2004 and 654,131 MWh at a cost of $38 million in 2003.

At December 31, 2005, IPC had the following long-term commitments relating to purchases of energy, capacity, transmission rights and fuel:

	2006	2007	2008	2009	2010	Thereafter
Cogeneration and small power production	$ 59,719	$70,283	$70,283	$73,753	$73,753	$1,039,377
Power and transmission rights	148,818	14,362	8,762	6,193	3,714	13,001
Fuel	43,370	40,496	26,997	18,013	12,010	10,118

IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Co., a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $60 million at December 31, 2005. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. Bridger Coal Company and IPC expect that the fund will be sufficient to cover all such costs. Because of the existence of the fund, the estimated fair value of this guarantee is minimal.

From time to time IPC is a party to legal claims, actions and complaints in addition to those discussed below. IPC believes that they have meritorious defenses to all lawsuits and legal proceedings. Although they will vigorously defend against them, they are unable to predict with certainty whether or not they will ultimately be successful. However, based on IPC's evaluation, IPC believes that the resolution of these matters, taking into account existing reserves, will not have a material adverse effect on its consolidated financial positions, results of operations or cash flows.

Legal Proceedings

Public Utility District No. 1 of Grays Harbor County, Washington: On October 15, 2002, Public Utility District No. 1 of Grays Harbor County, Washington (Grays Harbor) filed a lawsuit in the Superior Court of the State of Washington, for the County of Grays Harbor, against IDACORP, IPC and IDACORP Energy (IE). On March 9, 2001, Grays Harbor entered into a 20-megawatt (MW) purchase transaction with IPC for the purchase of electric power from October 1, 2001 through March 31, 2002, at a rate of $249 per MWh. In June 2001, with the consent of Grays Harbor, IPC assigned all of its rights and obligations under the contract to IE. In its lawsuit, Grays Harbor alleged that the assignment was void and unenforceable, and sought restitution from IE and IDACORP, or in the alternative, Grays Harbor alleged that the contract should be rescinded or reformed. Grays Harbor sought as damages an amount equal to the difference between $249 per MWh and the "fair value" of electric power delivered by IE during the period October 1, 2001 through March 31, 2002.

IDACORP, IPC and IE removed this action from the state court to the U.S. District Court for the Western District of Washington at Tacoma. On November 12, 2002, the companies filed a motion to dismiss Grays Harbor's complaint, asserting that the U.S. District Court lacked jurisdiction because the FERC has exclusive jurisdiction over wholesale power transactions and thus the matter is preempted under the Federal Power Act and barred by the filed-rate doctrine. The court ruled in favor of the companies' motion to dismiss and dismissed the case with prejudice on January 28, 2003. On February 25, 2003, Grays Harbor filed a Notice of Appeal, appealing the final judgment of dismissal to the U.S. Court of Appeals for the Ninth Circuit. On August 10, 2004, the Ninth Circuit affirmed the dismissal of Grays Harbor's complaint, finding that Grays Harbor's claims were preempted by federal law and were barred by the filed-rate doctrine. The court also remanded the case to allow Grays Harbor leave to amend its complaint to seek declaratory relief only as to contract formation, and held that Grays Harbor could seek monetary relief, if at all, only from the FERC, and not from the courts. IDACORP, IPC and IE sought rehearing from the Ninth Circuit arguing that the court erred in granting leave to amend the complaint as such a declaratory relief claim would be preempted and would be barred by the filed-rate doctrine. The Ninth Circuit denied the rehearing request on October 25, 2004, and the decision became final on November 12, 2004.

On that same date, the companies took steps to have the case transferred and consolidated with other similar cases arising out of the California energy crisis currently pending before the Honorable Robert H. Whaley, sitting by designation in the Southern District of California and presiding over Multidistrict Litigation Docket No. 1405, regarding California Wholesale Electricity Antitrust Litigation. On November 18, 2004, Grays Harbor filed an amended complaint alleging that the contract was formed under circumstances of "mistake" as to an "artificial . . . power shortage." Grays Harbor asked that the contract therefore be declared "unenforceable" and found "unconscionable." On December 23, 2004, the Judicial Panel on Multidistrict Litigation conditionally transferred the case to Judge Whaley. Grays Harbor sought to vacate the transfer; however, on April 18, 2005, the Judicial Panel on Multidistrict Litigation ordered the case transferred. On May 18, 2005, IDACORP, IPC and IE filed a motion to dismiss the amended complaint. The motion was heard on September 29, 2005.

On December 16, 2005, Judge Whaley issued an Order Setting Status Conference wherein, rather than expressly ruling on the companies' motion to dismiss Grays Harbor's amended complaint, he ruled that either Grays Harbor or the companies may, within 45 days of the date of the order, petition the FERC to weigh in on this case in light of "the extensive hearings . . . already undertaken by FERC in the Northwest refund proceeding" which may be relevant to this case. On January 27, 2006 Grays Harbor and the companies jointly filed a stipulation requesting that the court stay the action and extend the time in which the parties may petition the FERC by sixty days to March 31, 2006 stating that the parties felt the case was appropriate for mediation prior to further proceedings. On January 31, 2006 the court approved the stipulation staying the case until March 31, 2006 and setting a status conference for April 14, 2006. IPC intends to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Port of Seattle: On May 21, 2003, the Port of Seattle, a Washington municipal corporation, filed a lawsuit against 20 energy firms, including IPC and IDACORP, in the U.S. District Court for the Western District of Washington at Seattle. The Port of Seattle's complaint alleges fraud and violations of state and federal antitrust laws and the Racketeer Influenced and Corrupt Organizations Act. On December 4, 2003, the Judicial Panel on Multidistrict Litigation transferred the case to the Southern District of California for inclusion with several similar multidistrict actions currently pending before the Honorable Robert H. Whaley.

