IDAHO POWER CO
Form 10-K
March 01, 2007

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2006
OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from .... to ....

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices, zip code and telephone number	IRS Employer Identification Number
1-14465	**IDACORP, Inc.**	82-0505802
1-3198	**Idaho Power Company**	82-0130980
	1221 W. Idaho Street	
	Boise, ID 83702-5627	
	(208) 388-2200	

State of incorporation: Idaho
Websites: www.idacorpinc.com and www.idahopower.com

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:		Name of exchange on which registered
IDACORP, Inc.:	Common Stock, without par value	New York
	Preferred Share Purchase Rights	

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
Idaho Power Company: Preferred Stock

Indicate by check mark whether the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

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

Yes (X) No ( )

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

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, or non-accelerated filers.

IDACORP, Inc.:

Large accelerated filer (X) Accelerated filer ( ) Non-accelerated filer ( )

Idaho Power Company:

Large accelerated filer ( ) Accelerated filer ( ) Non-accelerated filer (X)

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Act).

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

Aggregate market value of voting and non-voting common stock held by nonaffiliates (June 30, 2006):

IDACORP, Inc.: $1,468,190,938 Idaho Power Company: None

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Number of shares of common stock outstanding at January 31, 2007:

IDACORP, Inc.:	43,635,183
Idaho Power Company:	39,150,812 all held by IDACORP, Inc.

Documents Incorporated by Reference:

Part III, Items 10 - 14	Portions of IDACORP, Inc.'s definitive proxy statement to be filed pursuant to Regulation
-	14A for the 2007 Annual Meeting of Shareholders to be held on May 17, 2007.

This combined Form 10-K represents separate filings by IDACORP, Inc. and Idaho Power Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Idaho Power Company makes no representation as to the information relating to IDACORP, Inc.'s other operations.

Idaho Power Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

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COMMONLY USED TERMS

AFDC	-	Allowance for Funds Used During Construction
ARO	-	Asset Retirement Obligation
Cal ISO	-	California Independent System Operator
CalPX	-	California Power Exchange
cfs	-	Cubic feet per second
CSPP	-	Cogeneration and Small Power Production
Energy Act	-	Energy Policy Act of 2005
EPS	-	Earnings per share
ESA	-	Endangered Species Act
FASB	-	Financial Accounting Standards Board
FERC	-	Federal Energy Regulatory Commission
FIN	-	Financial Accounting Standards Board Interpretation
Fitch	-	Fitch, Inc.
FPA	-	Federal Power Act
FSP	-	Financial Accounting Standards Board Staff Position
GAAP	-	Generally Accepted Accounting Principles
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
IE	-	IDACORP Energy, a subsidiary of IDACORP, Inc.
IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPC	-	Idaho Power Company, a subsidiary of IDACORP, Inc.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
ITI	-	IDACORP Technologies, Inc.
kW	-	Kilowatt
maf	-	Million acre feet
MD&A	-	Management's Discussion and Analysis of Financial Condition and Results of Operations
Moody's	-	Moody's Investors Service
MW	-	Megawatt
MWh	-	Megawatt-hour
NEPA	-	National Environmental Policy Act of 1996
O&M	-	Operations and Maintenance
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PM&E	-	Protection, Mitigation and Enhancement
PURPA	-	Public Utility Regulatory Policies Act of 1978
RFP	-	Request for Proposal
RTO	-	Regional Transmission Organization
S&P	-	Standard & Poor's Ratings Services
SFAS	-	Statement of Financial Accounting Standards
SO_2	-	Sulfur Dioxide
Valmy	-	North Valmy Steam Electric Generating Plant
VIEs	-	Variable Interest Entities

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*Except as indicated in Item 12, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2007 Annual Meeting of Shareholders.

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SAFE HARBOR STATEMENT

This Form 10-K contains "forward-looking statements" intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-K at Part II, Item 7- "Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) - FORWARD-LOOKING INFORMATION." Forward-looking statements are all statements other than statements of historical fact, including without limitation those that are identified by the use of the words "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "may result," "may continue," or similar expressions.

PART I - IDACORP, Inc. and Idaho Power Company

ITEM 1. BUSINESS

OVERVIEW:

IDACORP, Inc. (IDACORP) is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power Company (IPC). IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005 (2005 Act), which provides certain access to books and records to the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions and imposes certain record retention and reporting requirements on IDACORP.

IPC is an electric utility engaged in the generation, transmission, distribution, sale and purchase of electric energy and is regulated by the FERC and the state regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co., a joint venturer in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

IDACORP's other subsidiaries include:

IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments;

Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and

IDACORP Energy (IE), a marketer of energy commodities, which wound down operations in 2003.

IDACORP is focusing on a strategy that emphasizes IPC as IDACORP's core business. IPC continues to experience strong customer growth in its service area, and this corporate strategy recognizes that IPC must make substantial investments in infrastructure to ensure adequate electricity supply and reliable service. IFS and Ida-West remain components of the corporate strategy.

In the second quarter of 2006, IDACORP management designated the operations of IDACORP Technologies, Inc. (ITI) and IDACOMM as assets held for sale, as defined by Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"*. IDACORP's consolidated financial statements reflect the reclassification of the results of these businesses as discontinued operations for all periods presented. Discontinued operations are discussed in more detail in Note 17 to IDACORP's and IPC's Consolidated Financial Statements.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited.

On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc.

At December 31, 2006, IDACORP had 1,976 full-time employees, 1,927 of which were employed by IPC.

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IDACORP's reportable business segments are IPC and IFS, which contributed $94 million and $10 million, respectively, to income from continuing operations in 2006. Financial information relating to IDACORP's reportable segments is presented in Note 11 to IDACORP's and IPC's Consolidated Financial Statements and below in "Utility Operations," and "IFS."
IDACORP and IPC make available free of charge their Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the Securities and Exchange Commission, through IDACORP's website at www.idacorpinc.com and through a link to the IDACORP website from the IPC website at www.idahopower.com.

UTILITY OPERATIONS:

IPC was incorporated under the laws of the state of Idaho in 1989 as successor to a Maine corporation organized in 1915. IPC's service territory covers a 24,000 square mile area in southern Idaho and eastern Oregon, with an estimated population of 943,000. IPC holds franchises in 71 cities in Idaho and nine cities in Oregon and holds certificates from the respective public utility regulatory authorities to serve all or a portion of 24 counties in Idaho and three counties in Oregon. As of December 31, 2006, IPC supplied electric energy to approximately 472,000 general business customers.

IPC owns and operates 17 hydroelectric generation developments, two natural gas-fired plants and one diesel-powered generator and shares ownership in three coal-fired generating plants. These generating plants and their capacities are listed in Item 2 - "Properties." IPC's coal-fired plants are in Wyoming, Oregon and Nevada, and use low-sulfur coal from Wyoming and Utah.

IPC is one of the nation's few investor-owned utilities with a predominantly hydroelectric generating base. Because of its reliance on hydroelectric generation, IPC's generation operations can be significantly affected by weather conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of IPC's hydroelectric facilities, reservoir storage, springtime snow pack run-off, rainfall and other weather and stream flow management considerations. During low water years, when stream flows into IPC's hydroelectric projects are reduced, IPC's hydroelectric generation is reduced. This results in less generation from IPC's resource portfolio (hydroelectric, coal-fired and gas-fired) available for off-system sales and, most likely, an increased use of purchased power to meet load requirements. Both of these situations - a reduction in off-system sales and an increased use of more expensive purchased power - result in increased power supply costs.

The primary influences on electricity sales are weather, customer growth and economic conditions. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Increased precipitation levels during the agricultural growing season reduce electricity sales to customers who use electricity to operate irrigation pumps.

IPC's principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, forest product production, beet sugar refining and the skiing industry.

Regulation

IPC is under the regulatory jurisdiction (as to rates, service, accounting and other general matters of utility operation) of the FERC, the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC). IPC is also under the regulatory jurisdiction of the IPUC, the OPUC and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. IPC is subject to the provisions of the Federal Power Act as a "public utility" as therein defined. IPC's retail rates are established under the jurisdiction of the state regulatory commissions and its wholesale and transmission rates are regulated by the FERC (see "Rates" below). Pursuant to the requirements of Section 210 of PURPA, the state regulatory commissions have each issued orders and rules regulating IPC's purchase of power from cogeneration and small power production (CSPP) facilities.

IPC is subject to the provisions of the Federal Power Act as a "licensee" as therein defined. As a licensee under the Federal Power Act, IPC and its licensed hydroelectric projects are subject to the provisions of Part I of the Federal Power Act. All licenses are subject to conditions set forth in the Federal Power Act and related FERC regulations. These conditions and regulations include provisions relating to condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment, severance damages and other matters.

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The State of Oregon has a Hydroelectric Act providing for licensing of hydroelectric projects in that state. IPC's Brownlee, Oxbow and Hells Canyon facilities are on the Snake River where it forms the boundary between Idaho and Oregon and occupy lands in both states. With respect to project property located in Oregon, these facilities are subject to the Oregon Hydroelectric Act. IPC has obtained Oregon licenses for these facilities and these licenses are not in conflict with the Federal Power Act or IPC's FERC licenses (see Part II, Item 7 - "MD&A - REGULATORY MATTERS - Relicensing of Hydroelectric Projects").

Rates

The rates IPC charges to its general business customers are determined by the IPUC and the OPUC. Approximately 95 percent of IPC's general business revenue comes from customers in Idaho. 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. For further discussion of significant rate cases and proceedings see Part II, Item 7 - "MD&A - REGULATORY MATTERS."

Energy Efficiency

In 2006, IPC spent approximately $10 million to promote energy efficiency and summer peak reduction through its Demand Side Management (DSM) programs. Major funding for program development, implementation and administration comes from the Idaho and Oregon tariff riders for DSM and from the Conservation & Renewables Discount Program of the Bonneville Power Administration.

Approximately nine percent of the total DSM spending related to research and development, technology evaluation and market transformation, through promotion and collaboration with manufacturers of electricity consuming products, including air conditioning equipment, appliances, building components and control equipment. A portion of this activity was accomplished in conjunction with the Northwest Energy Efficiency Alliance.

Energy efficiency programs target savings across the entire year for a wide range of customer segments with an emphasis on reducing energy during the summer peak:

Approximately 22 percent of the 2006 expenses were devoted to achieving summer peak reduction through focusing on irrigation pumping and residential air conditioning equipment control measures.

The residential energy efficiency programs targeted new and existing homes, focusing on customer education and the application of energy efficiency remediation, including energy efficient building techniques, insulation augmentation, air duct sealing, and the use of efficient lighting. The segment's 2006 spending represented about 23 percent of the total.

Energy Efficiency programs for existing industrial and new commercial facilities focus on application of energy efficient techniques and technologies as well as operational and management processes to reduce energy consumption. These programs represented approximately 18 percent of total expenses.

Approximately 24 percent of the 2006 expenses were devoted to irrigation efficiency programs. Irrigation customers can receive financial incentives for either improving the energy efficiency of an irrigation system or installing a new energy efficiency system.

Power Supply

IPC meets its system load requirements using a combination of its own generation, mandated purchases from private developers (see "CSPP Purchases" below) and purchases from other utilities and power wholesalers. IPC's generating plants and capacities are listed in Item 2 - "Properties."

IPC's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand is 3,084 megawatts (MW), set on July 24, 2006. The peak winter demand for the year was 2,318 MW on December 18. IPC expects total system average load to grow 2.1 percent annually over the next three years.

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The following table presents IPC's system generation for the last three years:

	MWh			Percent of total generation		
	2006	2005	2004	2006	2005	2004
	(thousands of MWhs)					
Hydroelectric	9,207	6,199	6,041	57%	46%	45%
Thermal	7,021	7,315	7,303	43%	54%	55%
Total system generation	16,228	13,514	13,344	100%	100%	100%

The amount of electricity IPC is able to generate from its hydroelectric plants depends on a number of factors, primarily snow pack in the mountains upstream of its hydroelectric facilities, reservoir storage and stream flow conditions. When these factors are favorable, IPC can generate more electricity using its hydroelectric plants.

Under normal stream flow conditions, IPC's system generation mix is approximately 55 percent hydroelectric and 45 percent thermal.

Stream flow conditions in 2006 were much improved over 2005. The observed stream flow data released by the National Weather Service's Northwest River Forecast Center indicated that Brownlee reservoir inflow for April through July 2006 was 8.95 million acre-feet (maf), or 142 percent of average. Brownlee reservoir inflow for 2006 totaled 16.98 maf, or 123 percent of average. Storage in selected federal reservoirs upstream of Brownlee as of February 11, 2007 was 122 percent of average. The stream flow forecast released on February 15, 2007 by the National Weather Service's Northwest River Forecast Center predicts that Brownlee reservoir inflow for April through July 2007 will be 3.80 maf; or 60 percent of average.

IPC's generating facilities are interconnected through its integrated transmission system and are operated on a coordinated basis to achieve maximum load-carrying capability and reliability. IPC's transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration, Avista Corporation, PacifiCorp, NorthWestern Energy and Sierra Pacific Power Company. Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase and sale of power among all major electric systems in the west. IPC is a member of the Western Electricity Coordinating Council, the Western Systems Power Pool, the Northwest Power Pool and the North American Energy Standards Board. These groups have been formed to more efficiently coordinate transmission reliability and planning throughout the western grid. See "Competition - Wholesale" below.

Integrated Resource Plan: IPC's IRP is prepared and filed every two years with the IPUC and the OPUC. Prior to filing, the IRP requires extensive involvement by IPC, the IPUC Staff, the OPUC Staff, and customer and environmental representatives, as well as input on the cost of various generation technologies. The IRP is the starting point for demonstrating prudence in IPC's resource decisions. The 2006 IRP identified IPC's forecast load and resource situation for the next twenty years, analyzed potential supply-side and demand-side options and identified near-term and long-term actions. The two primary goals of the 2006 IRP were to (1) identify sufficient resources to reliably serve the growing demand for electric service within IPC's service area throughout the 20-year planning period and (2) ensure that the portfolio of resources selected balances cost, risk and environmental concerns. In addition, there were four secondary goals: (1) to give equal and balanced treatment to both supply-side resources and demand-side measures, (2) to involve the public in the planning process in a meaningful way, (3) to explore transmission alternatives, and (4) to investigate and evaluate advanced coal technologies. The 2006 IRP was submitted to the IPUC in September 2006 and the OPUC in October 2006. See further discussion in Part II - Item 7 - "MD&A - REGULATORY MATTERS - Integrated Resource Plan."

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CSPP Purchases: As mandated by the enactment of PURPA and the adoption of avoided cost rates by the IPUC and the OPUC, IPC has entered into contracts for the purchase of energy from a number of private developers. Under these contracts, IPC is required to purchase all of the output from the facilities located inside the IPC service territory. For projects located outside the IPC service territory, IPC is required to purchase the output that IPC has the ability to receive at the facility's requested point of delivery on the IPC system. The IPUC jurisdictional portion of the costs associated with CSPP contracts are fully recovered through the PCA. For IPUC jurisdictional contracts, projects that generate up to ten average MW of energy monthly are eligible for IPUC Published Avoided Costs for up to a 20-year contract term. The Published Avoided Cost is a price established by the IPUC and OPUC to estimate IPC's cost of developing additional generation resources. On August 4, 2005, the IPUC granted a temporary reduction in the eligible project size to 100 kW for intermittent generation resources only and ordered IPC to study the impacts of integrating this type of resource. IPC completed and filed with the IPUC a wind generation integration study report on February 6, 2007. The IPUC will evaluate the proposal, possibly including public workshops, and issue a ruling. For OPUC jurisdictional contracts, projects with a nameplate rating of up to ten MW of capacity are eligible for OPUC Published Avoided Costs for up to a 20-year contract term. The OPUC jurisdictional portion of the costs associated with CSPP contracts is recovered through general rate case filings. The Oregon provisions are currently being reviewed in an OPUC proceeding, as discussed in Part II, Item 7 - "MD&A - REGULATORY MATTERS - Public Utility Regulatory Policies Act of 1978." If a PURPA project does not qualify for Published Avoided Costs, then IPC is required to negotiate the terms, prices and conditions with the developer of that project. These negotiations reflect the characteristics of the individual projects (i.e., operational flexibility, location and size) and the benefits to the IPC system and must be consistent with other similar energy alternatives.

As of December 31, 2006, IPC had signed agreements to purchase energy from 92 CSPP facilities with contracts ranging from one to 30 years. Of these facilities, 74 were on-line at the end of 2006; the other 18 facilities under contract are due to come on-line in 2007 and 2008. During 2006, IPC purchased 911,132 megawatt hours (MWh) from these projects at a cost of $54 million, resulting in a blended price of 5.9 cents per kilowatt hour.

Wholesale Energy Market Activities: Guided by a risk management policy and frequently updated operating plans, IPC participates in the wholesale energy market by buying power to help meet load demands and selling power that is in excess of load demands. IPC's market activities are influenced by its customer loads, market prices, and cost and availability of generating resources. Some of IPC's hydroelectric generation facilities are operated to optimize the water that is available by choosing when to run generation units and when to store water in reservoirs. These decisions affect the timing and volumes of market purchases and market sales. Even in below normal water years, there are opportunities to vary water usage to maximize generation unit efficiency, capture marketplace economic benefits and meet load demand. Compliance factors, such as allowable river stage elevation changes and flood control requirements, and wholesale energy market prices influence these dispatch decisions.

IPC has one firm wholesale power sales contract and one wholesale contract for load following services. The sales contract is with the Raft River Electric Cooperative for up to 15 MW. This contract expires in September 2007; however, Raft River Electric Cooperative has provided notice that it intends to renew the contract, as allowed in the original agreement, through September 2010. The load following contract, with NorthWestern Energy, requires IPC to increase or decrease its generation by up to 30 MW to react to NorthWestern's system load changes. This contract automatically renews annually unless either party chooses to terminate. Due to the uncertainty regarding the regulation requirements of anticipated wind generation, IPC expects to terminate this contract effective December 2007.

IPC has one firm wholesale purchased power contract. This contract is with PPL Montana, LLC for 83 MW per hour to address increased demand during June, July and August. The term of this contract began in June 2004 and runs through August 2009.

Transmission Services: IPC has a long history of providing wholesale transmission service and provides firm and non-firm wheeling services for several surrounding utilities. IPC's system lies between and is interconnected to the winter-peaking northern and summer-peaking southern regions of the western interconnected power system. This geographic position allows IPC to provide transmission services and reach a broad power sales market.

IPC holds rights-of-way from Midpoint substation in south-central Idaho through eastern Nevada to the Dry Lake area northeast of Las Vegas, Nevada, known as the Southwest Intertie Project (SWIP). In 2004, the Bureau of Land Management granted a five-year extension to begin construction of a proposed 500-kilovolt transmission line within the rights-of-way to December 2009. IPC obtained the rights-of-way to construct a transmission line along this corridor, but no longer plans to build the line. On March 31, 2005, IPC entered into an agreement with White Pine Energy Associates, LLC (White Pine), an affiliate of LS Power Development, LLC, which provides White Pine a three-year exclusive option to purchase the SWIP rights-of-way from IPC. The option may be exercised in part or as a whole and, if fully exercised, will result in a net pre-tax gain to IPC of approximately $6 million.

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In December 1999, the FERC issued Order No. 2000 encouraging companies with transmission assets to form Regional Transmission Organizations. See "Competition - Wholesale" below.

Fuel

IPC, through its subsidiary Idaho Energy Resources Co., owns a one-third interest in Bridger Coal Company, which owns the Jim Bridger mine supplying coal to the Jim Bridger generating plant in Wyoming. The mine, located near the Jim Bridger plant, operates under a long-term sales agreement that provides for delivery of coal over a 51-year period ending in 2024. The Jim Bridger mine has sufficient reserves to provide coal deliveries for the term of the sales agreement. IPC also has a coal supply contract providing for annual deliveries of coal through 2009 from the Black Butte Coal Company's Black Butte and Leucite Hills mines located near the Jim Bridger plant. This contract supplements the Bridger Coal Company deliveries and provides another coal supply to operate the Jim Bridger plant. The Jim Bridger plant's rail load-in facility and unit coal train allow the plant to take advantage of potentially lower-cost coal from other mines for tonnage requirements above established contract minimums.

In an effort to lower costs and access better quality coal, the Jim Bridger mine is converting from a surface operation to a primarily underground operation. Underground mine development and limited coal production began in 2004, and start-up operations are expected to begin in March 2007. A number of factors were considered in this decision including the increasing cost of the surface mine operation as well as the additional capital required to develop the underground mine. This conversion is expected to result in a reduction of the cost of mining coal over the life of the Jim Bridger Mine.

Sierra Pacific Power Company, as operator of the North Valmy Generating Plant (Valmy), has an agreement with Arch Coal Sales Company, Inc. to supply coal to the plant through 2009. IPC is obligated to purchase one-half of the coal, ranging from 515,000 tons to 762,500 tons annually. Sierra Pacific Power Company also has a coal supply contract with Black Butte Coal Company's Black Butte Mine for deliveries through 2009. IPC is obligated to purchase one-half of the coal purchased under this agreement, ranging from 450,000 to 600,000 tons annually.

The Boardman generating plant receives coal from the Powder River Basin through annual contracts. Portland General Electric, as operator of the Boardman plant, has an agreement with Buckskin Mining Company to supply all of Boardman's coal requirements through 2008. IPC is obligated to purchase 10 percent of the coal purchased under this agreement, ranging from 230,000 to 270,000 tons annually.

IPC owns and operates the Danskin and Bennett Mountain combustion turbines, which receive gas through the Williams Northwest Pipeline. All gas is purchased as needs are identified for summer peaks or to meet system requirements. The gas is transported under a long-term capacity contract with the Williams Northwest Pipeline and an arrangement with IGI Resources, Inc. The Williams Northwest Pipeline contract, which extends through February 28, 2007, with annual extensions at IPC's sole discretion, is for 24,523 million British thermal units (MMBtu) per day from the Sumas, Washington metering point to the Elmore, Idaho metering point. In addition to a long-term capacity contract, IPC has entered into a long-term contract with Williams Northwest Pipeline for storage capacity at the Jackson Prairie Storage Project located in Lewis County, Washington. As the project is developed, storage capacity will be phased into service and allocated to IPC monthly, until reaching 11,267 MMBtu per day of firm deliverability. Storage capacity is expected to commence in March 2007, reaching maximum deliverability by November 1, 2008.

The firm storage contract extends through November 1, 2043, with bi-lateral termination rights at the end of the contract. Storage gas will be purchased and stored with the intent of supplying needs as identified for summer peaks or to meet system requirements. See further discussion in Part II, Item 7 - "MD&A - RESULTS OF OPERATIONS - Utility Operations - Fuel Expense."

Water Rights

Except as discussed below, IPC has acquired water rights under applicable state law for all waters used in its hydroelectric generating facilities. In addition, IPC holds water rights for domestic, irrigation, commercial and other necessary purposes related to other land and facility holdings within the state. The exercise and use of all of these water rights are subject to prior rights, and with respect to certain hydroelectric generating facilities, IPC's water rights for power generation are subordinated to certain future upstream diversions of water for irrigation and other recognized consumptive uses.