All defendants, including IPC and IDACORP, moved to dismiss the complaint in lieu of answering it. The motions were based on the ground that the complaint seeks to set alternative electrical rates, which are exclusively within the jurisdiction of the FERC and are barred by the filed-rate doctrine. A hearing on the motion to dismiss was heard on March 26, 2004. On May 28, 2004, the court granted IPC's and IDACORP's motion to dismiss. In June 2004, the Port of Seattle appealed the court's decision to the U.S. Court of Appeals for the Ninth Circuit. On July 19, 2005 the companies filed a motion for summary affirmance of the district court's order dismissing the Port of Seattle's complaint. The Ninth Circuit issued an order denying this motion on October 17, 2005. The appeal has been fully briefed; and oral argument has been scheduled for March 7, 2006. IPC intends to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Wah Chang: On May 5, 2004, Wah Chang, a division of TDY Industries, Inc., filed two lawsuits in the U.S. District Court for the District of Oregon against numerous defendants. IDACORP, IE and IPC are named as defendants in one of the lawsuits. The complaints allege violations of federal antitrust laws, violations of the Racketeer Influenced and Corrupt Organizations Act, violations of Oregon antitrust laws and wrongful interference with contracts. Wah Chang's complaint is based on allegations relating to the western energy situation. These allegations include bid rigging, falsely creating congestion and misrepresenting the source and destination of energy. The plaintiff seeks compensatory damages of $30 million and treble damages.

On September 8, 2004, this case was transferred and consolidated with other similar cases currently pending before the Honorable Robert H. Whaley. The companies' motion to dismiss the complaint was granted on February 11, 2005. Wah Chang appealed to the Ninth Circuit on March 10, 2005. The Ninth Circuit set a briefing schedule on the appeal, requiring Wah Chang's opening brief to be filed by July 6, 2005. On May 18, 2005, Wah Chang filed a motion to stay the appeal or in the alternative to voluntarily dismiss the appeal without prejudice to reinstatement. The companies opposed the motion and filed a cross-motion asking the Court to summarily affirm the district court's order of dismissal. On July 8, 2005, the Ninth Circuit denied Wah Chang's motion and also denied the companies' motion for summary affirmance without prejudice to renewal following the filing of Wah Chang's opening brief. Wah Chang's opening brief was filed on September 21, 2005. On October 11, 2005 the companies, along with the other defendants, filed a motion to consolidate this appeal with Wah Chang v. Duke Energy Trading and Marketing currently pending before the Ninth Circuit. On October 18, 2005 the Ninth Circuit granted the motion to consolidate and established a revised briefing schedule. The companies filed an answering brief on November 30, 2005. Wah Chang's reply brief was filed on January 6, 2006. The appeal has been fully briefed; however, no date has yet been set for oral argument. IPC intends to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

City of Tacoma: On June 7, 2004, the City of Tacoma, Washington filed a lawsuit in the U.S. District Court for the Western District of Washington at Tacoma against numerous defendants including IDACORP, IE and IPC. The City of Tacoma's complaint alleges violations of the Sherman Antitrust Act. The claimed antitrust violations are based on allegations of energy market manipulation, false load scheduling and bid rigging and misrepresentation or withholding of energy supply. The plaintiff seeks compensatory damages of not less than $175 million.

On September 8, 2004, this case was transferred and consolidated with other similar cases currently pending before the Honorable Robert H. Whaley. The companies' motion to dismiss the complaint was granted on February 11, 2005. The City of Tacoma appealed to the Ninth Circuit on March 10, 2005.

On August 9, 2005, the companies moved for summary affirmance of the district court's order dismissing the City of Tacoma's complaint. The City of Tacoma filed a response to the companies' motion for summary affirmance on August 24, 2005. The Ninth Circuit denied the companies' motion for summary affirmance on November 3, 2005. The appeal has been fully briefed; however, no date has yet been set for oral argument. IPC intends to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Wholesale Electricity Antitrust Cases I & II: These cross-actions against IE and IPC emerged from multiple California state court proceedings first initiated in late 2000 against various power generators/marketers by various California municipalities and citizens. Suit was filed against entities including Reliant Energy Services, Inc., Reliant Ormond Beach, L.L.C., Reliant Energy Etiwanda, L.L.C., Reliant Energy Ellwood, L.L.C., Reliant Energy Mandalay, L.L.C. and Reliant Energy Coolwater, L.L.C. (collectively, Reliant); and Duke Energy Trading and Marketing, L.L.C., Duke Energy Morro Bay, L.L.C., Duke Energy Moss Landing, L.L.C., Duke Energy South Bay, L.L.C. and Duke Energy Oakland, L.L.C. (collectively, Duke). While varying in some particulars, these cases made a common claim that Reliant, Duke and certain others (not including IE or IPC) colluded to influence the price of electricity in the California wholesale electricity market. The plaintiffs asserted various claims that the defendants violated the California Antitrust Law (the Cartwright Act), Business and Professions Code Section 16720 and California's Unfair Competition Law, Business and Professions Code Section 17200. Among the acts complained of are bid rigging, information exchanges, withholding of power and other wrongful acts. These actions were subsequently consolidated, resulting in the filing of Plaintiffs' Master Complaint in San

Diego Superior Court on March 8, 2002.

On April 22, 2002, more than a year after the initial complaints were filed, two of the original defendants, Duke and Reliant, filed separate cross-complaints against IPC and IE, and approximately 30 other cross-defendants. Duke and Reliant's cross-complaints sought indemnity from IPC, IE and the other cross-defendants for an unspecified share of any amounts they must pay in the underlying suits because, they allege, other market participants like IPC and IE engaged in the same conduct at issue in the Plaintiffs' Master Complaint. Duke and Reliant also sought declaratory relief as to the respective liability and conduct of each of the cross-defendants in the actions alleged in the Plaintiffs' Master Complaint. Reliant also asserted a claim against IPC for alleged violations of the California Unfair Competition Law, Business and Professions Code Section 17200. As a buyer of electricity in California, Reliant requested the same relief from the cross-defendants, including IPC, as that sought by plaintiffs in the Plaintiffs' Master Complaint as to any power Reliant purchased through the California markets.

Some of the newly added defendants (foreign citizens and federal agencies) removed that litigation to federal court. IPC and IE, together with numerous other defendants added by the cross-complaints, moved to dismiss these claims, and those motions were heard in September 2002, together with motions to remand the case back to state court filed by the original plaintiffs. On December 13, 2002, the U.S. District Court granted Plaintiffs' Motion to Remand to state court, but did not issue a ruling on IPC and IE's motion to dismiss. The U.S. Court of Appeals for the Ninth Circuit granted certain Defendants and Cross-Defendants' Motions to Stay the Remand Order while they appeal the order. The briefing on the appeal was completed in December 2003. On December 8, 2004, the Ninth Circuit issued its opinion in People of California v. NRG Energy, Inc., et al., which affirmed the district court's remand of these cases to state court and dismissed certain federal government defendants due to their sovereign immunity from suit.

On June 3, 2005, the cross-defendants, including IPC and IE, filed a demurrer in state court seeking to dismiss the cross-complaints filed by Duke and Reliant. On August 8, 2005, before that demurrer was to be heard, the Clerk of the Court entered Duke's voluntary dismissal, with prejudice, of the cross-complaint against IE and IPC. Further briefing and hearing on IE and IPC's demurrer to the Reliant cross-complaint was stayed pending the outcome of the demurrer filed by Reliant on the Master Complaint. On September 22, 2005, the Court took Reliant's demurrer off calendar pending approval of a proposed settlement as to the plaintiff's Master Complaint. On October 3, 2005 the court sustained the defendants' (other than Reliant's) joint demurrer to the Master Complaint and scheduled a status conference to discuss the status of the cross-complaints. On October 13, 2005 the court set IE and IPC's demurrer on the cross-complaint for hearing on December 23, 2005.

However, on November 14, 2005, Judge Joan M. Lewis approved a stipulation between the cross-defendants, including IE and IPC, and Reliant. This stipulation provided for dismissal of IE and IPC by Reliant with prejudice subject to reinstatement in the event that approval and finalization of a settlement agreement between Reliant and the underlying plaintiffs in these cases does not occur. The December 23, 2005 hearing on IE and IPC's demurrer to the cross-complaint was taken off the calendar. A hearing regarding approval of the Reliant settlement was held on Friday January 6, 2006 before Judge Lewis.

Reliant has filed a request for dismissal of IE and IPC with prejudice, which was entered by the clerk of the court on December 19, 2005. Pursuant to IE and IPC's stipulation with Reliant, the dismissal will become final once any judgment and order from the Court approving the Reliant settlement with the plaintiffs becomes final (i.e., once the time for any appeal on the order approving the settlements runs or, if review is sought, the trial court's approval order is affirmed after resolution of all appeals). The time for an appeal from an order approving the settlements would range from 30 to 90 days after entry of the Court's judgments and orders.

If the Court does not grant final approval for the Reliant settlement, Reliant may elect to reactivate its cross-complaint. Similarly, should the Court for any reason fail to approve the Reliant settlement by May 31, 2006, IE and IPC may withdraw from the stipulation agreement by giving ten days' advance written notice. IPC intends to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Western Energy Proceedings at the FERC:

California Power Exchange Chargeback:

As a component of IPC's non-utility energy trading in the State of California, IPC, in January 1999, entered into a participation agreement with the California Power Exchange (CalPX), a California non-profit public benefit corporation. The CalPX, at that time, operated a wholesale electricity market in California by acting as a clearinghouse through which electricity was bought and sold. Pursuant to the participation agreement, IPC could sell power to the CalPX under the terms and conditions of the CalPX Tariff. Under the participation agreement, if a participant in the CalPX defaulted on a payment, the other participants were required to pay their allocated share of the default amount to the CalPX. The allocated shares were based upon the level of trading activity, which included both power sales and purchases, of each participant during the preceding three-month period.

On January 18, 2001, the CalPX sent IPC an invoice for $2 million - a "default share invoice" - as a result of an alleged Southern California Edison payment default of $215 million for power purchases. IPC made this payment. On January 24, 2001, IPC terminated its participation agreement with the CalPX. On February 8, 2001, the CalPX sent a further invoice for $5 million, due on February 20, 2001, as a result of alleged payment defaults by Southern California Edison, Pacific Gas and Electric Company and others. However, because the CalPX owed IPC $11 million for power sold to the CalPX in November and December 2000, IPC did not pay the February 8 invoice. The CalPX later reversed IPC's payment of the January 18, 2001 invoice, but on June 20, 2001 invoiced IPC for an additional $2 million which the CalPX has not reversed. The CalPX owes IPC $14 million for power sold in November and December including $2 million associated with the default share invoice dated June 20, 2001. IPC essentially discontinued energy trading with the CalPX and the California Independent System Operator (Cal ISO) in December 2000.