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Over time, increased irrigation development and other consumptive diversions have resulted in a reduction in the stream flows available to fulfill IPC's water rights at certain hydroelectric generating facilities. In reaction to these reductions, IPC initiated and continues to pursue a course of action to determine and protect its water rights. As part of this process, IPC and the State of Idaho signed the Swan Falls agreement on October 25, 1984, which provided a level of protection for IPC's hydropower water rights at specified plants by setting minimum stream flows and establishing an administrative process governing the future development of water rights that may affect IPC's hydroelectric generation. In 1987, Congress passed, and the President signed into law, House Bill 519. This legislation permitted implementation of the Swan Falls agreement and further provided that during the remaining term of certain of IPC's project licenses the relationship established by the agreement would not be considered by the FERC as being inconsistent with the terms of IPC's project licenses or imprudent for the purposes of determining rates under Section 205 of the Federal Power Act. The FERC entered an order implementing the legislation on March 25, 1988.

In addition to providing for the protection of IPC's hydroelectric water rights, the Swan Falls agreement contemplated the initiation of a general adjudication of all water uses within the Snake River basin. In 1987, the director of the Idaho Department of Water Resources filed a petition in state district court asking that the court adjudicate all claims to water rights, whether based on state or federal law, within the Snake River basin. The court signed a commencement order initiating the Snake River Basin Adjudication on November 19, 1987. This legal proceeding was authorized by state statute based upon a determination by the Idaho Legislature that the effective management of the waters of the Snake River basin required a comprehensive determination of the nature, extent and priority of all water uses within the basin. The adjudication is proceeding and is expected to continue for at least the next several years. IPC has filed claims to its water rights within the basin and is actively participating in the adjudication in an effort to ensure that its water rights and the operation of its hydroelectric facilities are not adversely impacted.

Please see Part II, Item 7 - "MD&A - LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Idaho Water Management Issues" and "MD&A - REGULATORY MATTERS - Relicensing of Hydroelectric Projects."

Environmental Regulation

IPC's activities are subject to a broad range of federal, state, regional and local laws and regulations designed to protect, restore and enhance the quality of the environment. Environmental regulation continues to impact IPC's operations due to the cost of installation and operation of equipment and facilities required for compliance with such regulations, and the modification of system operations to accommodate such regulations. IPC's compliance costs will continue to be significant for the foreseeable future.

Based upon present environmental laws and regulations, IPC estimates its 2007 capital expenditures for environmental matters, excluding Allowance for Funds Used During Construction (AFDC), will total $30 million. Studies and measures related to environmental concerns at IPC's hydroelectric facilities account for $19 million, and investments in environmental equipment and facilities at the thermal plants account for $11 million. For 2008 and 2009, environmental-related capital expenditures, excluding AFDC, are estimated to be $44 million. Anticipated expenses related to IPC's hydroelectric facilities account for $31 million, and thermal plant expenses are expected to total $13 million.

IPC anticipates $19 million in annual operating costs for environmental facilities during 2007. Hydroelectric facility expenses account for $12 million of this total, and $7 million is related to thermal plant operating expenses. For 2008 and 2009, total environmental related operating costs are estimated to be $50 million. Expenses related to the hydroelectric facilities are expected to be $35 million, and thermal plant expenses are expected to be $15 million during this period.

Air Quality Issues

IPC owns two natural gas combustion turbine power plants and co-owns three coal-fired power plants that are subject to air quality regulation. The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. The coal-fired plants are: Jim Bridger (33 percent interest) located in Wyoming; Boardman (ten percent interest) located in Oregon; and North Valmy (50 percent interest) located in Nevada. Please see Part II, Item 7 - "MD&A - LEGAL AND ENVIRONMENTAL ISSUES - Environmental Issues - Air Quality Issues" for a discussion of these matters.

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Water: As required under the Federal Water Pollution Control Act Amendments of 1972, IPC has received necessary environmental permits and authorizations and has prepared necessary plans relating to operations and water quality, such as effluent discharge, spill prevention and countermeasures, and storm water pollution prevention.

In March 1976, IPC agreed to operate its American Falls hydroelectric generating plant to meet certain dissolved oxygen standards in the Snake River downstream from the plant during the period from May 15 to October 15 of each year and to provide water quality monitoring facilities. In order to meet the dissolved oxygen standards, IPC installed and operates aeration equipment at the American Falls plant.

IPC has also installed aeration equipment, water quality monitors and data processing equipment as part of its Cascade hydroelectric project to provide accurate water quality data and increase dissolved oxygen levels as necessary to maintain water quality standards on the Payette River. IPC has also installed and operates water quality monitors at its Milner, Shoshone Falls, Twin Falls, Upper Salmon, Lower Salmon, Bliss and CJ Strike hydroelectric projects in order to meet compliance standards for water quality on the Snake River.

Endangered Species: In December 1992, the U.S. Fish and Wildlife Service listed several species of fish and five species of snails living within IPC's operating area as threatened or endangered species under the Endangered Species Act. IPC continues to review and analyze the effect such designation has on its operations and is cooperating with governmental agencies to resolve issues related to these species.

On December 21, 2006, IPC and Idaho Governor James Risch submitted a petition to the U.S. Fish and Wildlife Service to de-list the threatened Bliss Rapids snail. The petition was supported with data collected by IPC over the past 14 years. The snail, which lives throughout the middle Snake River, springs, and tributaries between Niagara Springs and King Hill, was listed as threatened under the Endangered Species Act in 1992. The Fish and Wildlife Service has one year to decide if de-listing is warranted. With this filing, three of the five snail species that are found in the middle Snake River and were originally listed as threatened or endangered species in 1992 are now being considered for removal from the list.

Pursuant to FERC License 1971, IPC owns and finances the operation of anadromous fish hatcheries and related facilities to mitigate the effects of its hydroelectric dams on fish populations. In connection with its fish facilities, IPC sponsors ongoing programs for the control of fish disease, improvement of fish production, and evaluation of hatchery performance. IPC's anadromous fish facilities at Hells Canyon, Oxbow, Rapid River, Pahsimeroi and Niagara Springs continue to be operated by the Idaho Department of Fish and Game. At December 31, 2006, the investment in these facilities was $15 million and the annual cost of operation was $3 million.

Hazardous/Toxic Wastes and Substances: Under the Toxic Substances Control Act, the EPA has adopted regulations governing the use, storage, inspection and disposal of electrical equipment that contains polychlorinated biphenyls (PCBs). The regulations permit the continued use and servicing of certain equipment (including transformers and capacitors) that contain PCBs. IPC continues to meet all federal requirements of the Toxic Substances Control Act for the continued use of equipment containing PCBs. IPC continues to eliminate PCBs as part of its long-term strategy. This program will reduce costs associated with the long-term monitoring of PCB-containing equipment, responding to spills and reporting to the EPA. In 2006, IPC spent approximately $0.9 million identifying and eliminating PCBs.

Competition

Retail: Electric utilities have historically been recognized as natural monopolies and have operated in a highly regulated environment in which they have an obligation to provide electric service to their customers in return for an exclusive franchise within their service territory with an opportunity to earn a regulated rate of return.

Some state regulatory authorities are in the process of changing utility regulations in response to federal and state statutory changes and evolving competitive markets. These statutory changes and conforming regulations may result in increased retail competition. In 1997, the Idaho Legislature appointed a committee to study restructuring of the electric utility industry. The committee has not recommended any restructuring legislation and is not expected to in the foreseeable future. The committee's focus has since shifted from restructuring to general energy issues. In 1999, the Oregon Legislature passed legislation restructuring the electric utility industry, but exempted IPC's service territory.

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Wholesale: The 1992 National Energy Policy Act and the FERC's rulemaking activities have established the regulatory framework to open the wholesale energy market to competition. This act permits utilities to develop independent electric generating plants for sales to wholesale customers, and authorizes the FERC to order transmission access for third parties to transmission facilities owned by another entity. This act does not, however, permit the FERC to require transmission access to retail customers. Open-access transmission for wholesale customers provides energy suppliers with opportunities to sell and deliver electricity at market-based prices.

For more information, see Part II, Item 7 - "MD&A - REGULATORY MATTERS - Regional Transmission Organizations."

Utility Operating Statistics

The following table presents IPC's revenues and energy use by customer type for the last three years, which is further discussed in Part II, Item 7 - "MD&A - RESULTS OF OPERATIONS - Utility Operations:"

	Years Ended December 31,		
	2006	**2005**	**2004**
Revenues (thousands of dollars)			
Residential	$ 299,594	$ 299,488	$ 274,313
Commercial	162,391	173,268	164,053
Industrial	102,958	118,259	111,797
Irrigation	71,432	76,255	85,672
Total general business	636,375	667,270	635,835
Off-system sales	260,717	142,794	121,148
Other	23,381	27,619	62,526
Total	$ 920,473	$ 837,683	$ 819,509
Energy use (thousands of MWh)			
Residential	5,068	4,760	4,580
Commercial	3,761	3,639	3,561
Industrial	3,475	3,423	3,335
Irrigation	1,635	1,467	1,763
Total general business	13,939	13,289	13,239
Off-system sales	5,821	2,774	2,885
Total	19,760	16,063	16,124

See Note 11 to IDACORP's and IPC's Consolidated Financial Statements for more information.

IFS:

IFS invests primarily in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and accelerated tax depreciation benefits. IFS generated tax credits of $19 million, $20 million and $22 million in 2006, 2005 and 2004, respectively. IFS's portfolio also includes historic rehabilitation projects such as the Empire Building in Boise, Idaho. IFS made $5 million in new investments during 2006.

IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk. Over 90 percent of IFS's investments have been made through syndicated funds. At December 31, 2006, the gross amount of IFS's portfolio equaled $175 million in tax credit investments. These investments cover 49 states, Puerto Rico and the U.S. Virgin Islands. The underlying investments include over 700 individual properties, of which all but three are administered through syndicated funds.

See Note 11 to IDACORP's and IPC's Consolidated Financial Statements for more information.

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IDA-WEST:

Ida-West operates and has a 50 percent interest in nine hydroelectric plants with a total generating capacity of 45 MW. Four of the projects are located in Idaho and five are in northern California. All nine projects are "qualifying facilities" under PURPA. IPC purchased all of the power generated by Ida-West's four Idaho hydroelectric projects at a cost of $8 million in 2006, and $7 million per year in 2005 and 2004.

ITEM 1A. RISK FACTORS

The following are factors that could have a significant impact on the operations and financial results of IDACORP, Inc. and Idaho Power Company and could cause actual results or outcomes to differ materially from those discussed in any forward-looking statements:

- **Reduced hydroelectric generation can reduce revenues and increase costs.** Idaho Power Company has a predominately hydroelectric generating base. Because of Idaho Power Company's heavy reliance on hydroelectric generation, the weather can significantly affect its operations. When hydroelectric generation is reduced, Idaho Power Company must increase its use of generally more expensive thermal generating resources and purchased power. Through its power cost adjustment in Idaho, Idaho Power Company can expect to recover approximately 90 percent of the increase in its Idaho jurisdictional net power supply costs, which are fuel and purchased power less off-system sales, above the level included in its base rates. The power cost adjustment recovery includes both a forecast and deferrals that are subject to the regulatory process. However, recovery of amounts above forecast in one power cost adjustment year does not occur until the subsequent power cost adjustment year. The non-Idaho net power supply costs are subject to periodic recovery from the Oregon and Federal Energy Regulatory Commission jurisdictional customers.
- **Continuing declines in stream flows and over-appropriation of water in Idaho may reduce hydroelectric generation and revenues and increase costs.** The combination of declining Snake River base flows, over-appropriation of water and drought conditions have led to disputes among surface water and ground water irrigators, and the State of Idaho. Recharging the Eastern Snake Plain Aquifer, which contributes to Snake River flows, by diverting surface water to porous locations and permitting it to sink into the aquifer is one proposed solution to the dispute. Diversions from the Snake River for aquifer recharge may further reduce Snake River flows available for hydroelectric generation and reduce Idaho Power Company revenues and increase costs.
- **Changes in temperature and precipitation can reduce power sales and revenues.** Warmer than normal winters, cooler than normal summers and increased rainfall during the irrigation seasons will reduce retail revenues from power sales.
- **If the Idaho Public Utilities Commission, the Oregon Public Utility Commission or the Federal Energy Regulatory Commission grant less rate relief than requested in rate case filings, Idaho Power Company's earnings and cash flows will be reduced.** If the Idaho Public Utilities Commission, the Oregon Public Utility Commission or the Federal Energy Regulatory Commission were to grant less rate relief than Idaho Power Company requests in its rate case filings, it would have a negative effect on earnings and cash flow and could result in downgrades of IDACORP, Inc.'s and Idaho Power Company's credit ratings.
- **Conditions that may be imposed in connection with hydroelectric license renewals may require large capital expenditures and reduce earnings and cash flows.** Idaho Power Company is currently involved in

renewing federal licenses for several of its hydroelectric projects. The Federal Energy Regulatory Commission may impose conditions with respect to environmental, operating and other matters in connection with the renewal of Idaho Power Company's licenses. These conditions could have a negative effect on Idaho Power Company's operations, require large capital expenditures and reduce earnings and cash flows.

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- **The cost of complying with environmental regulations can reduce earnings and cash flows.** IDACORP, Inc. and Idaho Power Company are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, natural resources and health and safety. Compliance with these environmental statutes, rules and regulations involves significant capital and operating expenditures. These expenditures could become even more significant in the future if legislation and enforcement policies change. For instance, considerable attention has been focused on carbon dioxide emissions from coal-fired generating plants and their potential role in contributing to global warming. The effects of mercury emissions from coal-fired plants are also being discussed. The adoption of new laws and regulations to implement carbon dioxide, mercury or other emission controls could increase the cost of operating coal-fired generating plants and reduce earnings and cash flows.
- **IDACORP, Inc., IDACORP Energy and Idaho Power Company are subject to costs and other effects of legal and regulatory proceedings, settlements, investigations and claims, including those that have arisen out of the western energy situation.** IDACORP, Inc., IDACORP Energy and Idaho Power Company are involved in a number of proceedings including the California refund proceeding at the Federal Energy Regulatory Commission, which has been settled but which has an appeal pending at the U.S. Court of Appeals for the Ninth Circuit; a refund proceeding affecting sellers of wholesale power in the spot market in the Pacific Northwest, in which the Federal Energy Regulatory Commission directed that no refunds be paid, but which has an appeal pending before the United States Court of Appeals for the Ninth Circuit; efforts by two remaining parties (the City of Tacoma and Wah Chang) to reform or terminate contracts for the purchase of power from IDACORP Energy or other parties claiming violations of state and federal antitrust acts and dysfunctional energy markets as the result of market manipulation; show cause proceedings at the Federal Energy Regulatory Commission, which have been settled but are the subject of motions for rehearing or have been appealed; claims pending before the United States Court of Appeals for the Ninth Circuit that the Federal Energy Regulatory Commission-ordered refund period should have been expanded to include a longer time period, and the reversal by the United States Court of Appeals for the Ninth Circuit of Federal Energy Regulatory Commission rulings that market-based sellers' transactional reports satisfy the Federal Energy Regulatory Commission's filed-rate doctrine requirements as a means of expanding refunds from all sellers of wholesale power, which rulings remain pending before the United States Court of Appeals for the Ninth Circuit on rehearing. To the extent the companies are required to make payments, earnings and cash flows will be negatively affected. It is possible that additional proceedings related to the western energy situation may be filed in the future against IDACORP, Inc., IDACORP Energy or Idaho Power Company.
- **Idaho Power Company's business is subject to substantial governmental regulation and may be adversely affected by increased costs resulting from, or liability under, existing or future regulations or requirements.** Idaho Power Company is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and regulatory audits, including those of the Federal Energy Regulatory Commission, the Environmental Protection Agency, and the public utility commissions in Idaho, Oregon and Wyoming. Some of these regulations are changing or subject to interpretation, and failure to comply may result in penalties or other adverse consequences. Compliance with these requirements directly influences Idaho Power Company's operating environment and may significantly increase Idaho Power Company's operational costs.
- **Pending shareholder litigation could be costly, time consuming and, if adversely decided, result in substantial liabilities.** Two securities shareholder lawsuits consolidated by order dated August 31, 2004 have been filed against IDACORP, Inc. and four of its officers and directors. Securities litigation can be costly, time-consuming and disruptive to normal business operations. Costs below a self-insured retention are not covered by insurance policies. If these lawsuits are resolved against IDACORP, Inc. or settled out of court, the damages or settlement amounts in excess of insurance coverage could have a material adverse effect on the financial position, results of operations or cash flows of IDACORP, Inc.

- **Increased capital expenditures can significantly affect liquidity.** Increases in both the number of customers and the demand for energy require expansion and reinforcement of transmission, distribution and generating systems. If Idaho Power Company does not receive timely regulatory relief, Idaho Power Company will have to rely more on external financing for its future utility construction expenditures. These large planned expenditures may weaken the consolidated financial profile of IDACORP, Inc. and Idaho Power Company. Additionally, a significant portion of Idaho Power Company's facilities were constructed many years ago. Aging equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures. Failure of equipment or facilities used in Idaho Power Company's systems could potentially increase repair and maintenance expenses, purchased power expenses and capital expenditures.

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- **As a holding company, IDACORP, Inc. does not have its own operating income and must rely on the upstream cash flows from its subsidiaries to pay dividends and make debt payments.** IDACORP, Inc. is a holding company and thus its primary assets are shares or other ownership interests of its subsidiaries, primarily Idaho Power Company. Consequently, IDACORP, Inc.'s ability to pay dividends and its ability to service its debt is dependent upon dividends and other payments received from its subsidiaries. IDACORP, Inc.'s subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to IDACORP, Inc., whether through dividends, loans or other payments. The ability of IDACORP, Inc.'s subsidiaries to pay dividends or make distributions to IDACORP, Inc. depends on several factors, including their actual and projected earnings and cash flow, capital requirements and general financial condition, and the prior rights of holders of their existing and future first mortgage bonds and other debt securities.
- **A downgrade in IDACORP, Inc.'s and Idaho Power Company's credit ratings could negatively affect the companies' ability to access capital.** On November 29, 2004, Standard & Poor's Ratings Services, on December 3, 2004, Moody's Investors Service, and on January 24, 2005, Fitch, Inc. each downgraded IDACORP, Inc.'s and Idaho Power Company's credit ratings. On March 27, 2006, Standard & Poor's Ratings Services revised its general corporate credit rating outlooks for IDACORP, Inc. and Idaho Power Company to negative from stable. These downgrades and any future downgrades of IDACORP, Inc.'s or Idaho Power Company's credit ratings could limit the companies' ability to access the capital markets, including the commercial paper markets. In addition, IDACORP, Inc. and Idaho Power Company would likely be required to pay a higher interest rate on existing short-term and variable rate debt and in future financings.
- **Terrorist threats and activities could result in reduced revenues and increased costs.** IDACORP, Inc. and Idaho Power Company are subject to direct and indirect effects of terrorist threats and activities. Potential targets include generation and transmission facilities. The effects of terrorist threats and activities could prevent Idaho Power Company from purchasing, generating or transmitting power and result in reduced revenues and increased costs.
- **Adverse results of income tax audits could reduce earnings and cash flows.** Outcome of ongoing and future income tax audits could differ materially from the amounts currently recorded, and the difference could reduce IDACORP's and Idaho Power Company's earnings and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

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ITEM 2. PROPERTIES

IPC's system is comprised of 17 hydroelectric generating plants located in southern Idaho and eastern Oregon, two natural gas-fired plants located in southern Idaho and interests in three coal-fired steam electric generating plants located in Wyoming, Nevada and Oregon. The system also includes approximately 4,629 miles of high-voltage transmission lines, 23 step-up transmission substations located at power plants, approximately 63,949 miles of distribution lines, 20 transmission substations, eight switching stations and 222 energized distribution substations (excluding mobile substations and dispatch centers).

IPC holds FERC licenses for all of its hydroelectric projects that are subject to federal licensing. These projects and the other generating stations and their capacities are listed below:

Project	Estimated Non-Coincident Maximum Operating Capacity (kW)	Nameplate Capacity (kW)	License Expiration
Hydroelectric Developments:			
Properties subject to federal licenses:			
Lower Salmon	70,000	60,000	2034
Bliss	80,000	75,000	2034
Upper Salmon	39,000	34,500	2034
Shoshone Falls	12,500	12,500	2034
CJ Strike	89,000	82,800	2034
Upper Malad - Lower Malad	24,000	21,770	2035
Brownlee-Oxbow-Hells Canyon	1,398,000	1,166,900	2005(a)
Swan Falls	25,547	25,000	2010
American Falls	112,420	92,340	2025
Cascade	14,000	12,420	2031
Milner	59,448	59,448	2038
Twin Falls	54,300	52,737	2040
Other Hydroelectric:			
Clear Lakes - Thousand Springs	10,400	11,300	
Total Hydroelectric		1,706,715	
Steam and Other Generating Plants:			
Jim Bridger (coal-fired) (b)	706,667	770,501	
Valmy (coal-fired) (b)	260,650	283,500	
Boardman (coal-fired) (b)	58,500	56,050	
Danskin (gas-fired)(c)	76,000	90,000	
Salmon (diesel-internal combustion)	5,500	5,000	
Bennett Mountain (gas-fired)(c)	163,980	172,800	
Total Steam and Other		1,377,851	
Total Generation		3,084,566	

(a) Licensed on an annual basis while application for new multi-year license is pending.

(b) IPC's ownership interests are 33 percent for Jim Bridger, 50 percent for Valmy and 10 percent for Boardman. Amounts shown represent IPC's share.
(c) Maximum operating capacity is based on summer rating at 90 degrees F.
See discussion of relicensing in Part II, Item 7 - "MD&A - REGULATORY MATTERS - Relicensing of Hydroelectric Projects."

At December 31, 2006, the composite average ages of the principal parts of IPC's system, based on dollar investment, were: production plant, 25 years; transmission system and substations, 24 years; and distribution lines and substations, 20 years. IPC considers its properties to be well-maintained and in good operating condition.

IPC owns in fee all of its principal plants and other important units of real property, except for portions of certain projects licensed under the Federal Power Act and reservoirs and other easements. IPC's property is also subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. In addition, IPC's property is subject to minor defects common to properties of such size and character that do not materially impair the value to, or the use by, IPC of such properties.

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Idaho Energy Resources Co. owns a one-third interest in the Bridger Coal Company and coal leases near the Jim Bridger generating plant in Wyoming from which coal is mined and supplied to the plant.

Ida-West holds 50 percent interests in nine operating hydroelectric plants with a total generating capacity of 45 MW. These plants are located in Idaho and California.

See Note 1 to IDACORP's and IPC's Consolidated Financial Statements for a discussion of the property of IDACORP's consolidated Variable Interest Entities.