IPC believes that the default invoices were not proper and that IPC owes no further amounts to the CalPX. IPC has pursued all available remedies in its efforts to collect amounts owed to it by the CalPX. On February 20, 2001, IPC filed a petition with the FERC to intervene in a proceeding that requested the FERC to suspend the use of the CalPX chargeback methodology and provide for further oversight in the CalPX's implementation of its default mitigation procedures.

A preliminary injunction was granted by a federal judge in the U.S. District Court for the Central District of California enjoining the CalPX from declaring any CalPX participant in default under the terms of the CalPX Tariff. On March 9, 2001, the CalPX filed for Chapter 11 protection with the U.S. Bankruptcy Court, Central District of California.

In April 2001, Pacific Gas and Electric Company filed for bankruptcy. The CalPX and the Cal ISO were among the creditors of Pacific Gas and Electric Company. To the extent that Pacific Gas and Electric Company's bankruptcy filing affects the collectibility of the receivables from the CalPX and the Cal ISO, the receivables from these entities are at greater risk.

The FERC issued an order on April 6, 2001 requiring the CalPX to rescind all chargeback actions related to Pacific Gas and Electric Company's and Southern California Edison's liabilities. Shortly after the issuance of that order, the CalPX segregated the CalPX chargeback amounts it had collected in a separate account. The CalPX claimed it was awaiting further orders from the FERC and the bankruptcy court before distributing the funds that it collected under its chargeback tariff mechanism. On October 7, 2004, the FERC issued an order determining that it would not require the disbursement of chargeback funds until the completion of the California refund proceedings. On November 8, 2004, IE, along with a number of other parties, sought rehearing of that order. On March 15, 2005, the FERC issued an order on rehearing confirming that the CalPX is to continue to hold the chargeback funds, but solely to offset seller-specific shortfalls in the seller's CalPX account at the conclusion of the California refund proceeding. Balances are to be returned to the respective sellers at the conclusion of a seller's participation in the refund proceeding. Powerex Corp. filed a petition for review of the Commission's order on March 24, 2005 in the D.C. Circuit. Neither a briefing schedule nor a date for oral argument has been set.

Based upon the settlement agreement filed with the FERC on February 17, 2006 between the California Parties and IE and IPC discussed below in "California Refund," the California Parties have agreed to support a request that the FERC authorize the CalPX to release $2.27 million related to the chargeback proceeding to IE and IPC.

California Refund:
In April 2001, the FERC issued an order stating that it was establishing price mitigation for sales in the California wholesale electricity market. Subsequently, in a June 19, 2001 order, the FERC expanded that price mitigation plan to the entire western United States electrically interconnected system. That plan included the potential for orders directing electricity sellers into California since October 2, 2000 to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable, and therefore not in compliance with the Federal Power Act. The June 19 order also required all buyers and sellers in the Cal ISO market during the subject time frame to participate in settlement discussions to explore the potential for resolution of these issues without further FERC action. The settlement discussions failed to bring resolution of the refund issue and as a result, the FERC's Chief Administrative Law Judge submitted a Report and Recommendation to the FERC recommending that the FERC adopt the methodology set forth in the report and set for evidentiary hearing an analysis of the Cal ISO's and the CalPX's spot markets to determine what refunds may be due upon application of that methodology.

On July 25, 2001, the FERC issued an order establishing evidentiary hearing procedures related to the scope and methodology for calculating refunds related to transactions in the spot markets operated by the Cal ISO and the CalPX during the period October 2, 2000 through June 20, 2001 (Refund Period).

The Administrative Law Judge issued a Certification of Proposed Findings on California Refund Liability on December 12, 2002.

The FERC issued its Order on Proposed Findings on Refund Liability on March 26, 2003. In large part, the FERC affirmed the recommendations of its Administrative Law Judge. However, the FERC changed a component of the formula the Administrative Law Judge was to apply when it adopted findings of its staff that published California spot market prices for gas did not reliably reflect the prices a gas market, that had not been manipulated, would have produced, despite the fact that many gas buyers paid those amounts. The findings of the Administrative Law Judge, as adjusted by the FERC's March 26, 2003 order, are expected to increase the offsets to amounts still owed by the Cal ISO and the CalPX to the companies. Calculations remain uncertain because (1) the FERC has required the Cal ISO to correct a number of defects in its calculations, (2) it is unclear what, if any, effect the ruling of the Ninth Circuit in Bonneville Power Administration v. FERC, described below, might have on the ISO's calculations, and (3) the FERC has stated that if refunds will prevent a seller from recovering its California portfolio costs during the Refund Period, it will provide an opportunity for a cost showing by such a respondent. On August 8, 2005, the FERC issued an Order establishing the framework for filings by sellers who elected to make such a cost showing. On September 14, 2005 IE and IPC made a joint cost filing, as did approximately thirty other sellers. On October 11, 2005, the California entities filed comments on the companies' cost filing and those made by other parties. IPC and IE submitted reply comments on October 19, 2005. The California entities filed supplemental comments on October 24, 2005 and IPC and IE filed supplemental reply comments on October 27, 2005. IPC and IE are unsure of the impact the FERC's rulings will have on the refunds due from California. However, as to potential refunds, if any, IPC and IE believe their exposure is likely to be offset by amounts due from California entities.

In December of 2005, IE and IPC reached a tentative agreement with the California Parties settling matters encompassed by the California Refund proceeding including IE and IPC's cost filing and refund obligation. On January 20, 2006, the Parties filed a request with the FERC asking that the FERC defer ruling on IE and IPC's cost filing for thirty days so the parties could complete and file the settlement agreement with the FERC. On January 26, 2006, the FERC granted the requested deferral and required that the settlement be filed by February 17, 2006. On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC. Final comments on the settlement are due to be filed by March 20, 2006, after which the FERC will determine whether to approve the settlement. If the settlement is approved by the FERC, IE and IPC will assign $24.25 million of the rights to accounts receivable from the Cal ISO and CalPX to the California Parties to pay into an escrow account for refunds to settling parties. Amounts from that escrow not used for settling parties and $1.5 million of the remaining IE and IPC receivables which are to be retained by the CalPX are available to fund, at least partially, payment of the claims of any non-settling parties if they prevail in the remaining litigation of this matter. Approximately $10.25 million of the remaining IE and IPC receivables are to be released to IE and IPC. In the fourth quarter of 2005 IE reduced by $9.5 million to $32 million its reserve against these receivables.

IE, along with a number of other parties, filed an application with the FERC on April 25, 2003 seeking rehearing of the March 26, 2003 order. On October 16, 2003, the FERC issued two orders denying rehearing of most contentions that had been advanced and directing the Cal ISO to prepare its compliance filing calculating revised Mitigated Market Clearing Prices and refund amounts within five months. The Cal ISO has since, on a number of occasions, requested additional time to complete its compliance filings. This Cal ISO compliance filing has been delayed until at least March 2006. The Cal ISO is required to update the FERC on its progress monthly.

On December 2, 2003, IE petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC's orders, and since that time, dozens of other petitions for review have been filed. The Ninth Circuit consolidated IE's and the other parties' petitions with the petitions for review arising from earlier FERC orders in this proceeding, bringing the total number of consolidated petitions to more than 100. The Ninth Circuit held the appeals in abeyance pending the disposition of the market manipulation claims discussed below and the development of a comprehensive plan to brief this complicated case. Certain parties also sought further rehearing and clarification before the FERC. On September 21, 2004, the Ninth Circuit convened case management proceedings, a procedure reserved to help organize complex cases. On October 22, 2004, the Ninth Circuit severed a subset of the stayed appeals in order that briefing could commence regarding cases related to: (1) which parties are subject to the FERC's refund jurisdiction under section 201(f) of the Federal Power Act; (2) the temporal scope of refunds under section 206 of the Federal Power Act; and (3) which categories of transactions are subject to refunds. Oral argument was held on April 12-13, 2005. On September 6, 2005 the Ninth Circuit issued its decision in one of the severed cases, Bonneville Power Administration v. FERC. In that decision, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electric energy sales made by governmental entities and non-public utilities. The time for requests for rehearing was to expire on October 21, 2005, but has been extended until 45 days after the Ninth Circuit issues its decision in the other severed cases. IPC cannot predict whether rehearing will be sought and, if sought, whether it will be granted or what action the FERC might take if the matter is remanded.

On May 12, 2004, the FERC issued an order clarifying portions of its earlier refund orders and, among other things, denying a proposal made by Duke Energy North America and Duke Energy Trading and Marketing (and supported by IE) to lodge as evidence a contested settlement in a separate complaint proceeding, California Public Utilities Commission (CPUC) v. El Paso, et al. The CPUC's complaint alleged that the El Paso companies manipulated California energy markets by withholding pipeline transportation capacity into California in order to drive up natural gas prices immediately before and during the California energy crisis in 2000-2001. The settlement will result in the payment by El Paso of approximately $1.69 billion. Duke claimed that the relief afforded by the settlement was duplicative of the remedies imposed by the FERC in its March 26, 2003 order changing the gas cost component of its refund calculation methodology. IE, along with other parties, has sought rehearing of the May 12, 2004 order. On November 23, 2004, the FERC denied rehearing and within the statutory time allowed for petitions, a number of parties, including IE, filed petitions for review of the FERC's order with the Ninth Circuit. These petitions have since been consolidated with the larger number of review petitions in connection with the California refund proceeding.

In June 2001, IPC transferred its non-utility wholesale electricity marketing operations to IE. Effective with this transfer, the outstanding receivables and payables with the CalPX and the Cal ISO were assigned from IPC to IE.

On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, including IE and IPC, alleging that the FERC's market-based rate requirements violate the Federal Power Act, and, even if the market-based rate requirements are valid, that the quarterly transaction reports filed by sellers do not contain the transaction-specific information mandated by the Federal Power Act and the FERC. The complaint stated that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including IE and IPC, to refile their quarterly reports to include transaction-specific data. The Attorney General appealed the FERC's decision to the U.S. Court of Appeals for the Ninth Circuit. The Attorney General contends that the failure of all market-based rate authority sellers of power to have rates on file with the FERC in advance of sales is impermissible. The Ninth Circuit issued its decision on September 9, 2004, concluding that market-based tariffs are permissible under the Federal Power Act, but remanded the matter to the FERC to consider whether the FERC should exercise remedial power (including some form of refunds) when a market participant failed to submit reports that the FERC relies on to confirm the justness and reasonableness of rates charged. Certain parties to the litigation have sought rehearing. IPC cannot predict whether rehearing will be granted or what action the FERC might take if the matter is remanded.