ITEM 3. LEGAL PROCEEDINGS

See Note 7 to IDACORP's and IPC's Consolidated Financial Statements.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

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EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages and positions of all of the executive officers of IDACORP, Inc. and Idaho Power Company are listed below along with their business experience during the past five years. Mr. J. LaMont Keen and Mr. Steven R. Keen are brothers. There are no other family relationships among these officers, nor is there any arrangement or understanding between any officer and any other person pursuant to which the officer was elected.

J. LAMONT KEEN President and Chief Executive Officer, appointed July 1, 2006. Mr. Keen also serves as President and Chief Executive Officer of Idaho Power Company, appointed November 17, 2005. Mr. Keen was Executive Vice President of IDACORP, Inc., from March 1, 2002 to July 1, 2006, and President and Chief Operating Officer of Idaho Power Company from March 1, 2002 to November 17, 2005. Mr. Keen was Senior Vice President - Administration and Chief Financial Officer of IDACORP, Inc. and Idaho Power Company from May 5, 1999 to March 1, 2002. Mr. Keen also serves on the Board of Directors of both IDACORP, Inc. and Idaho Power Company. Age 54.

DARREL T. ANDERSON Senior Vice President - Administrative Services and Chief Financial Officer of IDACORP, Inc. and Idaho Power Company, appointed July 1, 2004. Mr. Anderson was Vice President, Chief Financial Officer and Treasurer of IDACORP, Inc. and Idaho Power Company from March 1, 2002 to July 1, 2004 and Vice President - Finance and Treasurer of IDACORP, Inc. and Idaho Power Company from May 5, 1999 to March 1, 2002. Age 48.

THOMAS R. SALDIN Senior Vice President, General Counsel and Secretary of IDACORP, Inc. and Idaho Power Company, appointed October 1, 2004. Mr. Saldin was Executive Vice President and General Counsel of Albertson's Inc., a supermarket chain, from January 29, 1999 to his retirement on August 31, 2001. Age 60.

DENNIS C. GRIBBLE Vice President and Chief Information Officer of IDACORP, Inc. and Idaho Power Company, appointed June 1, 2006. Mr. Gribble was Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, from July 15, 2004 to June 1, 2006 and Finance Controller of Idaho Power Company from January 1, 1997 to July 15, 2004. Age 54.

LUCI K. MCDONALD Vice President - Human Resources of IDACORP, Inc. and Idaho Power Company, appointed December 6, 2004. Ms. McDonald was Corporate Staff Director of Human Resources of Boise Cascade Corporation, a forest products company, from September 16, 1999 to November 19, 2004. Age 49.

GREGORY W. PANTER Vice President - Public Affairs of IDACORP, Inc. and Idaho Power Company, appointed April 1, 2001. Age 58.

LORI D. SMITH Vice President - Finance and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, appointed July 15, 2004. Ms. Smith was Director of Strategic Analysis of Idaho Power Company from January 1, 2000 to July 15, 2004. Age 46.

STEVEN R. KEEN Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, appointed June 1, 2006. Mr. Keen is also President of IDACORP Financial Services, appointed September 8, 1998. Age 46.

NAOMI SHANKEL Vice President, Audit and Compliance of IDACORP, Inc. and Idaho Power Company, appointed September 21, 2006. Ms. Shankel was Director, Audit Services of IDACORP, Inc. and Idaho Power Company from July 2003 to September 21, 2006. Ms. Shankel was a member of the Finance Department of Idaho Power Company from April 4, 2001, to July 2003. Age 35.

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JAMES C. MILLER Senior Vice President - Power Supply of Idaho Power Company, appointed July 1, 2004. Mr. Miller was Senior Vice President - Delivery of Idaho Power Company from October 1, 1999 to July 1, 2004. Age 52

DANIEL B. MINOR Senior Vice President - Delivery of Idaho Power Company, appointed July 1, 2004. Mr. Minor was Vice President - Administrative Services & Human Resources of IDACORP, Inc. and Idaho Power Company from November 20, 2003 to July 1, 2004, Vice President - Corporate Services of Idaho Power Company from May 15, 2003 to November 20, 2003, and Director of Audit Services of Idaho Power Company from July 2001 to May 15, 2003. Age 49

JOHN R. GALE Vice President - Regulatory Affairs of Idaho Power Company, appointed March 15, 2001. Age 56

LISA A. GROW Vice President - Delivery Engineering and Operations of Idaho Power Company, appointed July 20, 2005. Ms. Grow was General Manager of Grid Operations and Planning of Idaho Power Company from October 23, 2004 to July 20, 2005, Operations Manager (Grid Ops) of Idaho Power Company from March 2, 2002 to October 23, 2004, and Control Area Operations Leader from October 13, 2001 to March 2, 2002. Age 41

WARREN KLINE Vice President - Customer Service and Regional Operations of Idaho Power Company, appointed July 20, 2005. Mr. Kline was General Manager of Regional Operations of Idaho Power Company from March 2, 2002 to July 20, 2005 and General Manger of Customer Service and Metering from January 9, 1999 to March 2, 2002. Age 51

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

IDACORP's common stock, without par value, is traded on the New York Stock Exchange. On December 31, 2006, there were 15,868 holders of record and the stock price was $38.65 per share.

The outstanding shares of IPC's common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of IPC on October 1, 1998.

The amount and timing of dividends payable on IDACORP's common stock are within the sole discretion of IDACORP's Board of Directors. The Board of Directors reviews the dividend rate quarterly to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency requirements, legislative and regulatory developments affecting the electric utility industry in general and IPC in particular, competitive conditions and any other factors the Board of Directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily IPC.

A covenant under the IDACORP and IPC Credit Facilities described in "MD&A - LIQUIDITY AND CAPITAL RESOURCES - Financing Programs - Credit Facilities" requires IDACORP and IPC to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization of no more than 65 percent at the end of each fiscal quarter. IPC's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would cause their leverage ratios to exceed 65 percent. At December 31, 2006, the leverage ratios for IDACORP and IPC were 51 and 50 percent, respectively.

IPC's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. IPC has no preferred stock outstanding. IPC paid dividends to IDACORP of $51 million, $51 million and $46 million in 2006, 2005 and 2004, respectively.

The following table shows the reported high and low sales price of IDACORP's common stock and dividends paid for 2006 and 2005 as reported in the consolidated transaction reporting system.

	2006 Quarters			
Common Stock, without par value:	**1st**	**2nd**	**3rd**	**4th**
High	$33.28	$35.20	$38.81	$40.17
Low	28.97	32.00	34.00	37.61
Dividends paid per share (cents)	30.0	30.0	30.0	30.0

	2005 Quarters			
Common Stock, without par value:	**1st**	**2nd**	**3rd**	**4th**
High	$30.64	$30.80	$32.05	$31.09
Low	27.32	26.22	28.75	27.46
Dividends paid per share (cents)	30.0	30.0	30.0	30.0

Issuer Purchases of Equity Securities:

None

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Performance Graph

The following performance graph shows a comparison of the five-year cumulative total shareholder return for IDACORP common stock, the S&P 500 Index and the Edison Electric Institute (EEI) Electric Utilities Index. The data assumes that $100 was invested on December 31, 2001, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.

Source: Bloomberg and Edison Electric Institute

	IDACORP	**S & P 500**	**EEI Electric Utilities Index**
2001	$100.00	$100.00	$100.00
2002	65.02	77.91	85.27
2003	83.78	100.24	105.29
2004	89.15	111.14	129.33
2005	89.02	116.59	150.09
2006	121.40	134.99	181.25

The foregoing performance graph and data shall not be deemed "filed" as part of this Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section and should not be deemed incorporated by reference into any other filing of IDACORP or IPC under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent IDACORP or IPC specifically incorporates it by reference into such filing.

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ITEM 6. SELECTED FINANCIAL DATA

IDACORP, Inc.
SUMMARY OF OPERATIONS
(thousands of dollars except per share amounts)

	2006	2005	2004	2003	2002
Operating revenues	$ 926,291	$ 842,864	$ 827,856	$ 823,002	$ 928,800
Operating income	169,704	154,653	106,233	84,062	75,640
Income from continuing operations	100,075	85,716	80,781	49,732	70,377
Diluted earnings per share from continuing operations	2.34	2.02	2.10	1.30	1.86
Dividends declared per share	1.20	1.20	1.20	1.70	1.86
Financial Condition:					
Total assets	$ 3,445,130	$ 3,364,126	$ 3,234,172	$ 3,106,108	$ 3,387,168
Long-term debt	1,023,773	1,039,852	1,058,152	1,013,757	988,268
Financial Statistics:					
Times interest charges earned:					
Before tax (1)	2.78	2.65	1.99	1.48	1.33
After tax (2)	2.54	2.37	2.32	1.77	2.06
Market-to-book ratio (3)	151%	121%	128%	132%	108%
Payout ratio (4)	48%	79%	63%	139%	114%
Return on year-end common equity (5)	9.6%	6.2%	7.2%	5.4%	7.1%
Book value per share (6)	$ 25.65	$ 24.05	$ 23.88	$ 22.61	$ 22.98

The financial statistics listed above are calculated in the following manner:

(1) The sum of interest on long-term debt, other interest expense excluding the allowance for funds used during construction credits (AFDC), and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFDC credits.

(2) The sum of interest on long-term debt, other interest expense excluding AFDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFDC credits.

(3) The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in (6) below.

(4) Dividends paid per common share for the year divided by earnings per diluted share.

(5) Net income divided by total shareholders' equity at the end of the year.

(6) Total shareholders' equity at the end of the year divided by shares outstanding at the end of the year.

In the second quarter of 2006, IDACORP management designated the operations of IDACORP Technologies, Inc. and IDACOMM as assets held for sale. IDACORP's consolidated financial statements reflect the reclassification of the results of these businesses as discontinued operations for all periods presented. Discontinued operations are discussed in more detail in Note 17 to IDACORP's and IPC's Consolidated Financial Statements and later in "MD&A - RESULTS OF OPERATIONS - Non-utility Operations - Discontinued Operations."

IDACORP Energy, a marketer of energy commodities, wound down operations in 2003.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Dollar amounts and Megawatt hours (MWh) are in thousands unless otherwise indicated).

INTRODUCTION:

In Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), the general financial condition and results of operations for IDACORP, Inc. and its subsidiaries (collectively, IDACORP) and Idaho Power Company and its subsidiary (collectively, IPC) are discussed.

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is IPC. IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005, which provides certain access to books and records to the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions and imposes certain record retention and reporting requirements on IDACORP.

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IPC is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. IPC is regulated by the FERC and the state regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co., a joint venturer in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

IDACORP's other subsidiaries include:

IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments;

Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and

IDACORP Energy (IE), a marketer of energy commodities, which wound down operations in 2003.

In the second quarter of 2006, IDACORP management designated the operations of IDACORP Technologies, Inc. (ITI) and IDACOMM as assets held for sale, as defined by Statement of Financial Accounting Standards No. 144. *"Accounting for the Impairment or Disposal of Long-Lived Assets"* (SFAS 144). IDACORP's consolidated financial statements reflect the reclassification of the results of these businesses as discontinued operations for all periods presented. Discontinued operations are discussed in more detail in Note 17 to IDACORP's and IPC's Consolidated Financial Statements and later in the MD&A.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited.

On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc.

While reading the MD&A, please refer to the Consolidated Financial Statements of IDACORP and IPC, which present the financial position at December 31, 2006 and 2005, and the results of operations and cash flows for each company for the years ended December 31, 2006, 2005 and 2004.

FORWARD-LOOKING INFORMATION:

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (Reform Act), IDACORP and IPC are hereby filing cautionary statements identifying important factors that could cause actual results to differ materially from those projected in forward-looking statements (as such term is defined in the Reform Act) made by or on behalf of IDACORP or IPC in this Annual Report on Form 10-K, in presentations, in response to questions or otherwise. Any statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "may result," "may continue" or similar expressions) are not statements of historical facts and may be forward-looking. Forward-looking statements involve estimates, assumptions and uncertainties and are qualified in their entirety by reference to, and are accompanied by, the following important factors, which are difficult to predict, contain uncertainties, are beyond IDACORP's or IPC's control and may cause actual results to differ materially from those contained in forward-looking statements:

- Changes in and compliance with governmental policies, including new interpretations of existing policies, and regulatory actions and regulatory audits, including those of the Federal Energy Regulatory Commission, the Idaho Public Utilities Commission, the Oregon Public Utility Commission, and the Internal Revenue Service with respect to allowed rates of return, industry and rate structure, day-to-day business operations, acquisition and disposal of assets and facilities, operation and construction of plant facilities, provision of transmission services, relicensing of hydroelectric projects, recovery of purchased power expenses, recovery of other capital investments, present or prospective wholesale and retail competition (including but not limited to retail wheeling and transmission costs) and other refund proceedings;
- Changes arising from the Energy Policy Act of 2005;
- Litigation and regulatory proceedings, including those resulting from the energy situation in the western United States, and settlements that influence business and profitability;
- Changes in and compliance with environmental, endangered species and safety laws and policies;
- Weather variations affecting hydroelectric generating conditions and customer energy usage;

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- Over-appropriation of surface and groundwater in the Snake River basin resulting in reduced generation at hydroelectric facilities;
- Construction of power generating, transmission and distribution facilities including inability to obtain required governmental permits and approvals, and risks related to contracting, construction and start-up;
- Operation of power generating facilities including breakdown or failure of equipment, performance below expected levels, competition, fuel supply, including availability, transportation and prices, and transmission;
- Impacts from the potential formation of a regional transmission organization or the development of another transmission group and the dissolution of Grid West;
- Population growth rates and demographic patterns;
- Market demand and prices for energy, including structural market changes;
- Changes in operating expenses and capital expenditures and fluctuations in sources and uses of cash;
- Results of financing efforts, including the ability to obtain financing on favorable terms, which can be affected by factors such as credit ratings and general economic conditions;
- Actions by credit rating agencies, including changes in rating criteria and new interpretations of existing criteria;
- Homeland security, natural disasters, acts of war or terrorism;
- Market conditions that could affect the operations and prospects of IDACORP's subsidiaries or their competitors;
- Increasing health care costs and the resulting effect on medical benefits paid for employees;
- Performance of the stock market and the changing interest rate environment, which affect the amount of required contributions to pension plans, as well as the reported costs of providing pension and other postretirement benefits;
- Increasing costs of insurance, changes in coverage terms and the ability to obtain insurance;
- Changes in tax rates or policies, interest rates or rates of inflation;
- Adoption of or changes in critical accounting policies or estimates; and
- New accounting or Securities and Exchange Commission requirements, or new interpretation or application of existing requirements.

Any forward-looking statement speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

EXECUTIVE OVERVIEW:

2006 Financial Results

IDACORP's earnings for the year were $107 million, up $44 million as compared to 2005. Diluted earnings per share were $2.51, an increase of $1.01 per share as compared to 2005.

The key components of the change in IDACORP's net income are:

- IPC's earnings increased to $94 million, a $22 million or $0.50 per diluted share increase over the prior year. This increase is primarily attributable to:

- Customer growth and increased electricity sales contributed $15 million (net of tax) to earnings. IPC continued to experience strong customer growth, gaining 14,633 new customers in 2006, an increase of 3.2 percent. The increase in electricity sales was primarily a result of record electricity demand during an unusually warm period in May, June, and July.
- Improved operating margins (revenues less net power supply costs) contributed $11 million (net of tax) to earnings, largely as a result of improved hydroelectric generating conditions and a net base rate increase of 1.0 percent on June 1, 2006 (3.2 percent base rate increase effective June 1, 2006, less a one-time base rate increase of 2.2 percent related to a rate case tax settlement that expired on the same date). Improved stream flow conditions increased total system generation. IPC's hydroelectric generation contributed 57 percent of total system generation for 2006, as compared to 46 percent for 2005, and was 49 percent higher than generation in 2005.

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- O&M expenses reduced earnings by $9 million (net of tax) compared to the prior year. The increase is primarily due to higher labor-related expenses resulting from general wage adjustments and attainment of performance targets, higher thermal O&M due to aging thermal plant and equipment and unanticipated outages at the Valmy plant, and increases in other O&M items associated with higher levels of electricity generation, distribution and customer service efforts.
- Income tax expense at IPC was flat year-over-year. Higher earnings before tax increased tax expense by $8 million but was offset by a net $8 million tax benefit that resulted from the settlement of all non-263A (Uniform Capitalization) issues from the 2001-2003 IRS exam. The effective tax rates for 2006 and 2005 were 31.9 percent and 37.9 percent, respectively. Excluding the settlement, IPC's tax rates for 2006 and 2005 would have been substantially the same.
- In 2006, management designated the operations of ITI and IDACOMM as assets held for sale and presented the operations of these entities as discontinued operations on IDACORP's financial statements. Discontinued operations contributed $7 million to earnings in 2006 as compared to a loss of $22 million in the prior year, an increase of $0.69 per diluted share. The improvement was primarily due to a gain on disposal of ITI of $12 million, net of tax, or $0.27 per diluted share. The earnings increase is also attributable to lower operating expenses resulting from the sale of ITI in July 2006 and the phase-out of the broadband over power line business at IDACOMM during the first half of 2006. A $10 million goodwill impairment recorded at IDACOMM during 2005 also impacted the results.

- Earnings at IE decreased from $5 million in 2005 to zero in 2006, a decrease of $0.12 per diluted share. Since 2003, IE has had no operations but has been working to settle outstanding legal actions related to transactions in the California energy markets in 2000 and 2001. The major transaction affecting results in 2005 was an adjustment to an allowance for uncollectible accounts due from California Parties in the California refund proceedings.

- Net loss at the holding company increased $2 million to $6 million as compared to the prior year, or $0.02 per diluted share. The increase in net loss is attributable to higher legal expenses and higher labor-related and stock-based compensation expenses.

- IFS contributed $1 million less to earnings than in the prior year, a decrease of $0.04 per diluted share. The decline in earnings is attributable to higher investment amortization expense and lower tax benefits due to continued aging of investments.

- IDACORP's income tax expense increased $1 million as a result of higher earnings moderated by the offset by the benefit from the 2001-2003 IRS exam settlement.

Business Strategy

IDACORP is focusing on a strategy that emphasizes IPC as IDACORP's core business. IPC continues to experience strong customer growth in its service area, and this corporate strategy recognizes that IPC must make substantial investments in infrastructure to ensure adequate supply and reliable service. IFS and Ida-West remain components of the corporate strategy.

The strategy includes seeking timely rate relief in both the Idaho and Oregon jurisdictions. IPC plans to file in Idaho and Oregon for either asset-specific or general rate relief regularly in upcoming years

The strategy also includes IDACORP's sale of non-core businesses. IDACORP completed the sale of ITI on July 20, 2006, and completed the sale of IDACOMM on February 23, 2007.

Regulatory Matters

General rate case settlement: On June 1, 2006, IPC implemented a 3.2 percent ($18 million annual) increase to its Idaho retail base rates. IPC had filed a general rate case with the IPUC in October 2005, and the IPUC approved a settlement agreement in May 2006. Base rates primarily reflect IPC's cost of providing electrical service to its customers, including equipment, vehicles and infrastructure. IPC's overall allowed rate of return in Idaho increased from 7.85 percent to 8.1 percent.

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Power Cost Adjustment: On June 1, 2006, IPC implemented its annual Power Cost Adjustment (PCA), resulting in a $123.5 million reduction in the rates of Idaho customers. The reduction in rates comes as a direct benefit of the above-average snow pack in the mountains upstream of Brownlee Reservoir and lower-than-forecasted power supply costs in the 2005-2006 PCA year. In years when water is plentiful and IPC can fully utilize its extensive hydroelectric system, power production costs are lower and IPC can pass those benefits to its customers in the form of rate reductions. When water is in short supply, as it was from 2000 through 2005, the higher costs of supplying power by other means also are shared with IPC's customers.

Emission allowances: In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for approximately $81.6 million (before income taxes and expenses) on the open market. After subtracting transaction fees, the total amount of sales proceeds to be allocated to the Idaho jurisdiction is approximately $76.8 million ($46.8 million net of tax, assuming a tax rate of approximately 39 percent). Through allowance year 2006, IPC has approximately 36,000 excess allowances.

Pursuant to the IPUC order, IPC retained 10 percent or approximately $4.7 million after tax of the emission allowance net proceeds as a shareholder benefit. The remaining 90 percent of the sales proceeds ($69.1 million) is to be recorded as a customer benefit and included in the PCA true-up. A carrying charge will be calculated on $42.1 million, the net-of-tax amount allocable to Idaho jurisdiction customers. This customer benefit will be reflected in PCA rates during the June 1, 2007 through May 31, 2008 PCA rate year.

A stipulation is currently before the OPUC which would offset SO_2 emission allowance proceeds against the 2005-2006 balance of Oregon deferred power supply cost.

Load Growth Adjustment Rate: IPC filed a petition with the IPUC in April 2006 requesting modification of one component of its PCA referred to as the Load Growth Adjustment Rate (LGAR). The LGAR subtracts the cost of serving new Idaho retail customers from the power supply costs IPC is allowed to include in its PCA. The LGAR was set at $16.84 per MWh when the PCA began in 1993. This amount was established as the projected marginal cost of serving each new customer and is subtracted from each year's PCA expense. On January 9, 2007, the IPUC issued its final order in this matter. The IPUC maintained the marginal cost methodology and set the new LGAR at $29.41 per MWh. The new rate becomes effective on April 1, 2007 and will first affect customer rates on June 1, 2008.

The impact of the new LGAR on IPC will ultimately be determined by future load growth. Assuming an average 40 MW load growth, the new rate would result in approximately $10.3 million being subtracted from the next PCA, a pre-tax increase of $4.4 million over the current amount. The impact of the new LGAR can be partially offset by IPC through more frequent general rate case filings with the IPUC or from less customer growth. In its order the IPUC stated that it expected IPC to update its load growth adjustment in all future general rate cases.

IRS audit proceedings

On October 13, 2006, the Internal Revenue Service issued its examination report and assessment for IDACORP's 2001-2003 tax years. The IRS and IDACORP were able to settle all issues, with the exception of IPC's capitalized overhead cost method. The federal tax assessment for the settled issues was paid in November 2006 and did not have a material impact on IDACORP's 2006 cash flows. The settlement decreased IDACORP's 2006 income tax expense by $7.5 million as the assessed deficiency was less than the amounts previously accrued. The disallowance of IPC's capitalized overhead cost method for uniform capitalization (the simplified service cost method) resulted in a federal tax assessment of $45 million. IDACORP disagrees with this conclusion and has appealed the issue. In November 2006, IDACORP filed its formal protest, made a refundable deposit of the disputed tax with the IRS to stop the accrual of interest, and requested an appeals conference. Management cannot predict the timing or outcome of this process, but believes that an adequate provision for income taxes and related interest charges has been made for this issue (see "Income Taxes" for a more detailed discussion).

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2006 high temperatures
IPC's service territory, along with much of the western United States, experienced above-normal temperatures during the months of May, June and July 2006. New records were set for cooling degree-days, a measure of temperature impact on customer demand. Due to these above-normal conditions, a new system peak of 3,050 MW was first set on June 27, 2006, and was subsequently surpassed on July 24, 2006, when a new system peak of 3,084 MW was recorded. Since June 27, 2006, the previous system peak of 2,983 MW, which was set in 2002, was met or exceeded 11 times. IPC was able to meet all of its load requirements during these periods of increased demand through its system generation and by increasing the amount of its purchased power.

Integrated Resource Plan
The IRP is prepared and filed every two years with the IPUC and the OPUC. Prior to filing, the IRP requires extensive involvement by IPC, the IPUC Staff, the OPUC Staff, and customer and environmental representatives, as well as input on the cost of various generation technologies. The IRP is the starting point for demonstrating prudence in IPC's resource decisions. The 2006 IRP identified IPC's forecast load and resource situation for the next twenty years, analyzed potential supply-side and demand-side options and identified near-term and long-term actions. The two primary goals of the 2006 IRP were to (1) identify sufficient resources to reliably serve the growing demand for energy service within IPC's service area throughout the 20-year planning period and (2) ensure that the portfolio of resources selected balances cost, risk and environmental concerns. In addition, there were four secondary goals: (1) to give equal and balanced treatment to both supply-side resources and demand-side measures, (2) to involve the public in the planning process in a meaningful way, (3) explore transmission alternatives, and (4) investigate and evaluate advanced coal technologies. The 2006 IRP was submitted to the IPUC in September 2006 and the OPUC in October 2006. A hearing has been set in Oregon for June 2007.

Capital Requirements and Cash Flows
IDACORP estimates that it will spend $877 million on construction expenditures over the next three years. This amount reflects the need for additional resources in order for IPC to supply power to its growing number of customers.

Forecasts indicate that internal cash generation after dividends will provide less than the full amount of total capital requirements for 2007 through 2009. IDACORP and IPC expect to continue financing the utility construction program and other capital requirements with internally generated funds and continued reliance on externally financed capital.

The amount of internal cash generation is dependent primarily upon IPC's cash flows from operations, which are subject to risks and uncertainties relating to weather and water conditions and IPC's ability to obtain rate relief to cover its operating costs and provide a return on investment.

Idaho Water Management Issues
Power generation at the IPC hydroelectric power plants on the Snake River is dependent upon the state water rights held by IPC and the long-term sustainability of the Snake River, tributary spring flows and the Eastern Snake Plain Aquifer that is connected to the Snake River. IPC continues to participate in water management issues in Idaho that may affect those water rights and resources. This includes active participation in the Snake River Basin Adjudication,

a judicial action initiated in 1987 to determine the nature and extent of water use in the Snake River basin, judicial and administrative proceedings relating to the conjunctive management of ground and surface water rights, and management and planning processes intended to reverse declining trends in river, spring, and aquifer levels and address the long-term water resource needs of the state. While none of the pending water management issues are expected to impact IPC's hydroelectric generation in the near term, IPC's ongoing participation in such issues will help ensure that water remains available over the long-term for use at IPC's hydropower projects on the Snake River.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES:

IDACORP's and IPC's discussion and analysis of their financial condition and results of operations are based upon their consolidated financial statements, which have been prepared in accordance with generally accepted accounting principles (GAAP). The preparation of these financial statements requires IDACORP and IPC to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. On an ongoing basis, IDACORP and IPC evaluate these estimates, including those related to rate regulation, benefit costs, contingencies, litigation, asset impairment, income taxes, unbilled revenues and bad debt. These estimates are based on historical experience and on other assumptions and factors that are believed to be reasonable under the circumstances, and are the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. IDACORP and IPC, based on their ongoing reviews, will make adjustments when facts and circumstances dictate.

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IDACORP and IPC believe the following critical accounting policies are important to the portrayal of their financial condition and results of operations and require management's most difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain.

Accounting for Rate Regulation

A regulated company must satisfy the following conditions in order to apply the accounting policies and practices of Statement of Financial Accounting Standards (SFAS) 71, *"Accounting for the Effects of Certain Types of Regulation;"* an independent regulator must set rates; the regulator must set the rates to cover specific costs of delivering service; and the service territory must lack competitive pressures to reduce rates below the rates set by the regulator. SFAS 71 requires companies that meet the above conditions to reflect the impact of regulatory decisions in their consolidated financial statements and requires that certain costs be deferred as regulatory assets until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities and amortized to the income statement as rates to customers are reduced.

IPC follows SFAS 71, and its financial statements reflect the effects of the different rate making principles followed by the jurisdictions regulating IPC. The primary effect of this policy is that IPC has recorded $425 million of regulatory assets and $295 million of regulatory liabilities at December 31, 2006. While IPC expects to fully recover these regulatory assets and return these regulatory liabilities, such recovery is subject to final review by the regulatory entities.

If IPC should determine in the future that it no longer meets the criteria for continued application of SFAS 71, it would be required to write off its regulatory assets and liabilities unless regulators specify some other means of recovery or refund. In the event of deregulation, IPC intends to seek recovery of all of its prudent costs, including stranded costs. Due to the current lack of definitive legislation, IPC cannot predict whether recovery would be successful. If IPC has to write off a material amount of the regulatory assets, it will have a material adverse effect on IPC's results of operations and financial position.

Pension Expense

IPC maintains a qualified defined benefit pension plan covering most employees and an unfunded nonqualified deferred compensation plan for certain senior management employees and directors.

The expenses IDACORP and IPC record for these plans depend on a number of factors, including the provisions of the plans, changing employee demographics, actual returns on plan assets and several assumptions used in the actuarial valuations upon which pension expense is based. The key actuarial assumptions that affect expense are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Management evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends and future expectations. Estimates of future stock market performance, changes in interest rates and other factors are used to develop the actuarial assumptions and are extremely uncertain, and actual results could vary significantly from the estimates.

The assumed discount rate is based on reviews of market yields on high-quality corporate debt. Specifically, IDACORP and IPC utilize data published in the Citigroup Pension Liability Index and apply the rates therein against the projected cash outflows of the plans. The discount rate used to calculate the 2007 pension expense will be increased to 5.85 percent from the 5.60 percent used in 2006.

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. 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.

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Pension expense for these plans totaled $12 million, $10 million, and $10 million for the three years ended December 31, 2006, 2005 and 2004, respectively, including amounts allocated to capitalized labor costs. For 2007, pension expense is expected to total approximately $11 million, which takes into account the increase in the discount rate noted above. No changes were made to the other key assumptions used in the actuarial calculation.

Had different actuarial assumptions been used, pension expense could have varied significantly. The following table reflects the sensitivities associated with changes in certain actuarial assumptions on historical and future pension expense:

	Discount rate		Rate of return	
	2007	2006	2007	2006
	(millions of dollars)			
Effect of 0.5% increase	$ (1.4)	$ (1.7)	$ (2.0)	$ (1.8)
Effect of 0.5% decrease	2.4	3.8	2.0	1.8

No cash contributions were made to the qualified plan in 2004 through 2006, and none are expected in 2007. Under the non-qualified plan, IPC makes payments directly to participants in the plan. Payments averaged approximately $2.5 million per year from 2004 to 2006, and a similar amount is anticipated in 2007.

Please refer to Note 9 of IDACORP's and IPC's Consolidated Financial Statements, which contains additional information about the pension plans.

Contingent Liabilities

There are a number of unresolved issues related to regulatory, legal and tax matters. Contingent liabilities are provided for in accordance with SFAS 5, "*Accounting for Contingencies*." According to SFAS 5, an estimated loss from a loss contingency is charged to income if (a) it is probable that an asset had been impaired or a liability had been incurred at the date of the financial statements and (b) the amount of the loss can be reasonably estimated. Disclosure in the notes to the financial statements is required for loss contingencies not meeting both conditions if there is a reasonable possibility that a loss may have been incurred. Gain contingencies are not recorded until realized.

The companies have made estimates of the ultimate resolution of all such matters, based on the facts and circumstances, opinions of legal counsel and other factors. If the recognition criteria of SFAS 5 have been met, liabilities have been recorded. Estimates of this nature are highly subjective, and the final outcome of these matters could vary significantly from the amounts that have been included in the financial statements.

Impairment of Long-Lived Assets

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 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 impairment must be recognized in the financial statements. Long-lived assets that were evaluated in 2006 include the following:

Grid West Development Costs: In response to FERC Order No. 2000 issued in 1999, several northwest utilities, including IPC, attempted formation of a regional transmission organization called RTO West, which eventually evolved into Grid West. IPC had recorded $1.1 million of loans to Grid West and $2.3 million of deferred internal costs from participating in the development effort. IPC's deferral of development costs was consistent with a 2004 accounting order that IPC received from the FERC. These amounts were initially deferred anticipating future recovery through Grid West tariffs. Grid West was dissolved on April 11, 2006 and IPC no longer expects reimbursement of either amount from Grid West. IPC filed requests with the IPUC and OPUC to recover Grid West costs. The IPUC and OPUC denied recovery of the deferred internal costs, and in the fourth quarter of 2006, IPC wrote off $2 million of the deferred costs. The remaining $0.3 million of FERC related costs were reclassified to regulatory assets in anticipation of recovery from the FERC in future periods.

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Southwest Intertie Project: IPC began developing the Southwest Intertie Project (SWIP) in 1988. IPC's investment consists predominantly of a federal permit for a specific transmission corridor in Nevada and Idaho and also private rights-of-way in Idaho. The SWIP rights-of-way extend from Midpoint substation in south-central Idaho through eastern Nevada to the Dry Lake area northeast of Las Vegas, Nevada. In 2004 the Bureau of Land Management granted a five-year extension to begin construction of a proposed 500kV transmission line within the rights-of-way before December 2009. On March 31, 2005 IPC entered into an agreement with White Pine Energy Associates, LLC (White Pine), an affiliate of LS Power Development, LLC, which provides White Pine a three-year exclusive option to purchase the SWIP rights-of-way from IPC. The option may be exercised in part or as a whole and, if fully exercised, will result in a net pre-tax gain to IPC of approximately $6 million. Based on management expectations regarding SWIP, no impairment has been identified.

Impairment of Equity-Method Investments:
IFS has affordable housing investments with a net book value of $90 million at December 31, 2006, and Ida-West has investments in four joint ventures that own electric power generation facilities. Except for two investments now consolidated in accordance with GAAP these investments are accounted for under the equity method of accounting as described in Accounting Principles Board Opinion No. (APB) 18, "*The Equity Method of Accounting for Investments in Common Stock*." The standard for determining whether impairment must be recorded under APB 18 is whether the investment has experienced a loss in value that is considered an other-than-temporary decline in value. Impairment analyses on these investments were performed in 2006 and no impairment was noted. These estimates required IDACORP to make assumptions about future stream flows, revenues, cash flows and other items that are inherently uncertain. Actual results could vary significantly from the assumptions used, and the impact of such variations could be material.

Unbilled Revenue
IPC's retail revenues include an estimate of electricity delivered that has not been billed at the end of the period. Unbilled revenues estimates are dependent upon a number of inputs that require management's judgment. Unbilled revenue is calculated by taking daily estimates of MWhs delivered and applying information from the meter-reading schedule to estimate the portion of MWhs delivered that have not been billed. These unbilled MWhs are then allocated to the retail customer classes based on historical usage by each class. IPC then records revenue for each customer class based on their respective rates. Due to the seasonal fluctuations of IPC's load, the amount of unbilled revenue increases during the summer and winter months and decreases during the spring and fall.

RESULTS OF OPERATIONS:

This section of the MD&A takes a closer look at the significant factors that affected IDACORP's and IPC's earnings over the last three years. In this analysis, the results of 2006 are compared to 2005 and the results of 2005 are compared to 2004.

The following table presents earnings for IDACORP's segments as well as for the holding company:

	2006	2005	2004

IPC - Utility operations	$	93,929	$	71,839	$	65,785
IDACORP Financial Services		9,509		10,911		13,313
IDACORP Energy		5		4,881		2,162
Ida-West Energy		2,564		2,381		3,089
Holding company expenses		(5,932)		(4,296)		(3,568)
Discontinued operations		7,328		(22,055)		(7,798)
Total Earnings	$	107,403	$	63,661	$	72,983
Average outstanding shares - diluted (000s)		42,874		42,362		38,420
Earnings per diluted share	$	2.51	$	1.50	$	1.90

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Utility Operations

Operating environment: IPC is one of the nation's few investor-owned utilities with a predominantly hydroelectric generating base. Because of its reliance on hydroelectric generation, IPC's generation operations can be significantly affected by weather conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of IPC's hydroelectric facilities, springtime snow pack run-off, rainfall and other weather and stream flow management considerations. During low water years, when stream flows into IPC's hydroelectric projects are reduced, IPC's hydroelectric generation is reduced. This results in less generation from IPC's resource portfolio (hydroelectric, coal-fired and gas-fired) available for off-system sales and, most likely, an increased use of purchased power to meet load requirements. Both of these situations - a reduction in off-system sales and an increased use of more expensive purchased power - result in increased power supply costs. During high water years, increased off-system sales and the decreased need for purchased power reduce net power supply costs.

Operations plans are developed during the year to provide guidance for generation resource utilization and energy market activities (off-system sales and power purchases). The plans incorporate forecasts for generation unit availability, reservoir storage and stream flows, gas and coal prices, customer loads, energy market prices and other pertinent inputs. Consideration is given to when to use IPC's available resources to meet forecast loads and when to transact in the energy market. The allocation of hydroelectric generation between heavy load and light load hours or calendar periods is considered in development of the operating plans. This allocation is intended to utilize the flexibility of the hydroelectric system to shift generation to high value periods, while operating within the constraints imposed on the system. IPC's energy risk management policy, unit operating requirements and other obligations provide the framework for the plans.

Stream flow conditions in 2006 were much improved over 2005 resulting in 9.21 million MWh from IPC hydroelectric facilities in 2006, compared to 6.20 million MWh in 2005. The observed stream flow data released on August 1, 2006, by the National Weather Service's Northwest River Forecast Center indicated that Brownlee reservoir inflow for April through July 2006 was 8.95 million acre-feet (maf), or 142 percent of average. Brownlee reservoir inflow for 2006 totaled 16.98 maf, or 123 percent of average. Storage in selected federal reservoirs upstream of Brownlee as of February 11, 2007, was 122 percent of average. The stream flow forecast released on February 15, 2007 by the National Weather Service's Northwest River Forecast Center predicts that Brownlee reservoir inflow for April through July 2007 will be 3.80 maf, or 60 percent of average.

Generation from thermal plants during 2006 was lower than 2005 due primarily to an unanticipated outage at the Boardman plant and a planned outage at the Valmy plant, of which IPC owns a ten percent and 50 percent interest, respectively. Both units returned to service in June 2006. Additionally, the Bennett Mountain combustion turbine suffered a mechanical failure on July 11, 2006. IPC's investigation has revealed that during construction a bolt was negligently installed by a third party. The bolt came loose, causing extensive mechanical damage. The plant was down from July 12 through September 6, 2006. Total repair costs were approximately $16 million. IPC anticipates that insurance proceeds and/or recovery from the party or parties responsible for the failure will result in substantial reimbursement of these costs.

IPC's system load peaks in the summer and winter, with the larger peak demand occurring in the summer. The new all-time system peak demand was 3,084 megawatts (MW), set on July 24, 2006. The peak winter demand for the year was 2,318 MW on December 18. IPC was able to meet system load requirements and off-system sales requirements and had sufficient system reserves in place. The following table presents IPC's power supply for the last three years:

	MWh				
	Hydroelectric	**Thermal**	**Total System Generation**	**Purchased Power**	**Total**
2006	9,207	7,021	16,228	4,964	21,192
2005	6,199	7,315	13,514	3,894	17,408
2004	6,041	7,303	13,344	4,274	17,618

IPC's median annual hydroelectric generation is 8.25 million MWh, based on median hydrologic conditions for the standardized period of record, 1928 through 2005.

General Business Revenue: The primary influences on electricity sales are weather, customer growth and economic conditions. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Precipitation levels during the agricultural growing season affect sales to customers who use electricity to operate irrigation pumps. Increased precipitation reduces electricity usage by these customers.

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The following table presents IPC's general business revenues, MWh sales, average number of customers and Boise, Idaho weather conditions for the last three years:

	2006	2005	2004
Revenue			
Residential	$ 299,594	$ 299,488	$ 274,313
Commercial	162,391	173,268	164,053
Industrial	102,958	118,259	111,797
Irrigation	71,432	76,255	85,672
Total	$ 636,375	$ 667,270	$ 635,835
MWh			
Residential	5,068	4,760	4,580
Commercial	3,761	3,639	3,561
Industrial	3,475	3,423	3,335
Irrigation	1,635	1,467	1,763
Total	13,939	13,289	13,239
Customers (average)			
Residential	387,707	373,602	360,462
Commercial	59,050	57,146	55,577
Industrial	130	129	120
Irrigation	18,081	17,942	17,306
Total	464,968	448,819	433,465
Heating degree-days	5,195	5,437	5,249
Cooling degree-days	1,209	965	998
Precipitation	12.1"	13.6"	11.6"

Heating and cooling degree-days are a common measure used in the utility industry to analyze the demand for electricity and indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average daily temperature varies from 65 degrees. Each degree of temperature above 65 degrees is counted as one cooling degree-day, and each degree of temperature below 65 degrees is counted as one heating degree-day. Normal heating degree-days and cooling degree-days are 5,727 and 807, respectively.

2006 vs. 2005:

- **Rates:** Rate decreases negatively impacted general business revenue by $66.6 million in 2006 as compared to prior year. A PCA reduction on June 1, 2006, decreased rates by an average of 19.3 percent but was moderated by a net base rate increase of 1.0 percent on June 1, 2006 (3.2 percent base rate increase effective June 1, 2006, less a one-time base rate increase of 2.2 percent related to a rate case tax settlement which expired on the same date). Prior year revenues also included amounts related to a rate case tax settlement and an irrigation load reduction rate adjustment, both of which were recovered from June 2005 to May 2006 (with a corresponding reduction to other revenues);
- **Customers:** General business customer growth improved revenue $18.6 million for the year, as IPC continues to experience customer growth in its service territory. The residential customer base (12-month average) increased 3.8 percent over prior year; and
- **Usage:** Weather variations positively impacted sales by $17.1 million. Conditions were unusually warm in May, June and July compared to the prior year, which had an abnormally cool and wet spring.

2005 vs. 2004:

- **Rates:** Increased average rates resulting from higher base rates that took effect on June 1 in both 2005 and 2004 increased revenues $31 million. This was partially offset by a net reduction in the power cost adjustment rates, which reduced revenue $3 million from 2004. Approximately $16 million of the rate increase represents collection of previously recorded revenues from the irrigation load reduction program and rate case tax settlement. This revenue is offset by a corresponding reduction to other revenues for the same amount;

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- **Customers**: A 3.5 percent increase in average general business customers increased revenue $27 million, as IPC continued to experience strong customer growth in its service territory. IPC added over 16,000 general business customers during the year; and
- **Usage**: Heavy spring precipitation reduced sales to irrigation customers by $17 million. Rainfall during the second quarter of 2005 was double that of 2004. Other weather and usage factors reduced sales to other customers by $6 million.

Off-system sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The following table measures IPC's off-system sales for the last three years:

	2006		2005		2004	
Revenue	$	260,717	$	142,794	$	121,148
MWh sold		5,821		2,774		2,885
Revenue per MWh	$	44.79	$	51.48	$	41.99

2006 vs. 2005: In 2006, the MWh volume sold more than doubled and revenues grew 83 percent. Improved stream flow conditions increased total system generation and electricity available for surplus sales. Revenue from higher sales volumes were moderated by lower prices caused by abundant energy in the region. The volume increase was also impacted by early water year indications suggesting continued drought conditions for 2006, prompting IPC to make forward purchases in conformance with its risk management policy that were subsequently sold. Additional sales activities are the result of conforming to IPC's risk management policy, managing IPC's energy portfolio to meet customer load, and IPC reacting to changes in market conditions to minimize net power supply costs.

2005 vs. 2004: Revenues grew 18 percent due to higher energy prices in 2005. Market prices were higher and more volatile because of oil and gas price increases due to instability in the Middle East and hurricane damage on the Gulf Coast. For the Northwest, continuation of drought conditions in the region compounded the impact of these global problems. Consequently, off-system sales revenue on a per MWh basis increased 23 percent for the year. Off-system sales volumes declined four percent, due primarily to changes in operating conditions and load and stream flow timing, which reduced market sales opportunities.

Other revenues:
The following table presents the components of other revenues:

	2006		2005		2004	
Transmission services and property rental	$	33,526	$	39,012	$	39,839
BPA credit		-		-		4,000
Rate case tax settlement		(4,745)		(2,892)		7,100
Irrigation lost revenues		(5,400)		(8,501)		11,587
Total	$	23,381	$	27,619	$	62,526

2006 vs. 2005: Other revenues decreased $4 million due mainly to the following:

- In 2006, IPC recorded a $1 million provision for rate refund associated with a revised Open Access Transmission Tariff (OATT) filing with the FERC requesting an increase in transmission rates. This matter is discussed further in "REGULATORY MATTERS;"
- In December 2006, IPC recorded a $3 million revenue reduction related to estimated refundable wheeling revenues and a true up of transmission use-of-facility rates from 1998 through 2005.

2005 vs. 2004: Other revenues decreased $35 million due mainly to the following:

- In December 2004, IPC recorded approximately $12 million related to the recovery of lost revenue resulting from IPC's Irrigation Load Reduction Program. The recovery was included as part of IPC's annual PCA beginning on June 1, 2005, and $9 million has been amortized as the amounts are billed. This matter is discussed further in "REGULATORY MATTERS - Deferred Power Supply Costs - Idaho;"

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- In 2004, IPC recognized approximately $7 million of revenue due to the IPUC order approving Settlement No. 1, which relates to the calculation of IPC's taxes for purposes of test year income tax expense in the 2003 Idaho general rate case. As a result of this settlement, IPC recorded a regulatory asset of approximately $12 million from June 1, 2004 through May 31, 2005 ($7 million in 2004 and $5 million in 2005). IPC began collecting this amount beginning in June 2005 with an adjustment to rates and $8 million has been amortized as the amounts are billed; and
- In July 2004, IPC recognized $4 million of revenue from an agreement with the Bonneville Power Administration for the release of 100,000 acre-feet of storage water from Brownlee Reservoir. This amount was included in the June 1, 2005 PCA resulting in a benefit to IPC's Idaho customers.

Purchased power:

		2006		2005		2004
Expense	$	283,440	$	222,310	$	195,642
MWh purchased		4,964		3,894		4,274
Cost per MWh purchased	$	57.10	$	57.09	$	45.77

2006 vs. 2005: Purchased power expense grew 27 percent in 2006. Record high temperatures and electricity demand, particularly in July 2006, led to increased purchases during a period of high market prices. The increase was also impacted by early water year indications suggesting continued drought conditions for 2006, which prompted IPC to make forward purchases in conformance with its risk management policy. Additional purchase activities were the result of managing IPC's energy portfolio to meet customer load and reacting to changes in market conditions to minimize net power supply costs.