On May 26, 2005 the California Parties filed a motion to lodge additional evidence, primarily audiotapes produced by Enron employees, in the California Refund Proceedings in Docket No. EL00-95. A number of parties, including IDACORP, answered in opposition to that motion.

Market Manipulation:
In a November 20, 2002 order, the FERC permitted discovery and the submission of evidence respecting market manipulation by various sellers during the western power crises of 2000 and 2001.

On March 3, 2003, the California Parties (certain investor owned utilities, the California Attorney General, the California Electricity Oversight Board and the CPUC) filed voluminous documentation asserting that a number of wholesale power suppliers, including IE and IPC, had engaged in a variety of forms of conduct that the California Parties contended were impermissible. Although the contentions of the California Parties were contained in more than 11 compact discs of data and testimony, approximately 12,000 pages, IE and IPC were mentioned only in limited contexts with the overwhelming majority of the claims of the California Parties relating to the conduct of other parties.

The California Parties urged the FERC to apply the precepts of its earlier decision, to replace actual prices charged in every hour starting May 1, 2000 through the beginning of the existing Refund Period with a Mitigated Market Clearing Price, seeking approximately $8 billion in refunds to the Cal ISO and the CalPX. On March 20, 2003, numerous parties, including IE and IPC, submitted briefs and responsive testimony.

In its March 26, 2003 order, discussed above in "California Refund," the FERC declined to generically apply its refund determinations to sales by all market participants, although it stated that it reserved the right to provide remedies for the market against parties shown to have engaged in proscribed conduct.

On June 25, 2003, the FERC ordered over 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior in violation of the Cal ISO and the CalPX Tariffs. The Cal ISO was ordered to provide data on each entity's trading practices within 21 days of the order, and each entity was to respond explaining their trading practices within 45 days of receipt of the Cal ISO data. IPC submitted its responses to the show cause orders on September 2 and 4, 2003. On October 16, 2003, IPC reached agreement with the FERC Staff on the two orders commonly referred to as the "gaming" and "partnership" show cause orders. Regarding the gaming order, the FERC Staff determined it had no basis to proceed with allegations of false imports and paper trading and IPC agreed to pay $83,373 to settle allegations of circular scheduling. IPC believed that it had defenses to the circular scheduling allegation but determined that the cost of settlement was less than the cost of litigation. In the settlement, IPC did not admit any wrongdoing or violation of any law. With respect to the "partnership" order, the FERC Staff submitted a motion to the FERC to dismiss the proceeding because materials submitted by IPC demonstrated that IPC did not use its "parking" and "lending" arrangement with Public Service Company of New Mexico to engage in "gaming" or anomalous market behavior ("partnership"). The "gaming" settlement was approved by the FERC on March 3, 2004. Eight parties have requested rehearing of the FERC's March 3, 2004 order, but the FERC has not yet acted on those requests. The motion to dismiss the "partnership" proceeding was approved by the FERC in an order issued on January 23, 2004 and rehearing of that order was not sought within the time allowed by statute. Some of the California Parties and other parties have petitioned the U.S. Court of Appeals for the Ninth Circuit and the District of Columbia Circuit for review of the FERC's orders initiating the show cause proceedings. Some of the parties contend that the scope of the proceedings initiated by the FERC was too narrow. Other parties contend that the orders initiating the show cause proceedings were impermissible. Under the rules for multidistrict litigation, a lottery was held and although these cases were to be considered in the District of Columbia Circuit by order of February 10, 2005, the District of Columbia Circuit transferred the proceedings to the Ninth Circuit. The FERC had moved the District of Columbia Circuit to dismiss these petitions on the grounds of prematurity and lack of ripeness and finality. The transfer order was issued before a ruling from the District of Columbia Circuit and the motions, if renewed, will be considered by the Ninth Circuit. IPC is not able to predict the outcome of the judicial determination of these issues.

On June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale power markets. In this investigation, the FERC was to review evidence of alleged economic withholding of generation. The FERC determined that all bids into the CalPX and the Cal ISO markets for more than $250 per MWh for the time period May 1, 2000 through October 1, 2000 would be considered prima facie evidence of economic withholding. The FERC Staff issued data requests in this investigation to over 60 market participants including IPC. IPC responded to the FERC's data requests. In a letter dated May 12, 2004, the FERC's Office of Market Oversight and Investigations advised that it was terminating the investigation as to IPC. In March 2005, the California Attorney General, the CPUC, the California Electricity Oversight Board and Pacific Gas and Electric Company sought judicial review in the Ninth Circuit of the FERC's termination of this investigation as to IPC and approximately 30 other market participants. IPC has moved to intervene in these proceedings. On April 25, 2005, Pacific Gas and Electric Company sought review in the Ninth Circuit of another FERC order in the same docketed proceeding confirming the agency's earlier decision not to allow the participation of the California Parties in what the FERC characterized as its non-public investigative proceeding.

The February 17, 2006 Offer of Settlement, if approved by the FERC, would terminate the investigations the FERC initiated without finding of wrongdoing by IE or IPC, and would provide for the disposition of the "gaming" settlement.