2005 vs. 2004: Purchased power expense grew 14 percent due to higher energy prices in 2005. Market prices were higher and more volatile for the reasons discussed above. Purchased power expense on a per MWh basis increased 25 percent for the year. Purchased power volumes declined nine percent. Different operating conditions and system load and stream flow timing led to reduced market purchase activities.

Fuel expense: The following table presents IPC's fuel expenses and generation at its thermal generating plants:

		2006		2005		2004
Fuel expense	$	115,018	$	103,164	$	103,261
Thermal MWh generated		7,021		7,315		7,303
Cost per MWh	$	16.38	$	14.10	$	14.14

2006 vs. 2005: The increase in fuel expense is due primarily to a $12.7 million increase in expense from higher coal and rail transportation costs. The increased cost of coal is due primarily to higher market demand, and the increased rail transportation costs are primarily driven by higher diesel fuel costs, including an adjustable fuel surcharge. Higher natural gas costs of $3 million also contributed to the increase. Generation from the coal fired power plants was down 4 percent due to unplanned outages at Valmy and Boardman. This decrease resulted in a $4 million decrease in fuel expense.

2005 vs. 2004: Fuel expenses and thermal plant volumes were essentially unchanged in 2005 as compared with 2004.

PCA: PCA expense represents the effect of IPC's PCA regulatory mechanism, which is discussed in more detail below in "REGULATORY MATTERS - Deferred Power Supply Costs - Idaho." In 2006, higher electricity purchase volumes, particularly in July during a period of high market prices, coupled with increased coal and natural gas prices, caused an increase in net power supply costs (fuel and purchased power less off-system sales) over the amounts anticipated in the annual PCA forecast. This increase in net power supply costs was partially offset by increased hydroelectric generation in the first half of 2006, resulting in the deferral of costs which will be recovered in subsequent rate years. As the deferred costs are being recovered in rates, the deferred balances are amortized.

In 2005 and 2004 actual net power supply costs also exceeded the amounts anticipated in the annual PCA forecast.

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The following table presents the components of PCA expense:

	2006	2005	2004
Current year net power supply cost deferral	$ (27,094)	$ (30,786)	$ (29,306)
Amortization of prior year authorized balances	(2,432)	27,791	49,190
Settlement agreement	-	-	19,300
Total power cost adjustment	$ (29,526)	$ (2,995)	$ 39,184

Other Operations and Maintenance Expenses:
2006 vs. 2005: Other operations and maintenance expenses increased $15 million due mainly to the following:

- An increase in labor-related expenses of $8.5 million due to higher salaries and incentive-based compensation, partially triggered by improved steamflow conditions and the sale of ITI;
- An increase of $6.3 million in hydroelectric and distribution O&M expenses attributable to better generation conditions and the growth in general business customers;
- An increase of $3.5 million in thermal O&M expense resulting primarily from costs due to an extended outage in 2006 at the Valmy plant; and
- A write off of $2 million in the fourth quarter of 2006 for deferred development costs associated with the attempted formation of Grid West.

These increases were partially offset by a $7.1 million gain resulting from the sale of emission allowances during the year and a $3 million reversal of accrued FERC fees. IPC and several other utilities contested whether certain federal agency charges could be passed on to utilities through FERC fees. A judgment in favor of IPC and the other utilities was finalized in September.

2005 vs. 2004: Other operations and maintenance expenses decreased $15 million due mainly to the 2004 write-off of $9 million related to disallowed items in the Idaho general rate case.

Non-utility Operations

IFS
IFS earned $10 million, $11 million, and $13 million in 2006, 2005 and 2004, respectively, principally from the generation of federal income tax credits and accelerated tax depreciation benefits. The 2004 results included a $2 million gain, net-of-tax, in other income on IDACORP's Consolidated Statements of Income for the sale of its investment in the El Cortez Hotel in San Diego, California.

IFS made $5 million in new investments during 2006 and generated tax credits of $19 million, $20 million and $22 million during 2006, 2005 and 2004, respectively. IFS expects to continue delivering tax benefits at a level commensurate with the ongoing needs of IDACORP.

Discontinued Operations

In the second quarter of 2006, IDACORP management designated the operations of ITI and IDACOMM as assets held for sale. The operations of these entities are presented as discontinued operations in IDACORP's financial statements.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited. IDACORP recorded a gain of $11.5 million, net of tax, or $0.27 per diluted share from this transaction in the third quarter of 2006.

On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc. for proceeds of $10 million. The sale of IDACOMM did not have a material effect on IDACORP's financial position, results of operations or cash flows.

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Income from discontinued operations was $7 million in 2006 and consisted of a loss from operations of $8 million, gain on disposal of ITI of $14 million and an income tax benefit of $1 million. The loss from discontinued operations of $22 million and $8 million for 2005 and 2004 consisted of a loss from operations of $27 million and $13 million, respectively, and an income tax benefit of $5 million for both years. The 2005 results also included a $10 million goodwill impairment charge recorded at IDACOMM.

Energy Marketing
IE recorded net income of $0 million, $5 million and $2 million in 2006, 2005 and 2004, respectively.

In 2003, IE wound down its power marketing operations, closed its business locations and sold its forward book of electricity trading contracts to Sempra Energy Trading. Since that time, IE has had no operations but has been working to settle outstanding legal matters surrounding transactions in the California energy markets in 2000 and 2001. These matters are discussed in "LEGAL AND ENVIRONMENTAL ISSUES - Legal and Other Proceedings."

Net income increased from $2 million in 2004 to $5 million in 2005, due primarily to a $9.5 million adjustment to an allowance for uncollectible accounts recorded in the fourth quarter of 2005. This adjustment was based on management's assessment of the negotiations to settle California refund proceedings discussed in "LEGAL AND ENVIRONMENTAL ISSUES - Legal and Other Proceedings."

The major transaction affecting results in 2004 was $5 million of gains on settlements of legal disputes.

Ida-West
Ida-West recorded net income of $3 million, $2 million and $3 million in 2006, 2005 and 2004, respectively. Ida-West continues to manage its independent power projects.

In 2003 a $2.6 million bad debt reserve was established on a note receivable from a partner in one of Ida-West's joint ventures. No adjustments were made to this reserve in 2006 or 2004, but in 2005 the reserve was reduced by $0.7 million based on updated estimates of collectibility.

Income Taxes
FIN 48: In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*" (FIN 48), to create a single model to address accounting for uncertainty in tax positions. FIN 48 prescribes a minimum recognition threshold that a tax position is required to meet before being recognized in a company's financial statements and also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006.

IDACORP and IPC will adopt FIN 48 in the first quarter of 2007, as required. The cumulative effect of adopting FIN 48 will be recorded as an adjustment to 2007 opening retained earnings. IDACORP and IPC have not yet completed their evaluation of the effects the adoption of FIN 48 will have on their financial positions or results of operations.

Status of audit proceedings: In March 2005, the Internal Revenue Service (IRS) began its examination of IDACORP's 2001-2003 tax years. On October 13, 2006, the IRS issued its examination report and assessment for those years. With the exception of IPC's capitalized overhead costs method, discussed below, the IRS and IDACORP were able to settle all issues. The $1.6 million federal tax assessment for the settled issues was paid in November 2006. Interest charges and state income taxes have been accrued and are expected to be paid during 2007. Settlement of the agreed issues decreased 2006 income tax expense by $5.6 million at IDACORP and $6.2 million at IPC as the assessed deficiency was less than amounts previously accrued.

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The IRS disallowed IPC's capitalized overhead cost method for uniform capitalization (the simplified service cost method) on the basis that IPC's self-constructed assets were not produced on a "routine and repetitive" basis as defined by Rev. Rul. 2005-53. The disallowance resulted in a federal tax assessment of $45 million. IDACORP disagreed with this conclusion and in November 2006 filed its formal protest and request for an appeals conference. Also in November 2006, IDACORP made a refundable deposit of the disputed tax with the IRS to stop the accrual of interest. In December 2006, the IRS examination team filed its rebuttal to IDACORP's protest. In January 2007, IDACORP was notified that its case has been assigned to the IRS Appeals Office. IDACORP cannot predict the timing or outcome of this process, but believes that an adequate provision for income taxes and related interest charges has been made for this issue.

The simplified service cost method was also used for IPC's 2004 tax year. While 2004 is not currently under examination, it is likely the IRS will take the same position for 2004 as it did for 2001-2003; however, it is not likely that this position will result in a federal income tax assessment primarily due to the mitigating effect of accelerated tax depreciation.

On July 7, 2006, the IRS issued its examination report for Bridger Coal Company's 2001-2003 tax years. Bridger Coal is a partnership investment owned one-third by IPC. The audit resulted in net favorable adjustments to Bridger Coal's tax returns for those years. As a result of the settlement, IDACORP and IPC were able to decrease 2006 income tax expense by $1.9 million.

In 2004, IDACORP completed settlement of all issues related to the IRS's examination of its federal income tax returns for the years 1998 through 2000. Concurrently, IPC settled federal income tax deficiencies for the years 1999 and 2000 related to its partnership investment in Bridger Coal Company. Applicable state tax return amendments were completed in 2004 and settled. Finalization of these examinations resulted in deficiencies that were less than previously accrued, enabling IDACORP to decrease income tax expense by $1.7 million in 2004.

Capitalized overhead costs: Generally, section 263A of the Internal Revenue Code of 1986, as amended, requires the capitalization of all direct costs and indirect costs, including mixed service costs, which directly benefit or are incurred by reason of the production of property by a taxpayer. The simplified service cost method, a "safe harbor" method, is one of the methods provided by the section 263A treasury regulations for the calculation of mixed service cost capitalization. IPC adopted the simplified service cost method for both the self-construction of utility plant and production of electricity beginning with its 2001 federal income tax return.

On August 2, 2005, the IRS and the Treasury Department issued guidance interpreting the meaning of "routine and repetitive" for purposes of the simplified service cost and simplified production methods of the Internal Revenue Code section 263A uniform capitalization rules. The guidance was issued in the form of a revenue ruling (Rev. Rul. 2005-53) which is effective for all open tax years ending prior to August 2, 2005, and proposed and temporary regulations (the "Temporary Regulations") which are effective for tax years ending on or after August 2, 2005. Both pieces of guidance take a more restrictive view of the definition of self-constructed assets produced by a taxpayer on a "routine and repetitive" basis than did treasury regulations in effect at the time IPC changed to the simplified service cost method.

For IPC, the simplified service cost method produced a current tax deduction for costs capitalized to electricity production that are capitalized into fixed assets for financial accounting purposes. Deferred income tax expense had not been provided for this deduction because the prescribed regulatory tax accounting treatment does not allow for inclusion of such deferred tax expense in current rates. Rate regulated enterprises are required to recognize such adjustments as regulatory assets if it is probable that such amounts will be recovered from customers in future rates.

As discussed in "Status of Audit Proceedings" above, the IRS has disallowed IPC's use of the simplified service cost method for the tax years 2001-2003 on the basis of Rev. Rul. 2005-53. As a result, the IRS has assessed a $45 million tax liability. IDACORP is in the process of appealing the IRS's assessment. Because of the nature of the issue, IDACORP's exposure with respect to this matter may be less than the tax assessed plus applicable interest charges. Additionally, after resolution IDACORP will likely amend its 2005 federal income tax return and its 2005 method change application to account for the effects that such resolution has on IPC's new uniform capitalization method (discussed below). This amendment is not expected to have a material negative impact on IDACORP's or IPC's consolidated financial position, results of operations, or cash flows.

With respect to tax year 2005 and future tax years, the Temporary Regulations, as drafted, preclude IPC from using the simplified service cost method for its self-constructed assets. Under the Temporary Regulations, IPC is required to use another allowable section 263A method for its indirect costs, including mixed service costs. As a result of the Temporary Regulations, IPC made changes to its overall section 263A uniform capitalization method of accounting. In September 2006, the changes were adopted with an automatic method change request included in IDACORP's 2005 federal income tax return. The uniform capitalization methodology adopted for 2005 and subsequent years involves the use of the specific identification, burden rate, and step-allocation methods of accounting. The methods used are allowable under both the final and temporary section 263A regulations.

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As with the simplified service cost method, the new uniform capitalization methodology produces an annual tax deduction for costs that are not required to be capitalized under section 263A as well as costs capitalized into the production of electricity. The method, while producing a beneficial result, is not as favorable as the simplified service cost method. Changing the uniform capitalization method resulted in a net charge to IPC's 2006 income tax expense of $6.1 million. The estimated 2006 tax deduction produced a $3.3 million tax benefit for the year. The change in method did not have a material effect on IDACORP's or IPC's 2006 cash flows. The accounting and regulatory treatment for the new method is the same as previously used for the simplified service cost method.

LIQUIDITY AND CAPITAL RESOURCES:

Discontinued operations

Cash flows from discontinued operations are included with the cash flows from continuing operations in IDACORP's Consolidated Statements of Cash Flows. The cash flows of IDACORP's discontinued operations have reduced net cash provided by operating activities and increased net cash used in investing activities, except for the cash received in 2006 from the sale of ITI. The absence of cash flows from these discontinued operations is expected to positively impact liquidity and capital resources in future periods.

Operating Cash Flows

IDACORP's and IPC's operating cash flows for 2006 were $170 million and $131 million, respectively. These amounts were an increase of $8 million and decrease of $35 million compared to 2005. The following are significant items that affected operating cash flows in 2006:

- Income tax payments increased in 2006 due to the timing of and increases in taxable income, including the timing effect of cash received in the fourth quarter of 2005 from the sale of approximately $70 million of excess SO_2 emission allowances.
- In 2006, IE collected $13 million of amounts receivable from the Cal ISO and CalPX, and collected $10 million that it had deposited on margin with a counterparty in 2005.

IDACORP's and IPC's operating cash flows for 2005 were $161 million and $166 million, respectively, decreases of $33 million and $32 million compared to 2004. The decreases were mainly related to:

- A $19 million reduction in distributions from the Bridger Coal joint venture, as Bridger is retaining cash to fund increased capital expenditures for conversion to underground mining.
- Timing of cash disbursements made in 2005 for December 2004 payable balances, including $9 million in employee incentive compensation paid during the first quarter of 2005.

IDACORP's operating cash flows are driven principally by IPC. General business revenues and the costs to supply power to general business customers have the greatest impact on IPC's operating cash flows, and are subject to risks and uncertainties relating to weather and water conditions and IPC's ability to obtain rate relief to cover its operating costs and provide a return on investment.

Investing Cash Flows

IPC's construction expenditures were $222 million in 2006, $186 million in 2005 and $190 million in 2004. IPC is experiencing a cycle of heavy infrastructure investment needed to address continued customer growth, peak demand growth, and aging plant and equipment.

In 2005 and 2006, sales of emission allowances provided investing cash of approximately $82 million before taxes and expenses. Pursuant to negotiations with the IPUC, IPC will return approximately $69 million to Idaho ratepayers starting in June 2007. See further discussion in "REGULATORY MATTERS - Emission Allowances."

In November 2006, IDACORP made a refundable deposit of $45 million with the IRS related to a disputed income tax assessment. See further discussion in "RESULTS OF OPERATIONS - Income Taxes."

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Financing Cash Flows

Debt issuances: On October 3, 2006, IPC completed a tax-exempt bond financing in which Sweetwater County, Wyoming issued and sold $116.3 million aggregate principal amount of its Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2006. The bonds will mature on July 15, 2026. The $116.3 million in proceeds were loaned by Sweetwater County to IPC pursuant to a Loan Agreement, dated as of October 1, 2006, between Sweetwater County and IPC (the Loan Agreement). On October 10, 2006, the proceeds of the new bonds, together with certain other moneys of IPC, were used to refund Sweetwater County's Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 1996A, Series 1996B and Series 1996C totaling $116.3 million. The regularly scheduled principal and interest payments on the Series 2006 bonds, and principal and interest payments on the bonds upon mandatory redemption on determination of taxability, are insured by a financial guaranty insurance policy issued by AMBAC Assurance Corporation. IPC and AMBAC have entered into an Insurance Agreement, dated as of October 3, 2006, pursuant to which IPC has agreed, among other things, to pay certain premiums to AMBAC and to reimburse AMBAC for any payments made under the policy. In order to secure its obligation to make principal and interest payments on the loan made to IPC, IPC issued and delivered to a trustee IPC's First Mortgage Bonds, Pollution Control Series C, in a principal amount equal to the principal amount of the new bonds.

On August 26, 2005, IPC issued $60 million of 5.30% First Mortgage Bonds due 2035, Secured Medium-Term Notes, Series F. The proceeds of the issuance were used to repay the $60 million, 5.83% First Mortgage Bonds that matured on September 9, 2005.

Equity issuances: On December 15, 2005, IDACORP entered into a Sales Agency Agreement with BNY Capital Markets, Inc. (BNYCMI). Under the terms of the Sales Agency Agreement, IDACORP may offer and sell up to 2,500,000 shares of its common stock, from time to time in at the market offerings through BNYCMI, as IDACORP's agent for such offer and sale. In the fourth quarter of 2006, IDACORP issued 536,518 shares under this program, for net proceeds of $21 million.

In April 2005, with the goal of adding additional common equity to its capital structure, IDACORP began using original issue common stock in its Dividend Reinvestment and Stock Purchase Plan, rather than purchasing this stock on the open market. Beginning in August 2005, IDACORP also began using original issue common stock for its 401(k) plan. Under these plans, IDACORP issued 244,756 shares in 2006 and 203,253 shares in 2005, for proceeds of $9 million and $6 million, respectively.

IDACORP issued 406,623 shares in 2006 and 16,400 shares in 2005 in connection with the exercise of stock options, for proceeds of $12 million and $0.4 million, respectively.

Capital Requirements

The following table presents IDACORP's and IPC's expected capital requirements from 2007 through 2009:

	2007	**2008-2009**
	(millions of dollars)	

IPC capital expenditures:		
Hydroelectric generation:		
Additions and upgrades	$ 6	$ 57
Environmental (including relicensing)	19	31
Thermal generation		
Additions and upgrades*	87	101
Environmental	11	13
Total generating facilities	123	202
Transmission lines and substations	42	111
Distribution lines and substations	81	151
General	40	78
IPC construction expenditures	286	542
Other IPC	13	1
Total IPC	299	543
Other	8	27
Total IDACORP	$ 307	$ 570

* Excludes $20 - $50 million potential impact of coal-fired resources (see discussion below)

Variations in the timing and amounts of capital expenditures will result from regulatory and environmental factors, load growth, other resource acquisition needs and the timing of relicensing expenditures.

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Utility Construction Program: IPC is experiencing a cycle of heavy infrastructure investment needed to address continued customer growth, peak demand growth, and aging plant and equipment. IPC's aging hydroelectric facilities require continuing upgrades and component replacement. In addition, costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. Continuing load growth also requires that IPC add to its transmission system and distribution facilities to provide new service and to maintain reliability. Planned expenditures include distribution and high-voltage transmission lines for new customers and several lines.

As a result, IPC expects to spend $828 million in construction expenditures from 2007 to 2009. The 2007 - 2009 utility construction expenditure forecast includes: (1) $77 million of construction costs for a 160-MW combustion turbine peaking resource expected to be operational in mid-2008; (2) $40 million for an upgrade to the Shoshone Falls hydroelectric facility expected to be operational in 2011; and (3) $50 million for hydroelectric relicensing.

IPC's Integrated Resource Plan identifies two 250-MW coal-fired resources utilizing pulverized coal and coal gasification technologies needed in 2013 and 2017. The 2007 - 2009 estimates of capital expenditures exclude the potential impact related to the construction or acquisition of these coal-fired resources and related transmission capacity. The development of coal resources requires very long lead times with significant expenditures spread over many years making accurate estimates difficult. At this time and subject to further evaluation and screening, IPC estimates that $20 million to $50 million could be spent from 2007 to 2009 for the development of these projects. IPC will continue to review and update its options and will evaluate financing strategies to fund these capital requirements. See further discussion in "REGULATORY MATTERS - Integrated Resource Plan" and "REGULATORY MATTERS - Relicensing of Hydroelectric Projects."

IPC has no nuclear involvement and its future construction plans do not include development or ownership of any nuclear generation.

Other Capital Requirements: Most of IDACORP's non-regulated capital expenditures relate to IFS's investments in affordable housing developments that help lower IDACORP's income tax liability.

Internal cash generation after dividends is expected to provide less than the full amount of total capital requirements for 2007 through 2009. IDACORP's internally generated cash after dividends is expected to provide approximately 50 percent of 2007 capital requirements excluding mandatory or optional principal payments on debt obligations. Excluding the ratepayer emission refunds, IDACORP's internally generated cash after dividends is expected to provide approximately 60 percent of 2007 capital requirements. IDACORP and IPC expect to continue financing capital requirements with internally generated funds and externally financed capital.

Financing Programs

IDACORP's consolidated capital structure consisted of common equity of 49 percent and debt of 51 percent at December 31, 2006.

Shelf Registrations: IDACORP currently has $658 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock. IPC currently has in place one shelf registration statement that can be used for the issuance of an aggregate principal amount of $240 million of first mortgage bonds (including medium-term notes) and unsecured debt. See Note 4 to IDACORP's and IPC's Consolidated Financial Statements for more information regarding long-term financing arrangements.

Credit Facilities: IDACORP has a $150 million five-year credit agreement that terminates on March 31, 2010 (the IDACORP Facility). The IDACORP Facility, which is used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $150 million, provided that the aggregate amount of the standby letters of credit may not exceed $75 million.

IPC has a $200 million five-year credit agreement that terminates on March 31, 2010 (the IPC Facility). The IPC Facility, which is used for general corporate purposes and commercial paper back-up, provides for the issuance of loans and standby letters of credit not to exceed the aggregate principal amount of $200 million, provided that the aggregate amount of the standby letters of credit may not exceed $100 million.

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Both the IDACORP Facility and the IPC Facility have similar terms and conditions. Under the terms of the facilities IDACORP and IPC may borrow floating rate advances and Eurodollar rate advances. The floating rate is equal to the higher of (i) the prime rate announced by Wachovia Bank or its parent and (ii) the sum of the federal funds effective rate for such day plus 1/2 percent per annum, plus, in each case, an applicable margin. The Eurodollar rate is based upon the British Bankers' Association interest settlement rate for deposits in U.S. dollars published on the Telerate Page 3750 (or any successor page) as adjusted by the applicable reserve requirement for Eurocurrency liabilities imposed under Regulation D of the Board of Governors of the Federal Reserve System, for periods of one, two, three or six months plus the applicable margin. The margin is based the applicable company's rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody's and S&P. The margin for the floating rate advances is zero percent unless the applicable company's rating falls below Baa3 from Moody's or BBB- from S&P, at which time it would equal 0.50 percent. The margin for Eurodollar rate advances ranges from 0.27 percent to 0.875 percent depending upon the credit rating. In addition to the margin, if the outstanding aggregate credit exposure exceeds 50 percent of the facility amount, IDACORP or IPC, as applicable, would pay a utilization fee ranging from 0.10 percent to 0.125 percent on outstanding loans depending on the credit rating. At December 31, 2006, the applicable margin under the IDACORP Facility and the IPC Facility was zero percent for floating rate advances and 0.425 percent for Eurodollar rate advances and 0.125 percent for a utilization fee. A facility fee, payable quarterly, is calculated on the average daily aggregate commitment of the lenders under the relevant credit facility and is also based on the applicable company's rating from Moody's or S&P as indicated above. At December 31, 2006, the facility fee under each facility was 0.15 percent.