Pacific Northwest Refund:
On July 25, 2001, the FERC issued an order establishing another proceeding to explore whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001. The FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001. The Administrative Law Judge found that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that no refunds should be allowed. Procedurally, the Administrative Law Judge's decision is a recommendation to the commissioners of the FERC. Multiple parties submitted comments to the FERC with respect to the Administrative Law Judge's recommendations. The Administrative Law Judge's recommended findings had been pending before the FERC, when at the request of the City of Tacoma and the Port of Seattle on December 19, 2002, the FERC reopened the proceedings to allow the submission of additional evidence related to alleged manipulation of the power market by Enron and others. As was the case in the California refund proceeding, at the conclusion of the discovery period, parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. Grays Harbor, whose civil litigation claims were dismissed, as noted above, intervened in this FERC proceeding, asserting on March 3, 2003 that its six-month forward contract, for which performance had been completed, should be treated as a spot market contract for purposes of the FERC's consideration of refunds and is requesting refunds from IPC of $5 million. Grays Harbor did not suggest that there was any misconduct by IPC or IE. The companies submitted responsive testimony defending vigorously against Grays Harbor's refund claims.

In addition, the Port of Seattle, the City of Tacoma and the City of Seattle made filings with the FERC on March 3, 2003 claiming that because some market participants drove prices up throughout the west through acts of manipulation, prices for contracts throughout the Pacific Northwest market should be re-set starting in May 2000 using the same factors the FERC would use for California markets. Although the majority of these claims are generic, they named a number of power market suppliers, including IPC and IE, as having used parking services provided by other parties under FERC-approved tariffs and thus as being candidates for claims of improperly having received congestion revenues from the Cal ISO. On June 25, 2003, after having considered oral argument held earlier in the month, the FERC issued its Order Granting Rehearing, Denying Request to Withdraw Complaint and Terminating Proceeding, in which it terminated the proceeding and denied claims that refunds should be paid. The FERC denied rehearing on November 10, 2003, triggering the right to file for review. The Port of Seattle, the City of Tacoma, the City of Seattle, the California Attorney General, the CPUC and Puget Sound Energy, Inc. filed petitions for review in the Ninth Circuit. These petitions have been consolidated. Grays Harbor did not file a petition for review, although it has sought to intervene in the proceedings initiated by the petitions of others. On July 21, 2004, the City of Seattle submitted to the Ninth Circuit in the Pacific Northwest refund petition for review a motion requesting leave to offer additional evidence before the FERC in order to try to secure another opportunity for reconsideration by the FERC of its earlier rulings. The evidence that the City of Seattle seeks to introduce before the FERC consisted of audio tapes of what purports to be Enron trader conversations containing inflammatory language that have been the subject of coverage in the press. Under Section 313(b) of the Federal Power Act, a court is empowered to direct the introduction of additional evidence if it is material and could not have been introduced during the underlying proceeding. On September 29, 2004, the Ninth Circuit denied the City of Seattle's motion for leave to adduce evidence, without prejudice to renewing the request for remand in the briefing in the Pacific Northwest refund case. Briefing was completed on May 25, 2005; however, no date has been set for oral argument.

IPC is unable to predict the outcome of these matters.

ATTACHMENT I(d)

IDAHO POWER COMPANY
STATEMENT OF RETAINED EARNINGS
AND
UNDISTRIBUTED SUBSIDIARY EARNINGS
For the Twelve Months Ended December 31, 2005

Retained Earnings

Retained earnings (at the beginning of period)		340,106,848
Balance transferred from income		71,838,830
Dividends received from subsidiary		-
Total		411,945,678
Dividends:		
Common Stock		50,689,545
Total		50,689,545
Retained earnings (at end of period)	$	361,256,133

Undistributed Subsidiary Earnings

Balance (at beginning of period)		30,928,808
Equity in earnings for the period		8,874,042
Dividends paid (Debit)		-
Balance (at end of period)	$	39,802,850

ATTACHMENT I(e)

IDAHO POWER COMPANY
STATEMENT OF INCOME
For the Twelve Months Ended December 31, 2005

	Actual
Operating Revenues	837,682,958
Operating Expenses:	
Purchased power	222,310,315
Fuel	103,163,511
Power cost adjustment	(2,995,109)
Other operation and maintenance expense	241,137,192
Depreciation expense	92,933,330
Amortization of limited-term electric plant	8,551,414
Taxes other than income taxes	20,856,185
Income taxes - Federal	64,853,588
Income taxes - Other	8,931,316
Provision for deferred income taxes	24,279,913
Provision for deferred income taxes - Credit	(58,648,054)
Investment tax credit adjustment	1,950,116
Total operating expenses	727,323,717
Operating Income	110,359,241
Other Income and Deductions:	
Allowance for equity funds used during construction	4,950,151
Income taxes	(683,644)
Other - Net	11,674,343
Net other income and deductions	15,940,850
Income Before Interest Charges	126,300,091
Interest Charges:	
Interest on first mortgage bonds	46,647,381
Interest on other long-term debt	6,692,150
Interest on short-term debt	519,538
Amortization of debt premium, discount and expense - Net	2,423,430
Other interest expense	969,633
Total interest charges	57,252,132
Allowance for borrowed funds used during construction - Credit	2,790,871
Net interest charges	54,461,261
Net Income	$ 71,838,830

The accompanying Notes to Financial Statements are an integral part of this statement

ATTACHMENT III

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION) OF IDAHO POWER COMPANY TO ENTER) INTO CERTAIN FINANCING TRANSACTIONS) FOR THE REFUNDING OF $116,300,000 OF) SWEETWATER COUNTY, WYOMING) POLLUTION CONTROL REVENUE) REFUNDING BONDS) ____________________________________)	CASE NO. IPC-E-06- ____ PROPOSED ORDER

This matter is before the Commission upon the Application of Idaho Power Company ("IPC") filed April ___, 2006, for authority to enter into certain financing transactions for the refunding of outstanding pollution control revenue refunding bonds issued by Sweetwater County, Wyoming ("Sweetwater County"). The Commission, having fully considered the Application and attached exhibits, its files and records relating to the Application and the applicable laws and rules, now makes the following:

FINDINGS OF FACT

I.