In connection with the issuance of letters of credit, IDACORP and IPC, as applicable, must pay (i) a fee equal to the applicable margin for Eurodollar rate advances on the average daily undrawn stated amount under such letters of credit, payable quarterly in arrears, (ii) a fronting fee at a per annum rate of 0.125 percent on the average daily undrawn stated amount under each letter of credit, payable quarterly in arrears and (iii) documentary and processing charges in accordance with the letter of credit issuer's standard schedule for such charges.

A ratings downgrade would result in an increase in the cost of borrowing and of maintaining letters of credit, but would not result in any default or acceleration of the debt under either the IDACORP Facility or the IPC Facility.

The events of default under both the IDACORP Facility and the IPC Facility include (i) nonpayment of principal when due and nonpayment of reimbursement obligations under letters of credit within one business day after becoming due and nonpayment of interest or other fees within five days after becoming due, (ii) materially false representations or warranties made on behalf of the applicable company or any of its subsidiaries on the date as of which made, (iii) breach of covenants, subject in some instances to grace periods, (iv) voluntary and involuntary bankruptcy of the applicable company or any material subsidiary, (v) the non-consensual appointment of a receiver or similar official for the applicable company or any of its material subsidiaries or any substantial portion (as defined in the applicable facility) of its property, (vi) condemnation of all or any substantial portion of the property of the applicable company or its subsidiaries, (vii) default in the payment of indebtedness in excess of $25 million or a default by the applicable company or any of its subsidiaries under any agreement under which such debt was created or governed which will cause or permit the acceleration of such debt or if any of such debt is declared to be due and payable prior to its stated maturity, (viii) the applicable company or any of its subsidiaries not paying, or admitting in writing its inability to pay, its debts as they become due, (ix) the acquisition by any person or two or more persons acting in concert of beneficial ownership (within the meaning of Rule 13d-3 of the Securities Exchange Act of 1934) of 20 percent or more of the outstanding shares of voting stock of the applicable company, (x) the failure of

IDACORP to own free and clear of all liens, all of the outstanding shares of voting stock of IPC, (xi) unfunded liabilities of all single employer plans under the Employee Retirement Income Security Act of 1974 exceeding $50 million and (xii) the applicable company or any subsidiary being subject to any proceeding or investigation pertaining to the release of any toxic or hazardous waste or substance into the environment or any violation of any environmental law (as defined in the applicable facility) which could reasonably be expected to have a material adverse effect (as defined in the applicable facility). A default or an acceleration of indebtedness of IPC in excess of $25 million, including indebtedness under the IPC Facility will result in a cross default under the IDACORP Facility.

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Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or IPC or the appointment of a receiver, the obligations of the lenders to make loans under the facility and of the letter of credit issuer to issue letters of credit will automatically terminate and all unpaid obligations will become due and payable. Upon any other event of default, the lenders holding 51 percent of the outstanding loans or 51 percent of the aggregate commitments (required lenders) or the administrative agent with the consent of the required lenders may terminate or suspend the obligations of the lenders to make loans under the facility and of the letter of credit issuer to issue letters of credit under the facility or declare the obligations to be due and payable. IDACORP and IPC will also be required to deposit into a collateral account an amount equal to the aggregate undrawn stated amount under all outstanding letters of credit and the aggregate unpaid reimbursement obligations thereunder.

If there is a ratings downgrade below investment grade (BBB- or higher by S&P and Baa3 or higher by Moody's), then IPC's authority for continuing borrowings under its regulatory approvals issued by the IPUC and the Oregon Public Utility Commission (OPUC) must be extended or renewed during the occurrence of the ratings downgrade. The Oregon statutes, however, permit the issuance or renewal of indebtedness maturing not more than one year after the date of such issue or renewal without approval of the OPUC. In an order issued May 6, 2005, the IPUC clarified that IPC's authority will not terminate but will continue for a period of 364 days from any downgrade below investment grade.

At December 31, 2006, no loans were outstanding under the IDACORP Facility or the IPC Facility.

Debt Covenants: The IDACORP Facility and the IPC Facility each contain a covenant requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization of no more than 65 percent as of the end of each fiscal quarter. At December 31, 2006, the leverage ratios for IDACORP and IPC were 51 and 52 percent, respectively. At December 31, 2006, IDACORP was in compliance with all other covenants of the IDACORP Facility and IPC was in compliance with all other covenants of the IPC Facility. Both the IDACORP Facility and the IPC Facility contain additional covenants including:

(i) prohibitions against: investments and acquisitions by the applicable company or any subsidiary without the consent of the required lenders subject to exclusions for investments in cash equivalents or securities of the applicable company; investments by the applicable company and its subsidiaries in any business trust controlled, directly or indirectly, by the applicable company to the extent such business trust purchases securities of the applicable company; investments and acquisitions related to the energy business or other business of the applicable company and its subsidiaries not exceeding $500 million in the aggregate at any one time outstanding (provided that investments in non-energy related businesses do not exceed $150 million); and investments by the applicable company or a subsidiary in connection with a permitted receivables securitization (as defined in the facility);

(ii) prohibitions against the applicable company or any material subsidiary merging or consolidating with any other person or selling or disposing of all or substantially all of its property to another person without the consent of the required lenders, subject to exclusions for mergers into or dispositions to the applicable company or a wholly owned subsidiary and dispositions in connection with a permitted receivables securitization;

(iii) restrictions on the creation of certain liens by the applicable company or any material subsidiary subject to exceptions, including the lien of IPC's first mortgage indebtedness; and

(iv) prohibitions on any material subsidiary of the applicable company entering into any agreement restricting its ability to declare or pay dividends to the applicable company except pursuant to a permitted receivables securitization.

Credit Ratings

S&P: On March 27, 2006, S&P announced that it had revised its general corporate credit rating outlooks for IDACORP and IPC to negative from stable. All other S&P credit ratings for IDACORP and IPC were reaffirmed. S&P stated that the negative outlooks reflect the potential for weakened financial metrics as a result of several factors, including possible passage of the water diversion legislation and uncertainty regarding the federal and state tax treatment and allocation of previous refunds of about $75 million (see "INCOME TAXES - Capitalized Overhead Costs" above and Note 2 to IDACORP's and IPC's Condensed Consolidated Financial Statements for a full discussion of capitalized overhead costs). A less substantial concern was the uncertainty regarding the relicensing of the Hells Canyon Complex.

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Access to capital markets at a reasonable cost is determined in large part by credit quality. These downgrades have increased the cost of new debt and other issued securities. The following outlines the current S&P, Moody's and Fitch ratings of IDACORP's and IPC's securities:

	S&P		**Moody's**		**Fitch**	
	IPC	**IDACORP**	**IPC**	**IDACORP**	**IPC**	**IDACORP**
Corporate Credit Rating	BBB+	BBB+	Baa 1	Baa 2	None	None
Senior Secured Debt	A-	None	A3	None	A-	None
Senior Unsecured Debt	BBB (prelim)	BBB (prelim)	Baa 1	Baa 2	BBB+	BBB
Short-Term Tax-Exempt Debt	BBB/A-2	None	Baa 1/VMIG-2	None	None	None
Commercial Paper	A-2	A-2	P-2	P-2	F-2	F-2
Credit Facility	None	None	Baa 1	Baa 2	None	None
Rating Outlook	Negative	Negative	Stable	Stable	Stable	Stable

These security ratings reflect the views of the rating agencies. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Off-Balance Sheet Arrangements

The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. These obligations mandate that mine property be restored consistent with specific standards and the approved reclamation plan. The mining operations at the Bridger Coal Company are subject to these reclamation and closure requirements. 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, 2006. Bridger Coal has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs and expects 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.

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Contractual Obligations

The following table presents IDACORP's and IPC's contractual cash obligations for the respective periods in which they are due:

	Total		Payment Due by Period 2007		2008-2009		2010-2011		Thereafter
			(millions of dollars)						
IPC:									
Long-term debt (a)	$	987	$	81	$	82	$	122	$ 702
Future interest payments (b)		771		56		98		81	536
Operating leases (c)		15		3		6		1	5
Purchase obligations:									
Cogeneration and small power production		1,422		45		153		159	1,065
Fuel supply agreements		131		54		59		7	11
Purchased power & transmission (d)		123		80		24		6	13
Other (e)		162		91		29		12	30
Total purchase obligations		1,838		270		265		184	1,119
Pension and postretirement plans (g)		72		6		13		14	39
Other long-term liabilities - IPC		6		4		2		-	-
Total IPC	$	3,689	$	420	$	466	$	402	$ 2,401
Other:									
Long-term debt (a)(f)		40		14		16		3	7
Future interest payments (b)(f)		9		2		2		1	4
Operating leases (f)		9		2		2		1	4
Total IDACORP	$	3,747	$	438	$	486	$	407	$ 2,416

(a) For additional information, see Note 4 to IDACORP's and IPC's Consolidated Financial Statements.

(b) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2006

(c) Approximately $10 million of the obligations included in the detail of operating leases have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, have been included in the table for presentation purposes

(d) Approximately $6 million of the obligations included in the detail of purchased power and transmission have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, have been included in the table for presentation purposes.

(e) Approximately $4 million of the amounts in other purchase obligations can be cancelled without penalty. Additionally, approximately $45 million of the contracts do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, have been included in the table for presentation purposes

(f) Amounts include the obligations of IDACORP's subsidiaries other than IPC, which is shown separately.

(g) Based on current assumptions, no pension contributions will be required during the next five years. IPC cannot estimate contributions beyond 2011 at this time. Amounts include 10 years of postretirement and non-qualified pension contributions.

Environmental Regulation Costs: IPC anticipates $19 million in annual operating costs for environmental facilities during 2007. Hydroelectric facility expenses account for $12 million of this total and $7 million is related to thermal plant operating expenses. From 2008 through 2009, total environmental related operating costs are estimated to be $50 million. Expenses related to the hydroelectric facilities are expected to be $35 million and thermal plant expenses are expected to total $15 million during this period.

LEGAL AND ENVIRONMENTAL ISSUES:

Legal and Other Proceedings

Shareholder Lawsuit: On May 26, 2004 and June 22, 2004, respectively, two shareholder lawsuits were filed against IDACORP and certain of its directors and officers. The lawsuits, captioned Powell, et al. v. IDACORP, Inc., et al. and Shorthouse, et al. v. IDACORP, Inc., et al., raised largely similar allegations. The lawsuits were putative class actions brought on behalf of purchasers of IDACORP stock between February 1, 2002 and June 4, 2002, and were filed in the U.S. District Court for the District of Idaho. The named defendants in each suit, in addition to IDACORP, are Jon H. Miller, Jan B. Packwood, J. LaMont Keen and Darrel T. Anderson.

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The complaints alleged that, during the purported class period, IDACORP and/or certain of its officers and/or directors made materially false and misleading statements or omissions about the company's financial outlook in violation of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as amended, and Rule 10b-5, thereby causing investors to purchase IDACORP's common stock at artificially inflated prices. More specifically, the complaints alleged that IDACORP failed to disclose and misrepresented the following material adverse facts which were known to defendants or recklessly disregarded by them: (1) IDACORP failed to appreciate the negative impact that lower volatility and reduced pricing spreads in the western wholesale energy market would have on its marketing subsidiary, IE; (2) IDACORP would be forced to limit its origination activities to shorter-term transactions due to increasing regulatory uncertainty and continued deterioration of creditworthy counterparties; (3) IDACORP failed to account for the fact that IPC may not recover from the lingering effects of the prior year's regional drought and (4) as a result of the foregoing, defendants lacked a reasonable basis for their positive statements about IDACORP and their earnings projections. The Powell complaint also alleged that the defendants' conduct artificially inflated the price of IDACORP's common stock. The actions seek an unspecified amount of damages, as well as other forms of relief. By order dated August 31, 2004, the court consolidated the Powell and Shorthouse cases for pretrial purposes, and ordered the plaintiffs to file a consolidated complaint within 60 days. On November 1, 2004, IDACORP and the directors and officers named above were served with a purported consolidated complaint captioned Powell, et al. v. IDACORP, Inc., et al., which was filed in the U.S. District Court for the District of Idaho.

The new complaint alleged that during the class period IDACORP and/or certain of its officers and/or directors made materially false and misleading statements or omissions about its business operations, and specifically the IE financial outlook, in violation of Rule 10b-5, thereby causing investors to purchase IDACORP's common stock at artificially inflated prices. The new complaint alleged that IDACORP failed to disclose and misrepresented the following material adverse facts which were known to it or recklessly disregarded by it: (1) IDACORP falsely inflated the value of energy contracts held by IE in order to report higher revenues and profits; (2) IDACORP permitted IPC to inappropriately grant native load priority for certain energy transactions to IE; (3) IDACORP failed to file 13 ancillary service agreements involving the sale of power for resale in interstate commerce that it was required to file under Section 205 of the Federal Power Act; (4) IDACORP failed to file 1,182 contracts that IPC assigned to IE for the sale of power for resale in interstate commerce that IPC was required to file under Section 203 of the Federal Power Act; (5) IDACORP failed to ensure that IE provided appropriate compensation from IE to IPC for certain affiliated energy transactions; and (6) IDACORP permitted inappropriate sharing of certain energy pricing and transmission information between IPC and IE. These activities allegedly allowed IE to maintain a false perception of continued growth that inflated its earnings. In addition, the new complaint alleges that those earnings press releases, earnings release conference calls, analyst reports and revised earnings guidance releases issued during the class period were false and misleading. The action seeks an unspecified amount of damages, as well as other forms of relief. IDACORP and the other defendants filed a consolidated motion to dismiss on February 9, 2005, and the plaintiffs filed their opposition to the consolidated motion to dismiss on March 28, 2005. IDACORP and the other defendants filed their response to the plaintiff's opposition on April 29, 2005 and oral argument on the motion was held on May 19, 2005.

On September 14, 2005, Magistrate Judge Mikel H. Williams of the U.S. District Court for the District of Idaho issued a Report and Recommendation that the defendants' motion to dismiss be granted and that the case be dismissed. The Magistrate Judge determined that the plaintiffs did not satisfactorily plead loss causation (i.e., a causal connection between the alleged material misrepresentation and the loss) in conformance with the standards set forth in the recent United States Supreme Court decision of Dura Pharmaceuticals, Inc. v. Broudo, 544 U.S. 336, 125 S. Ct. 1627 (2005). The Magistrate Judge also concluded that it would be futile to afford the plaintiffs an opportunity to file an amended complaint because it did not appear that they could cure the deficiencies in their pleadings. Each party filed objections to different parts of the Magistrate Judge's Report and Recommendation.

On March 29, 2006, the U.S. District Court for the District of Idaho (Judge Edward J. Lodge) issued an Order in this case (Powell v. IDACORP) adopting the Report and Recommendation of Magistrate Judge Williams issued on September 14, 2005, granting the defendants' (IDACORP and certain of its officers and directors) motion to dismiss because plaintiffs failed to satisfy the pleading requirements for loss causation. However, Judge Lodge modified the Report and Recommendation and ruled that plaintiffs had until May 1, 2006, to file an amended complaint only as to the loss causation element. On May 1, 2006, the plaintiffs filed an amended complaint. The defendants filed a motion to dismiss the amended complaint on June 16, 2006, asserting that the amended complaint still failed to satisfy the pleading requirements for loss causation. Briefing on this most recent motion to dismiss was completed on August 28, 2006 and oral argument was held on February 26, 2007.

IDACORP and the other defendants intend to defend themselves vigorously against the allegations. IDACORP cannot, however, predict the outcome of these matters.

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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 sitting by designation in the U.S. District Court for the Southern District of California. The companies' filed a motion to dismiss the complaint which the court granted on February 11, 2005. Wah Chang appealed the dismissal to the U.S. Court of Appeals for 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 and oral argument is scheduled for April 10, 2007. The companies intend 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 sitting by designation in the U.S. District Court for the Southern District of California. The companies filed a motion to dismiss the complaint which the court granted on February 11, 2005. The City of Tacoma appealed to the U.S. Court of Appeals for 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 and oral argument is scheduled for April 10, 2007. The companies intend 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: IE and IPC are involved in a number of FERC proceedings arising out of the western energy situation in California and claims that dysfunctions in the organized California markets contributed to or caused unjust and unreasonable prices in Pacific Northwest spot markets, and may have been the result of manipulations of gas or electric power markets. They include proceedings involving:

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(1) California Power Exchange Chargeback: the chargeback provisions of the California Power Exchange (CalPX) participation agreement triggered when a participant defaulted on a payment to the CalPX. Upon such a default, other participants were required to pay their allocated share of the default amount to the CalPX. This provision was first triggered by the Southern California Edison default and later by the Pacific Gas and Electric Company default. The FERC has ordered the CalPX to hold the chargeback funds and that such funds may be used to make-up individual seller shortfalls in their CalPX account at the conclusion of the California Refund proceeding. Based upon the Offer of Settlement filed with the FERC on February 17, 2006 between the California Parties and IE and IPC discussed below in the California refund proceeding, the California Parties supported a motion filed by IE and IPC with the FERC seeking an Order Directing Return of Chargeback Amounts then held by the CalPX totaling $2.27 million. In the May 22, 2006 order approving the Settlement, the FERC granted the IE and IPC motion for return of chargeback funds held by the CalPX. On June 1, 2006, IE received approximately $2.5 million from the CalPX representing the return of $2.27 million in chargeback funds plus interest.

(2) California Refund: proceeding which originated with an effort by the State of California to obtain refunds for a portion of the spot market sales from sellers of electricity into California from October 2, 2000 through June 20, 2001. California is claiming that the sales prices were not just and reasonable and were not in compliance with the Federal Power Act. The FERC issued an order on refund liability on March 26, 2003 on which multiple parties, including IE, sought rehearing. On October 16, 2003, the FERC denied the requests for rehearing and required the California Independent System Operator (Cal ISO) to make a compliance filing regarding refund amounts within five months, which has been delayed on a number of occasions and has not yet been filed with the FERC. On May 12, 2004, the FERC issued an order clarifying its earlier refund orders and denying a request by certain parties to present as evidence an earlier settlement between the California Public Utilities Commission and El Paso related to manipulation of gas pipeline capacity claiming that the settlement dollars California is receiving from El Paso ($1.69 billion) are duplicative of the FERC order changing the gas component of its refund methodology. The FERC denied requests for rehearing on November 23, 2004. On December 2, 2003, IE and others petitioned the United States Court of Appeals for the Ninth Circuit for review of the FERC's orders on California refunds. As additional FERC orders have been issued, further petitions for review have been filed, including by IE, and have been consolidated with the appeals already pending before the Ninth Circuit. On September 21, 2004, the Ninth Circuit convened the first of its case management proceedings, a procedure reserved to help organize complex cases. On October 22, 2004, the Ninth Circuit severed several issues related to the FERC's refund jurisdiction, established a schedule for briefing and held oral argument on April 12 and 13, 2005. On September 6, 2005, the Ninth Circuit issued a decision in one of the severed cases concluding that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. On August 2, 2006, the Ninth Circuit issued its decision on a second severed case ruling that all transactions that occurred within or as a result of the CalPX and the Cal ISO were the proper subject of the refund proceeding; refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000 but required FERC to reconsider based upon claims that some market participants had violated governing tariff obligations (the California Parties are seeking a refund effective date of May 1, 2000); and effectively expanded the scope of the refund proceeding to transactions within the CalPX and Cal ISO markets outside the 24-hour spot market and energy exchange transactions. On August 8, 2005 the FERC issued an order establishing a framework for those sellers wanting to make a cost filing to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. The companies along with others made a cost filing on September 14, 2005, the California entities commented on October 11, 2005, and IPC and IE replied to those comments on October 17, 2005. The California entities filed supplemental comments on October 24, 2005 and the companies filed supplemental reply comments on October 27, 2005.

In December 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 of a ruling on the cost filing 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 Company, 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. Other parties had until March 9, 2006 to elect to become an additional settling party. Final comments on the settlement were due to be filed by March 20, 2006. A number of other parties, representing substantially less than the majority of potential refund claims, chose to opt out of the settlement.

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On March 27, 2006, the FERC issued an order rejecting the IE/IPC cost filing and on April 26, 2006, IE and IPC sought rehearing of the rejection. By order of April 27, 2006, the FERC tolled the time for what otherwise would have been required by statute to make a decision on the request for rehearing.
On May 12, 2006, the FERC issued an order determining the method that should be used to allocate amounts approved in cost filings, approving the methodology that IE and IPC and others had advocated prior to the time IE and IPC entered into the February 17, 2006 settlement - allocating cost offsets to buyers in proportion to the net refunds they are owed through the Cal ISO and CalPX markets. On June 12, 2006, the California Parties requested rehearing, urging the FERC to allocate the cost offsets to all purchasers from the Cal ISO and CalPX markets and not just to that limited subset of purchasers who are net refund recipients. On July 12, 2006, the FERC tolled the time to act on the request for rehearing and has not issued orders on rehearing since that time. IDACORP and IPC are unable to predict how or when the FERC might rule on the request for rehearing.

After consideration of comments, the FERC approved the February 17, 2006 Offer of Settlement on May 22, 2006. Under the terms of the Settlement, IE and IPC assigned $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 that 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. Any excess funds remaining at the end of the case are to be returned to IPC and IE. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the settlement. On July 10, 2006, IPC and IE and the California Parties filed a response to Port of Seattle's request for rehearing. On October 5, 2006, the FERC issued an order denying the Port of Seattle's request for rehearing. On October 24, 2006, the Port of Seattle petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC orders approving the settlement. The Ninth Circuit consolidated that review petition with the large number of review petitions already consolidated before it. On January 23, 2007, IPC and IE filed a motion to sever the Port of Seattle's petition for review from the bulk of cases pending in the Ninth Circuit with which it had been consolidated. IPC and IE also filed a motion to dismiss the Port of Seattle's petition for review. The Port of Seattle filed their answers in opposition to the motion to sever and the motion to dismiss on February 1, 2007, and IPC and IE replied on February 12, 2007. IDACORP and IPC are not able to predict when or how the Ninth Circuit might rule on the motions.

On December 31, 2005, with respect to the CalPX chargeback and the California Refund proceedings discussed above, the CalPX and the Cal ISO owed $14 million and $30 million, respectively, for energy sales made to them by IPC in November and December 2000. In the fourth quarter of 2005, IE reduced by $9.5 million to $32 million its reserve against these receivables. This reserve was calculated taking into account the uncertainty of collection, given the California energy situation. Following payment of the $10.25 million to IE and IPC in June 2006, IE further reduced the reserve by $24.9 million to $7.1 million. This reserve was calculated taking into account several unresolved issues in the California refund proceeding. Based on the reserve recorded as of December 31, 2006, IDACORP believes that the future collectibility of these receivables or any potential refunds ordered by the FERC would not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

(3) Pacific Northwest Refund: proceedings wherein it was argued that the spot market in the Pacific Northwest was affected by the dysfunction in the California market, warranting refunds. The FERC rejected this claim on June 25, 2003, and denied rehearing on November 11, 2003 and February 9, 2004. The FERC orders were appealed to the Ninth Circuit. Oral argument was held on January 8, 2007. The companies intend 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.

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(4) Market Manipulation: two FERC show cause orders which resulted from a ruling of the Ninth Circuit that the FERC permit the California parties in the California refund proceeding to submit materials to the FERC demonstrating market manipulation by various sellers of electricity into California. On June 25, 2003, the FERC ordered a large number of parties including IPC to show cause why certain trading practices did not constitute gaming ("gaming") or anomalous market behavior ("partnership") in violation of the Cal ISO and CalPX Tariffs. On October 16, 2003, IPC reached agreement with the FERC Staff on the show cause orders. The "gaming" settlement was approved by the FERC on March 3, 2004. The FERC approved the motion to dismiss the "partnership" proceeding on January 23, 2004. Although the orders establishing the scope of the show cause proceedings are presently the subject of review petitions in the Ninth Circuit, the order dismissing IPC from the "partnership" proceedings was not the subject of rehearing requests. Originally, eight parties requested rehearing of the FERC's March 3, 2004 order approving the "gaming" settlement. The settlement between the California Parties and IE and IPC discussed above in the California refund proceeding approved by the FERC on May 22, 2006, results in the California Parties and other settling parties withdrawing their requests for rehearing of IPC's and IE's settlement with the FERC Staff regarding allegations of "gaming". On October 11, 2006, the FERC issued an order denying rehearing of its earlier approval of the "gaming" allegations, thereby effectively terminating the FERC investigations as to IPC and IE regarding bidding behavior, physical withholding of power and "gaming" without finding of wrongdoing. On October 24, 2006, the Port of Seattle appealed the FERC order to the U.S. Court of Appeals for the Ninth Circuit.

In addition to the two show cause orders, on June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale markets for the time period May 1, 2000 through October 1, 2000 to review evidence of economic withholding of generation. IPC, along with over 60 other market participants, responded to the FERC data requests and the FERC terminated its investigations as to IPC on May 12, 2004. Numerous parties have appealed the FERC's termination of this investigation as to IPC and over 30 other market participants.

Sierra Club Lawsuit- Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in federal district court in Cheyenne, Wyoming for alleged violations of the Clean Air Act's opacity standards (alleged violations of air pollution permit emission limits) at the Jim Bridger coal fired plant ("Plant") in Sweetwater County, Wyoming. IPC has a one-third ownership interest in the Plant. PacifiCorp owns a two-thirds interest and is the operator of the Plant. The complaint alleges thousands of violations and seeks declaratory and injunctive relief and civil penalties of $32,500 per day per violation as well as costs of litigation, including reasonable attorney fees. IPC believes there are a number of defenses to the claims and intends to vigorously defend its interest in this matter, but is unable to predict its outcome and is unable to estimate the impact this may have on its consolidated financial positions, results of operations or cash flows.

These matters are also discussed in Note 7 to IDACORP's and IPC's Consolidated Financial Statements.

Other Legal Proceedings: IDACORP, IPC and/or IE are involved in lawsuits and legal proceedings in addition to those discussed above and in Note 7 to IDACORP's and IPC's Consolidated Financial Statements. The companies believe they have meritorious defenses to all lawsuits and legal proceedings where they have been named as defendants. Resolution of any of these matters will take time, and the companies cannot predict the outcome of any of these proceedings. The companies believe that their reserves are adequate for these matters.

Other Matters: The Bennett Mountain combustion turbine suffered a mechanical failure on July 11, 2006. IPC's investigation has revealed that during construction a bolt was negligently installed by a third party. The bolt came loose, causing extensive mechanical damage. The plant was down from July 12, 2006 through September 6, 2006. Total repair costs were approximately $16 million. IPC anticipates that insurance proceeds and/or recovery from the party or parties responsible for the failure will result in substantial reimbursement of these costs. Involved insurers and construction contractors have been notified and cost recovery processes are underway. At this time, no legal proceedings have commenced. IPC is vigorously pursuing its interest in this matter.

Environmental Issues

Idaho Water Management Issues

Idaho experienced six consecutive years of below normal precipitation and stream flows from 2000 through 2005. These conditions exacerbated a developing water shortage in the state, which is manifested by a number of water issues including declining Snake River base flows and declining levels in the Eastern Snake Plain Aquifer, a large underground aquifer that has been estimated to hold between 200 - 300 maf of water. These issues are of interest to IPC because of their potential impacts on generation at IPC's hydroelectric projects. With respect to base flows, observed records suggest that the base flows in the Snake River, particularly between IPC's Twin Falls and Swan Falls projects, have been in decline for several decades. The yearly average flow measured below Swan Falls declined at an average rate of 43 cubic feet per second (cfs) per year during the period 1961-2003, and between Twin Falls and Lower Salmon Falls, which significantly contribute to base flow, declined at a rate of approximately 27 cfs per year over the same period. Low flow in the Snake River near Hagerman, Idaho was observed during 2005, where several river gauges in that area recorded the lowest January - March Snake River flows since the early 1960's.

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As a result of these declines in river flows, in 2003 several surface water users filed delivery calls with the Idaho Department of Water Resources (IDWR), demanding that it manage ground water withdrawals pursuant to the prior appropriation doctrine of "first in time is first in right" and curtail junior ground water rights that are depleting the aquifer and affecting flows to senior surface water rights. These delivery calls have resulted in several administrative actions before the IDWR and judicial actions before the State District Court in Ada and Gooding counties in Idaho challenging the constitutionality of state regulations used by the IDWR to conjunctively administer ground and surface water rights. One such action, filed in January 2005, involves seven surface water irrigation entities from above Milner Dam that submitted a delivery call letter to the Director of the IDWR requesting that the Director administer and deliver their senior natural flow and storage water rights pursuant to Idaho law. The irrigation entities contend that existing data reflects that senior surface water rights above Milner Dam have been reduced by approximately 600,000 acre-feet, a 30 percent reduction, over the past six years, due in part to junior groundwater pumping from the Eastern Snake Plain Aquifer, and that these reductions have resulted in cumulative shortages in natural flow and storage water accrual in American Falls Reservoir, a U.S. Bureau of Reclamation reservoir that supplies a portion of their senior water rights. The Idaho Ground Water Appropriators, Inc., an Idaho non-profit corporation organized to promote and represent the interests of groundwater users, and the U.S. Bureau of Reclamation, the owner of American Falls Reservoir, petitioned to intervene in the delivery call action. Both petitions were granted.

Since IPC holds water rights that are dependent on the Snake River, spring flows and the overall condition of the Eastern Snake Plain Aquifer, IPC continues to participate in actions, as necessary, to protect its water rights. One such action relates to the constitutionality of the Conjunctive Management Rules (CMR) that were developed by the IDWR to administer connected ground and surface water rights. In August 2005, the surface water irrigation entities that initiated the delivery call filed an action against the IDWR in the state district court in Gooding County, Idaho for a declaratory judgment regarding the validity and constitutionality of the CMR. IPC intervened in the action as a plaintiff/intervenor in alignment with the surface water users. The Idaho Ground Water Appropriators intervened as a defendant. In October 2005, the plaintiffs in the case filed a motion for summary judgment, contending that the CMR were unconstitutional and violated the doctrine of prior appropriation as applied in Idaho. After briefing and argument, on June 2, 2006, the district court issued a memorandum decision granting summary judgment to the plaintiffs and holding that the CMR are unconstitutional because the rules failed to protect senior water rights from injury by junior water right diversions. On July 11, 2006, the IDWR appealed the court's order to the Idaho Supreme Court and subsequently filed a motion with the district court asking the court to stay the effect of its order until the conclusion of the appeal. IPC is participating in the appeal. On September 27, 2006, the Idaho Supreme Court entered an order denying the stay and expediting the appeal. Oral argument was held on December 8, 2006 and the parties are currently waiting for the court's decision.

IPC, together with other interested water users and state interests, also continues to explore and encourage the development of a long-term management plan that will protect the aquifer and the river from further depletion. One management option being explored is aquifer recharge, or using surface water supplies to increase ground water supplies by allowing the water to percolate into the aquifer in porous locations. Under certain circumstances aquifer recharge may impact senior water rights, including water rights held by IPC for hydropower purposes, and therefore conflict with state law. For that reason, IPC continues to participate in the processes that are considering solutions, such as aquifer recharge, to the conflict between ground and surface water interests in an effort to protect its existing hydroelectric generation water rights.

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In February 2006, at the request of senior surface water interests, IPC entered into discussions with the State of Idaho, through the Office of the Governor, and senior surface water interests to explore opportunities for engaging in some limited aquifer recharge in 2006, provided any adverse impact to IPC's hydropower generation and its customers was adequately addressed. These discussions led to a proposal to implement a recharge pilot program in 2006. However, before that proposal could be finalized, on March 17, 2006, the House of Representatives of the State of Idaho passed House Bill 800, which proposed to repeal certain provisions of the Idaho Code that governed the use of natural water flow to recharge the Eastern Snake Plain Aquifer and would have subordinated certain hydropower water rights held by IPC to aquifer recharge. The introduction of House Bill 800 effectively concluded the discussions between IPC, senior surface water interests and the Governor's Office to implement a pilot recharge project.
IPC strongly opposed House Bill 800 because, if it had become law, IPC's hydroelectric generation could have been reduced and IPC would have had to rely on more expensive generation or purchased power to meet customers' needs. This would have resulted in higher costs to IPC's customers. On March 30, 2006, the Senate defeated House Bill 800 by a vote of 21 to 14.

At the conclusion of the legislative session, the Senate passed Senate Concurrent Resolution 136 directing the Idaho Water Resource Board (IWRB) to develop a comprehensive aquifer management plan for the Eastern Snake Plain Aquifer (ESPA) and to receive public input regarding the goals, objectives, and methods of management for the ESPA from affected water right holders, cities, counties, the general public and state and federal agencies. The IWRB initiated a public process for the development of an aquifer management plan in June 2006. IPC is participating in that process. The IWRB is expected to report to the Idaho Legislature in 2007 on the progress of the planning effort.

On April 11, 2006, IPC and the State of Idaho entered into a stipulation agreement regarding two water right permits. The permits allow for limited aquifer recharge and are held by the IWRB. The two water right permits were issued in the early 1980's, prior to the 1984 Swan Falls Agreement. IPC entered into the Swan Falls Agreement with the Governor and Attorney General of Idaho in October 1984 to resolve litigation relating to IPC's water rights at the Swan Falls project. In the early 1980's, IPC filed an action identifying approximately 7,500 water licenses and permits that had the potential to adversely impact IPC's hydropower water rights at the Swan Falls project. The Swan Falls Agreement resolved that litigation. One provision of the Swan Falls Agreement provided that the action against the 7,500 water licenses and permits would be dismissed with prejudice and that IPC's hydropower water rights on the middle Snake River would be subordinate to those water rights dismissed. In the stipulation, IPC and the state recognized that the two water right permits referred to above were named in the action brought by IPC and were subject to the Swan Falls Agreement and that IPC's water rights are therefore subordinate to these water right permits. IPC cannot determine the financial impact of the stipulation upon IPC and its customers until such time, if ever, that recharge programs under the two water permits are established, but IPC believes that the potential maximum impact in a median water year may be approximately $30 million.

The stipulation also provided that, in the event that there are disagreements between the parties to the Swan Falls Agreement as to the interpretation or application of the Agreement, the parties will attempt to resolve those disagreements through informal discussions and negotiations and that in the event that the parties are unable to resolve such disagreements, either party may file a declaratory action with a court of appropriate jurisdiction to have the disagreement resolved. On December 22, 2006, the State of Idaho, through the Attorney General's office, filed a notice of claim of ownership with the IDWR for a portion of the water rights held by IPC that are subject to the Swan Falls Agreement. Subsequently, IDWR filed a Director's Report with the Snake River Basin Adjudication (SRBA) court incorporating the State's claim of ownership and recommending that the SRBA court decree IPC's water rights in a manner consistent with the State's claim. IPC disputes the State's claim of ownership and intends to file an objection to the IDWR recommendation. Objections must be filed with the SRBA court by April 2008. IPC is currently reviewing the State's ownership claim to determine the potential effect upon IPC's water rights and whether it may affect power generation.

Air Quality Issues

IPC owns two natural gas combustion turbine power plants and co-owns three coal-fired power plants that are subject to air quality regulation. The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. The coal-fired plants are: Jim Bridger (33 percent interest) located in Wyoming; Boardman (ten percent interest) located in Oregon; and North Valmy (50 percent interest) located in Nevada.

Clean Air: The Environmental Protection Agency (EPA) issued sulfur dioxide (SO_2) allowances, as defined in the Clean Air Act amendments of 1990, based on coal consumption during established baseline years. IPC currently has more than a sufficient amount of SO_2 allowances to provide compliance for emissions attributable to IPC at all three of its jointly-owned coal-fired facilities and both of its natural gas-fired facilities.

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In July 1997, the EPA announced the revised National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. The EPA has promulgated regulations designating areas of the country for attainment/non-attainment with these standards and IPC's thermal plants are currently located in areas designated as attainment for both standards. On September 21, 2006, the EPA adopted a final rule which lowered the 24-hour $PM_{2.5}$ (Particulate Matter less than 2.5 microns) standard to 35 micrograms per cubic meter. States must make their initial recommendations to the EPA on attainment and non-attainment designations by December 2007. However, final designations need not be signed until December 2009 and do not take effect until April 2010. IPC continues to monitor the status of efforts to implement the new $PM_{2.5}$ standard and the designation of areas around its thermal plants. Although the impacts of the NAAQS for ozone and particulate matter standards on IPC's thermal operations are not known at this time, the future costs of compliance with these regulations could be substantial and will be dependent on if and how the programs are ultimately implemented.

The Clean Air Interstate Rule (CAIR) will cap emissions of SO_2 and nitrogen oxides in 28 eastern states and the District of Columbia. The CAIR does not impose any restrictions on emissions from any IPC facilities and, therefore, IPC does not foresee any adverse effects upon its operations as a result of CAIR.

Clean Air Mercury Rule: The Clean Air Mercury Rule (CAMR) will limit mercury emissions from new and existing coal-fired power plants and creates a market-based cap-and-trade program that will permanently cap utility mercury emissions in two phases (2010 - 2017, and 2018 and beyond). Mercury emission allocations have been set at the state level, but the states are currently working to allocate the allowances to individual power plants. States had until November 17, 2006, to submit to the EPA mercury plans establishing mercury emission standards and allowances for the power plants within their jurisdictions. Mercury continuous emission monitoring systems (CEMS) are required to be installed and operational on each coal-fired unit by January 1, 2009. IPC is actively monitoring developments on state mercury plans in Idaho, Wyoming, Nevada, and Oregon.

On October 10, 2006, the Wyoming Environmental Quality Commission approved the Wyoming Department of Environmental Quality's (WDEQ) recommended Wyoming regulation to implement CAMR. This rule will allocate mercury allowances to each plant based on heat-input and hold back 10 percent of the allocated allowances for new sources. This rule will also allow plants to participate in the national cap-and-trade program. Mercury CEMS are planned to be installed at the Jim Bridger plant in 2007 and 2008 at an estimated cost of $0.7 million (IPC share). Until the mercury CEMS are installed and operational, the amount of mercury emissions is not definitively known. It is not possible at this time to determine the effect of the allowance allocation rule on future operations and costs at the plant.

On December 15, 2006, the Oregon Environmental Quality Commission (OEQC) adopted the Oregon Department of Environmental Quality proposed utility mercury rule. IPC estimates that capital expenditures for mercury controls at Boardman will be $9.2 million (IPC's share) with an annual incremental operations and maintenance cost of up to $0.8 million (IPC's share). The mercury rule will provide a limited number of mercury allowances to Boardman that may be used for trading.

The Nevada Department of Environmental Protection has adopted a state CAMR that will provide mercury allowances to each plant based on actual emissions until 2018, at which time the allowance allocations will be reduced to meet the federal cap. To meet the reduced allocations in the year 2018, mercury controls are expected to be installed. Mercury CEMS are planned to be installed at the North Valmy plant in 2007 and 2008 at an estimated cost of $0.4 million (IPC's share).

IPC anticipates that the CAMR will require additional emission controls and expenses at all of its jointly-owned coal-fired facilities, although impacts on future plant operations, operating costs and generating capacity are not known at this time.

The Idaho Board of Environmental Quality has adopted two new rules: a proposed rule to opt out of the federal mercury cap-and-trade program; and a proposed rule to prohibit the construction and operation of a coal-fired power plant in Idaho. The rules will be sent to the Idaho Legislature for review and approval during its 2007 session.

Regional Haze - Best Available Retrofit Technology: In accordance with new federal regional haze rules, the WDEQ and ODEQ are conducting an assessment of emission sources pursuant to a Regional Haze Best Available Retrofit Technology (RH BART) process. Coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger and Boardman plants. The two units at the North Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule.

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On December 5, 2006, the WDEQ adopted regulations to comply with the federal RH BART standard and the Jim Bridger plant submitted required reports to the WDEQ on January 12, 2007. The WDEQ will perform a review, including a comment period, and revise the State Implementation Plan, which is to be provided to the EPA by March 2008. During the acquisition of PacifiCorp by MidAmerican Energy Holdings Company (MEHC), MEHC committed to install additional pollution control equipment at most of PacifiCorp's facilities. This commitment includes SO_3 injection, additional low NOx burners and scrubber upgrades at the Jim Bridger plant. Over the next three years, upgrade expenditures are currently estimated at $9 million (IPC's share), with total project costs currently estimated at $15 million (IPC's share).

In Oregon, a demonstration analysis for identified haze sources, utilizing modeling techniques, began in 2006 and is currently in progress. Those sources which are determined to cause or contribute to visibility impairment at protected areas will be subject to an RH BART determination. In January 2006, IPC volunteered to participate in an ODEQ pilot project that will analyze information about air emissions from the Boardman plant to determine the effect on visibility in the region, particularly in wilderness and scenic areas. The pilot project is expected to be completed by the end of the second quarter of 2007.

Greenhouse Gases: IPC continues to monitor and evaluate the possible adoption of national, regional, or state greenhouse gas (GHG) requirements. Several GHG bills were introduced in the U.S. Senate and House of Representatives during 2006 and 2007. National, regional or state GHG requirements, if enacted and applicable, could result in significant costs to IPC to comply with restrictions on carbon dioxide or other GHG emissions.

Endangered Species

In December 1992, the U.S. Fish and Wildlife Service listed several species of fish and five species of snails living within IPC's operating area as threatened or endangered species under the Endangered Species Act. IPC continues to review and analyze the effect such designation has on its operations and is cooperating with governmental agencies to resolve issues related to these species.

On December 21, 2006, IPC and Idaho Governor James Risch submitted a petition to the U.S. Fish and Wildlife Service to de-list the threatened Bliss Rapids snail. The petition was supported with data collected by IPC over the past 14 years. The snail, which lives throughout the middle Snake River, springs, and tributaries between Niagara Springs and King Hill, was listed as threatened under the Endangered Species Act in 1992. The Fish and Wildlife Service has one year to decide if de-listing is warranted. With this filing, three of the five snail species that are found in the middle Snake River and were originally listed as threatened or endangered species in 1992 are now being considered for removal from the list.

Pursuant to FERC License 1971, IPC owns and finances the operation of anadromous fish hatcheries and related facilities to mitigate the effects of its hydroelectric dams on fish populations. In connection with its fish facilities, IPC sponsors ongoing programs for the control of fish disease, improvement of fish production, and evaluation of hatchery performance. IPC's anadromous fish facilities at Hells Canyon, Oxbow, Rapid River, Pahsimeroi and Niagara Springs continue to be operated by the Idaho Department of Fish and Game. At December 31, 2006, the investment in these facilities was $15 million and the annual cost of operation was $3 million.

REGULATORY MATTERS:

General Rate Case

Idaho: On May 12, 2006, the IPUC issued an order approving a settlement of IPC's general rate case filed in October 2005. The order approves an average increase of 3.2 percent in base rates, or $18 million in revenues, effective June 1, 2006.

IPC's original filing had asked for an annual increase to its Idaho retail base rates of $44 million, a 7.8 percent average increase. The rate case filing was made with six months of actual operating expenses and six months of projected expenses. The actual increase in rates was lower than the requested amount due to three factors: (1) 2005 actual expenses 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.

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IPC expects to file a new general rate case with the IPUC in 2007.
Oregon: On September 21, 2004, IPC filed an application with the OPUC to increase general rates an average of 17.5 percent or approximately $4.4 million annually. A partial settlement resolved most issues in a manner consistent with the results of the corresponding Idaho general rate case. The most significant issue in this proceeding was the appropriate quantification of net power supply expenses for purposes of setting rates. The OPUC Staff proposed that net power supply expenses for IPC be set at a negative number - meaning that IPC should be able to sell enough surplus energy to pay for all fuel and purchased power expenses and still have revenue left over to offset other costs. The bulk of IPC's rebuttal was directed at this position. A hearing was conducted on May 23, 2005. The OPUC issued its order in July 2005 authorizing an increase of $0.6 million in annual revenues for an average of 2.37 percent. The OPUC adopted the OPUC Staff's argument for the negative net power supply costs, thus reducing IPC's initial rate request of $4.4 million by $2.4 million with this one adjustment.

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. Following a full review of the matter, the court denied IPC's reversal request on August 29, 2006. IPC did not appeal the decision.

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

		2006		2005
Idaho PCA current year:				
Deferral for the 2006-2007 rate year	$	-	$	3,684
Accrual for the 2007-2008 rate year*		(3,484)		-
Idaho PCA true-up awaiting recovery:				
Authorized May 2005		-		28,567
Authorized May 2006		(11,689)		-
Oregon deferral:				
2001 costs		6,670		8,411
2005 costs		2,889		2,880
Total (accrual) deferral	$	(5,614)	$	43,542

*Includes $69 million of emission allowance sales to be credited to the customers during the 2007-2008 PCA 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 portion, is then included in the calculation of the next year's PCA.

The true-up of the true-up portion of the PCA provides a tracking of the collection or the refund of true-up amounts. Each month, the collection or the refund of the true-up amount is quantified based upon the true-up portion of the PCA rate and the consumption of energy by customers. At the end of the PCA year, the total collection or refund is compared to the previously determined amount to be collected or refunded. Any difference between authorized amounts and amounts actually collected or refunded are then reflected in the following PCA year, which becomes the true-up of the true-up. Over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized.