The Commission has jurisdiction pursuant to Title 61, Idaho Code, Chapters 1 and 9.

II.

IPC is incorporated under the laws of the State of Idaho and is duly qualified to do business in the states of Oregon, Wyoming, Montana and Nevada in connection with its utility business, with its principal office in Boise, Idaho.

III.

IPC proposes to enter into an agreement with Sweetwater County whereby Sweetwater County will issue and sell not to exceed $116,300,000 aggregate principal amount of one or more series of pollution control revenue refunding bonds (the “Refunding Bonds”) and loan the proceeds from such sale to IPC. IPC will use the loan proceeds, together with certain monies provided by IPC, to refund $116,300,000 aggregate principal amount of Sweetwater County, Wyoming Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 1996A, 1996B and 1996C (the “Outstanding Bonds”), which consist of $68,100,000 principal amount of Series 1996A Bonds ("Series 1996A Bonds"), $24,200,000 principal amount of Series 1996B Bonds ("Series 1996B Bonds") and $24,000,000 principal amount of Series 1996C Bonds ("Series 1996C Bonds").

To the extent that the proceeds from the sale of the Refunding Bonds are not immediately applied to the refunding of the Outstanding Bonds, they may be temporarily invested by the trustee in high grade, short-term taxable securities and short-term government obligations.

IV.

IPC proposes to enter into the refunding transaction to secure a lower average interest rate for the Refunding Bonds, as compared with the Outstanding Bonds. The interest rate or rates may be fixed or variable for the Refunding Bonds, and may be converted to fixed or variable rate(s) during the term(s) of the Refunding Bonds. IPC will notify the Commission by letter within seven (7) days (or as soon as possible, if the required information is not available within seven (7) days) before the issuance of the Refunding Bonds of the likely range of interest rates and other terms for the Refunding Bonds.

V.

IPC expects that the Refunding Bonds will be issued on or prior to July 15, 2006, which is the first redemption date of the Series 1996A Bonds. The Series 1996B Bonds and 1996C Bonds may be redeemed at any time. IPC states that the Refunding Bonds may be issued prior to July 15, 2006 to take advantage of favorable interest rates.

VI.

The Refunding Bonds will mature on July 15, 2026.

VII.

IPC states that the Refunding Bonds will be issued pursuant to an indenture of trust between Sweetwater County and a trustee. Pursuant to a loan agreement between Sweetwater County and IPC, the proceeds from the sale of the Refunding Bonds will be loaned to IPC to pay for the refunding of $116,300,000 aggregate principal amount of the Outstanding Bonds. Under the loan agreement, IPC will be obligated to pay absolutely and unconditionally, to the extent sufficient funds are not already in the possession of the trustee, the principal of, interest on, and premium, if any, on the Refunding Bonds, as well as certain fees and expenses associated with the transaction. Sweetwater County's full faith and credit will not be pledged to the payment of the Refunding Bonds.

VIII.

To achieve favorable ratings by national bond rating agencies for the Refunding Bonds, IPC may collateralize the Refunding Bonds with its own First Mortgage Bonds or other substitute collateral, or it may enter into guarantees, pledges or other security agreements or arrangements to insure timely payment of amounts due in respect of the Refunding Bonds. IPC may also enter into letters of credit, insurance or other arrangements with unrelated parties pursuant to which such parties may lend additional credit or liquidity support to the Refunding Bonds. The intended purpose of such additional credit or liquidity support is to enhance the credit rating of the Refunding Bonds and thereby reduce the interest expense of the Refunding Bonds.

IX.

The Refunding Bonds will be sold on a negotiated public offering basis by Sweetwater County to the underwriters selected for the transaction (the "Underwriters"), pursuant to a contract of purchase. The Underwriters will receive a fee of 0.45% of the aggregate principal amount of the Refunding Bonds offered.

X.

IPC states that, under federal tax laws, it will not be able to increase the principal amount of the Refunding Bonds to include the redemption premium of the Series 1996A Bonds or the underwriter's fees or costs of issuance of the Refunding Bonds. Accordingly, IPC intends to record these amounts as unamortized debt expense and amortize them over the life of the Refunding Bonds.

CONCLUSIONS OF LAW

I.

IPC is incorporated under the State of Idaho and is duly authorized to do business in the states of Oregon, Wyoming, Montana and Nevada in connection with its utility business. IPC is an electrical corporation within the definition of Idaho Code, Section 61-119 and is a public utility within the definition of Idaho Code, Section 61-129.

IT IS FURTHER ORDERED that the issuance of this Order does not constitute acceptance of IPC's exhibits or other material accompanying this Application for any purpose other than the issuance of this Order.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See Idaho Code Section 61-626.

DONE BY ORDER of the Idaho Public Utilities Commission at Boise, Idaho this _____ day of ___________, 2006.

____
PAUL KJELLANDER, President

____
DENNIS S. HANSEN, Commissioner

____
MARSHA H. SMITH, Commissioner

ATTEST:

____
JEAN D. JEWELL
Commission Secretary