On May 25, 2006, the IPUC approved IPC's 2006-2007 PCA filing with an effective date of June 1, 2006. The filing reduced the PCA component of customers' rates from the existing level, which was recovering $76.7 million above then-existing base rates, to a level that is $46.8 million below those base rates, a decrease of approximately $123.5 million.

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On June 1, 2005, IPC implemented the 2005-2006 PCA, which held the PCA component of customers' rates at the existing level recovering $71 million above base rates. By IPUC order, the PCA included $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. The PCA deferred recovery of approximately $28 million of power supply costs, or 4.75 percent, for one year to help mitigate the impacts of other rate increases. The $28 million was included in the 2006-2007 PCA filing, and IPC earned a two percent carrying charge on the balance.

Idaho Load Growth Adjustment Rate (LGAR): In April 2006 IPC filed a petition with the IPUC requesting modification of one component of its PCA referred to as the Load Growth Adjustment Rate. The LGAR subtracts the cost of serving new Idaho retail customers from the power supply costs IPC is allowed to include in its PCA.

The LGAR was set at $16.84 per megawatt-hour when the PCA began in 1993. This amount was established as the projected marginal cost of serving each new customer and is subtracted from each year's PCA expense. In its April 2006 petition, IPC requested using the embedded cost of serving the new load rather than the projected marginal cost and to lower the rate to $6.81 per megawatt-hour. The IPUC Staff recommended against changing to the embedded cost approach; IPUC Staff also recommended increasing the rate to $40.87 per megawatt hour.

On January 9, 2007, the IPUC issued its final order in this matter. The IPUC maintained the marginal cost methodology and set the new LGAR at $29.41 per megawatt-hour. The new rate becomes effective on April 1, 2007 and will first affect customer rates on June 1, 2008.

The impact of the new LGAR on IPC will ultimately be determined by future load growth. Assuming an average 40 megawatt load growth, the new rate would result in approximately $10.3 million subtracted from the next PCA, a pre-tax increase of $4.4 million over the current amount. The impact of the new LGAR can be partially offset by IPC through more frequent general rate case filings with the IPUC or from less customer growth. In its order the IPUC stated that it expected IPC to update its load growth adjustment in all future general rate cases.

Oregon: On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007, in anticipation of higher than "normal" power supply expenses. In the Oregon general rate case discussed above, "normal" power supply expenses were set at a negative number (meaning that under normal water conditions IPC should be able to sell enough surplus energy to pay for all fuel and purchased power expenses and still have revenue left over to offset other costs). The forecasted system net power supply expenses included in this deferral filing were $64 million, which is $65.9 million higher than the normalized power supply expenses established in the Oregon general rate case. IPC requested authorization to defer an estimated $3.3 million, the Oregon jurisdictional share of the $65.9 million. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. The parties met on September 20, 2006, and began negotiating for a PCA mechanism for IPC's Oregon jurisdiction, and agreed to suspend discussion of the deferral application while the PCA negotiations are ongoing. The parties believe that any agreement regarding a PCA mechanism may impact resolution of IPC's deferral application. The parties met on November 27, 2006. Further workshops are planned for 2007, but have not yet been scheduled.

The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent per year. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2001. Full recovery of the 2001 deferral is not expected until 2009. A 2006-2007 deferral would have to be amortized sequentially following the full recovery of the 2001 deferral.

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On March 2, 2005, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of March 2, 2005 through February 28, 2006, in anticipation of continued low water conditions. The forecasted net power supply costs included in this filing were $169 million, of which $3 million related to the Oregon jurisdiction. IPC proposed 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. The OPUC issued Order 05-870 on July 28, 2005, approving the stipulation. On April 19, 2006, IPC filed a request for review and acknowledgement of its deferred net power supply costs for the period of March 2, 2005, through February 28, 2006. On June 14, 2006, a settlement conference was held. On December 14, 2006, IPC responded to additional data requests by the OPUC. The OPUC Staff subsequently drafted a settlement stipulation under which the parties agree that IPC appropriately deferred approximately $2.7 million during the 2005 deferral period. The stipulation also provides that, rather than amortizing the 2005 deferral into rates, IPC should offset the balance with the Oregon jurisdictional share of proceeds from the sale of SO_2 emission allowances and the benefit that IPC will receive from income taxes already paid on the sale of those allowances. When combined, these offsets exceed the 2005 deferral balance. The stipulation was filed with the OPUC on January 31, 2007. A final order is expected from the OPUC during the first quarter of 2007.

Emission Allowances

In June 2005, IPC filed applications with the IPUC and OPUC requesting blanket authorization for the sale of excess SO_2 emission allowances and an accounting order. The IPUC issued Order 29852 on August 22, 2005, authorizing the sale and interim accounting treatment. The OPUC issued Order 05-983 on September 13, 2005, stating that IPC did not need a blanket order to sell emission allowances and approved the interim accounting treatment.

In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for approximately $81.6 million (before income taxes and expenses) on the open market. After subtracting transaction fees, the total amount of sales proceeds to be allocated to the Idaho jurisdiction is approximately $76.8 million ($46.8 million net of tax, assuming a tax rate of approximately 39 percent). Through allowance year 2006, IPC has approximately 36,000 excess allowances.

Pursuant to the IPUC order, the IPUC Staff held several workshops and settlement discussions. On May 12, 2006, the IPUC approved a stipulation filed in April 2006 by IPC on behalf of several parties. The stipulation allows IPC to retain ten percent, or approximately $4.7 million after tax, of the emission allowance net proceeds as a shareholder benefit. The remaining 90 percent of the sales proceeds ($69.1 million) plus a carrying charge will be recorded as a customer benefit and included as a line-item in the PCA true-up. The carrying charge will be calculated on $42.1 million, the net-of-tax amount allocable to Idaho jurisdiction customers. This customer benefit is included in IPC's PCA calculations as a credit to the PCA true-up balance and will be reflected in PCA rates during the June 1, 2007 through May 31, 2008 PCA rate year.

As discussed above, a stipulation is currently before the OPUC which would offset SO_2 emission allowance proceeds against the 2005-2006 balance of Oregon deferred power supply cost. The stipulation allows for IPC to retain ten percent of the proceeds from emission allowance sales as a shareholder benefit.

Fixed Cost Adjustment Mechanism (FCA)

On January 27, 2006, IPC filed with the IPUC for authority to implement a rate adjustment mechanism that would adjust rates downward or upward to recover fixed costs independent from the volume of IPC's energy sales. This filing is a continuation of a 2004 case that was opened to investigate the financial disincentives to investment in energy efficiency by IPC. This true-up mechanism would be applicable only to residential and small general service customers. The first FCA rate change under this proposal would occur on June 1, 2007, coincident with IPC's PCA rate change. The accounting for the FCA will be separate from the PCA. As part of the filing, IPC proposes a three percent cap on any rate increase to be applied at the discretion of the IPUC.

On March 6, 2006, the IPUC reviewed IPC's proposal and acknowledged the intent of IPC and the IPUC Staff to initiate and engage in settlement discussions. The IPUC Staff presented an alternate view of IPC's proposal. Three workshops were held in 2006 and the parties have agreed in concept to a three-year pilot beginning at the first of the year and a stipulation was filed on December 18, 2006. The stipulation calls for the implementation of a FCA mechanism pilot program as proposed by IPC in its original application with additional conditions and provisions related to customer count and weather normalization methodology, recording of the FCA deferral amount in reports to the IPUC and detailed reporting of DSM activities. The pilot program began on January 1, 2007, and will run through 2009, with the first rate adjustment to occur on June 1, 2008, and subsequent rate adjustments to occur on June 1 of each year thereafter during the term of the pilot program. The deadline for filing written comments with respect to the stipulation and the use of modified procedure was January 31, 2007. A final order is expected from the IPUC in the first quarter of 2007.

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FERC Proceedings

Open Access Transmission Tariff (OATT): On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. The purpose of the filing was to implement formula rates for the IPC OATT in order to more adequately reflect the costs that IPC incurs in providing transmission service. In the filing IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on FERC Form 1 data. The formula rate request included a rate of return on equity of 11.25 percent. The proposed rates would have produced an annual revenue increase of approximately $13 million based on 2004 test year data. On May 31, 2006, the FERC accepted IPC's rates, effective June 1, 2006, subject to adjustment to conform to FASB 109 tax accounting requirements, which ultimately resulted in lowering the estimated annual revenues to approximately $11 million. IPC has complied with this directive and on August 28, 2006, the FERC issued an order accepting IPC's compliance filing and ordering that this new rate be used, subject to refund as discussed below. As a result, IPC has made refunds with interest for June and July amounts billed, and started billing the new rate beginning in August. The rates are being collected subject to refund pending the outcome of the FERC hearing process scheduled for May 2007 with an initial decision expected to be issued in August 2007.

On November 6, 2006, intervenors filed a motion for partial summary disposition on the issue of how a pre-1996 contract with another utility was treated in the rate calculation. On December 5, 2006, oral argument was heard by the FERC administrative law judge (ALJ). On December 15, 2006, the ALJ denied the intervenors' motion for partial summary judgment. IPC is currently preparing rebuttal testimony in this case.

FERC Order 890: On February 16, 2007, the FERC adopted a final rule amending the regulations governing its pro forma OATT. According to the FERC, the purpose of the amendment is to remedy undue discrimination by providing greater specificity in the pro forma OATT and increasing transparency in the rules applicable to planning and the use of the transmission system. The major reforms to the pro forma OATT relate to: (i) the development of more consistent methodologies and assumptions for calculating available transfer capability (ATC), (ii) more open, coordinated and transparent transmission planning, (iii) reform of the energy and generator imbalances penalties based on a tiered structure, (iv) adoption of a "conditional firm" component to long-term point-to-point service requiring transmission providers to identify system conditions, as well as reform of the redispatch service and (v) reform of the rollover rights policy. IPC, as a transmission service provider with an OATT on file with the FERC, will be required to comply with these requirements. Certain requirements provided under the final rule, such as the methodology applicable to calculating the ATC, will be determined prospectively and make it difficult at this time to determine the effect of the final rule. However, IDACORP and IPC believe that the final rule will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Cassia Wind Farm Complaint

On September 13, 2006, Cassia Gulch Wind Park, LLC and Cassia Wind Farm, LLC (collectively Cassia) filed a complaint against IPC with the IPUC requesting an IPUC declaration and determination that, as a matter of law and policy, the cost responsibility for specified transmission system upgrades to meet contingency planning conditions should not be assigned to PURPA qualifying facilities connecting to the system, but rather should be rolled into IPC's plant-in-service rate base and recovered through rates to retail and transmission customers. The estimated costs of transmission system upgrades included in this complaint that relate to connecting Cassia to IPC's system are $60 million. Cassia requested that the IPUC process its request for an order under modified procedure. The IPUC Staff contends that the policy issue raised by Cassia is one of generic consequence and has, therefore, provided copies of Cassia's complaint to both PacifiCorp and Avista and recommended that those utilities also be provided the opportunity to address the issue raised by Cassia. Initial comments were due October 27, 2006 and reply comments were due November 9, 2006. On November 17, 2006 the IPUC granted Cassia's request for oral argument on the threshold issue presented for IPUC determination by Cassia, i.e., whether a PURPA qualifying facility selling generation to a utility has a responsibility to pay the transmission upgrade costs that result from, and that would not be incurred but for, the facility's request for interconnection. Oral arguments were held November 28, 2006.

Public Utility Regulatory Policies Act of 1978

As mandated by the enactment of PURPA and the adoption of avoided cost rates by the IPUC and the OPUC, IPC has entered into contracts for the purchase of energy from a number of private developers. Under these contracts, IPC is required to purchase all of the output from the facilities located inside the IPC service territory. For projects located outside the IPC service territory, IPC is required to purchase the output that IPC has the ability to receive at the facility's requested point of delivery on the IPC system. The IPUC jurisdictional portion of the costs associated with cogeneration and small power production (CSPP) contracts are fully recovered through the PCA. For IPUC jurisdictional contracts, projects that generate up to ten average MW of energy on a monthly basis are eligible for IPUC Published Avoided Costs for up to a 20-year contract term. The Published Avoided Cost is a price established by the IPUC and the OPUC to estimate IPC's cost of developing additional generation resources. On August 4, 2005, the IPUC granted a temporary reduction in the eligible project size to 100 kW for intermittent generation resources only and ordered IPC to study the impacts of integrating this type of resource. IPC completed and filed with the IPUC a wind generation integration study report on February 6, 2007. The IPUC will evaluate the proposal, possibly including public workshops, and issue a ruling.

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For OPUC jurisdictional contracts, projects with a nameplate rating of up to ten MW of capacity are eligible for OPUC Published Avoided Costs for up to a 20-year contract term. The OPUC jurisdictional portion of the costs associated with CSPP contracts is recovered through general rate case filings. The Oregon provisions are currently being reviewed in an OPUC proceeding. If a PURPA project does not qualify for Published Avoided Costs, then IPC is required to negotiate the terms, prices and conditions with the developer of that project. These negotiations reflect the characteristics of the individual projects (i.e., operational flexibility, location and size) and the benefits to the IPC system and must be consistent with other similar energy alternatives.

Recent activities, including the extension of the Federal Production Tax Credit and the expansion of the tax credit for eligibility to solar, geothermal and other forms of generation, resolution of IPUC and OPUC PURPA-related hearings and the December 1, 2004 order by the IPUC increasing the Published Avoided Costs, create a favorable climate for PURPA project development, which may require IPC to enter into additional PURPA agreements. The requirement to enter into additional PURPA agreements may result in IPC acquiring energy at above wholesale market prices, thus increasing costs to its customers. Additionally, it is highly likely that the requirement to enter into additional PURPA agreements will add to IPC's surplus during certain times of the year. This could also increase costs to IPC's customers. As of December 31, 2006, IPC had signed agreements to purchase energy from 92 CSPP facilities with contracts ranging from one to 30 years. Of these facilities, 74 were on-line at the end of 2006; the other 18 facilities under contract are due to come on-line in 2007 and 2008. During 2006, IPC purchased 911,132 MWh from these projects at a cost of $54 million, resulting in a blended price of 5.9 cents per kilowatt hour.

Integrated Resource Plan: IPC filed its 2006 IRP with the IPUC in September 2006 and with the OPUC in October 2006. A hearing is scheduled in Oregon for June 2007. The 2006 IRP previewed IPC's load and resource situation for the next twenty years, analyzed potential supply-side and demand-side options and identified near-term and long-term actions. The two primary goals of the 2006 IRP were to: (1) identify sufficient resources to reliably serve the growing demand for energy service within IPC's service area throughout the 20-year planning period and (2) ensure that the portfolio of resources selected balances cost, risk and environmental concerns. In addition, there were four secondary goals: (1) to give equal and balanced treatment to both supply-side resources and demand-side measures, (2) to involve the public in the planning process in a meaningful way, (3) explore transmission alternatives, and (4) investigate and evaluate advanced coal technologies.

The IRP is filed every two years with both the IPUC and the OPUC. IPC's IRP process utilizes an Advisory Council consisting of representatives from the IPUC Staff, OPUC Staff, as well as representatives from customer, governmental, environmental and other interested groups and is the starting point for demonstrating prudence in IPC's resource decisions. The 20-year 2006 IRP includes the following supply-side resources:

Year	Resource	MW
2008	Wind (2005 RFP)	100
2009	Geothermal (2006 RFP)	50
2010	Combined Heat & Power	50
2012	Wind	150
2012	Transmission Capacity	225
2013	Pulverized Coal	250
2017	Regional Integrated Gasification Combined-Cycle Coal	250

2019	Transmission Capacity	60
2020	Combined Heat & Power	100
2021	Geothermal	50
2022	Geothermal	50
2023	Nuclear[1]	250

[1]The 250 MW of nuclear generation is anticipated to be acquired through a power purchase agreement for output from the Idaho National Laboratory's planned Next Generation Nuclear Project.

IPC has negotiated a Power Purchase Agreement with the successful bidder on the 100 MW wind RFP (see "Wind RFP" below). An RFP for geothermal-powered generation was released on June 2, 2006. IPC is in the process of evaluating bids and expects to identify a successful bidder during the first quarter of 2007.

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In addition to the supply-side resources identified above, the 2006 IRP also includes demand-side programs designed to reduce average energy needs by 88 MW and peak-hour needs by 187 MW. To reach these totals, existing demand-side programs will be expanded and new programs will be implemented over the 20-year planning period.

Coal-fired Resource Screening and Evaluation: In the 2006 IRP, IPC identified the need for a coal-fired resource beginning in 2013. As a result of discussions with potential resource participants, IPC and Spokane, Washington-based Avista Utilities entered into an agreement to jointly investigate possible future coal-fired resources. Under the arrangement, the utilities are studying the options for base load coal-fired generation to meet their collective IRP forecast needs. Information submittals from interested parties were received in October 2006 and IPC and Avista are currently in the process of evaluating and screening potential projects. In addition, IPC continues to evaluate other coal-fired resource opportunities, including expansion of its jointly-owned facilities.

Wind RFP (Elkhorn Wind Project): A contract with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 100 MW (nameplate) of wind generation from the Elkhorn Wind Project was signed and filed with the IPUC on December 15, 2006. IPC requested the costs associated with the Elkhorn Project be included in IPC's annual PCA. The IPUC approved the application on February 27, 2007.

Peaking Resource: On December 15, 2006, IPC received a Certificate of Convenience and Necessity to construct a turnkey Siemens Power Generation combustion turbine at the Evander Andrews Power Complex near Mountain Home, Idaho. The Certificate of Convenience and Necessity included a commitment estimate of $60 million and approval for IPC to include in rate base the prudent capital costs for construction and operating fuel costs. The turbine will provide approximately 166 MW of capacity during summer load peaks and up to 200 MW during the winter. Commercial operation is planned for spring 2008. Related transmission interconnection and line upgrades will be constructed by IPC at an estimated cost of $23 million.

IPUC Review of New PURPA Standards

The IPUC initiated a project in June 2006 to assess implementation of the Energy Policy Act of 2005. The 2005 Act amended the Public Utility Regulatory Policies Act of 1978 and added five new federal ratemaking standards for public utilities and requires state regulatory commissions to determine whether they should adopt the standards for public utilities in their jurisdictions. The five new standards relate to net metering; fuel source diversity; fossil fuel generation efficiency; time-based metering and communication; and interconnection services to customers with on-site generating facilities. In July 2006, the IPUC requested that each utility respond to questions about the proposed standards. A public workshop was held in September 2006. After evaluating the responses, the IPUC determined that, with the exception of time-based metering, all of the standards had already been adopted. The IPUC declined to adopt the time-based metering standard.

Relicensing of Hydroelectric Projects

IPC, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses last for 30 to 50 years depending on the size, complexity, and cost of the project. IPC is actively pursuing the relicensing of the Hells Canyon Complex and Swan Falls projects, a process that may continue for the next ten to fifteen years. IPC's Middle Snake River project licenses were issued in 2004.

Hells Canyon Complex: The most significant ongoing relicensing effort is the Hells Canyon Complex (HCC), which provides approximately two-thirds of IPC's hydroelectric generating capacity and 40 percent of its total generating capacity. The current license for the HCC expired at the end of July 2005. Until the new multi-year license is issued, IPC will operate the project under an annual license issued by the FERC. IPC developed the license application for the HCC through a collaborative process involving representatives of state and federal agencies and business, environmental, tribal, customer, local government and local landowner interests. The license application was filed in July 2003 and accepted by the FERC for filing in December 2003.

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On October 28, 2005, the FERC issued its Notice of Ready for Environmental Analysis, which requires the federal and state agencies, Native American tribes and other participants in the relicensing process to file preliminary comments, recommendations, terms, conditions and prescriptions under the FPA, the National Environmental Policy Act of 1969, as amended (NEPA), the Energy Policy Act and other applicable federal laws. NEPA requires that the FERC independently evaluate the environmental effects of relicensing the HCC as proposed under the final license application (the proposed action) and also consider reasonable alternatives to the proposed action. Consistent with the requirements of NEPA, the FERC Staff will prepare an environmental impact statement (EIS) for the Hells Canyon project, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The EIS will describe and evaluate the probable effects, if any, of the proposed action and the other alternatives considered. Section 241 of the Energy Policy Act modifies the existing hydroelectric relicensing process under the FPA and requires federal resource agencies with authority to impose mandatory conditions on licenses under Sections 4(e) or 18 of the FPA (conditions that the FERC must include in the license) to provide license applicants, and other parties to the licensing process, with evidentiary hearings on disputed issues of material fact related to proposed conditions. It also requires that such agencies accept more cost effective alternative conditions proposed by license applicants, or other parties, provided that the proposed alternative conditions will be no less protective of the resource or the reservation than the original condition recommended by the agency.

The federal and state agencies, Native American tribes and other interested parties filed their preliminary comments, recommendations, terms, conditions and prescriptions with the FERC on January 26, 2006. Consistent with the provisions of the FPA, IPC filed reply comments to these filings on April 11, 2006. Federal agencies with mandatory conditioning authority under sections 4(e) and 18 of the FPA also filed their preliminary terms and conditions under those sections with the FERC on January 26, 2006. The Energy Policy Act, and the interim final rules issued on November 17, 2005, to implement the Act, require IPC, within 30 days of the agency's filing of their preliminary terms and conditions with the FERC, to file requests for evidentiary hearings on disputed issues of material fact relied upon by the federal agency for support of any term or condition and also file any proposed alternative conditions. On February 27, 2006, IPC filed requests for hearing on Section 4(e) conditions filed by the Department of the Interior through the Bureau of Land Management (BLM) and the Department of Agriculture through the U. S. Forest Service (USFS). IPC also filed proposed alternative conditions with the agencies. The hearing requests related to travel and access management, law enforcement and emergency services, and recreation and land management conditions proposed by the BLM, and sediment supply and sandbar maintenance and restoration, wildlife habitat mitigation and management, noxious weed control, recreation resource management, and cultural resource management conditions filed by the USFS. Each of the agencies responded to the hearing requests and referred the requests to the hearings division within the respective agencies for assignment to an ALJ. Hearings were subsequently set before a Department of Interior ALJ for June 12, 2006, on the requests for hearing on the BLM conditions and a Department of Agriculture ALJ for June 19, 2006, on the USFS requests for hearing. While IPC was preparing for the evidentiary hearings, IPC continued to engage in discussions with the respective agencies regarding possible settlements.

Through these discussions, IPC was able to resolve the disputed issues associated with the pending hearing requests. On May 10, 2006, IPC and the USFS filed a stipulation with the Department of Agriculture ALJ, and revised preliminary terms and conditions with the FERC, resolving all issues associated with the pending USFS hearing requests except for the issues associated with the USFS condition relating to sediment supply and sandbar maintenance. These issues remained subject to hearing on June 19, 2006. On May 15, 2006, IPC and the BLM filed a stipulation with the Department of Interior ALJ and revised preliminary terms and conditions with the FERC resolving all issues associated with the pending BLM hearing requests. Through subsequent settlement discussions with the USFS, IPC resolved all disputed issues associated with the hearing request on the USFS condition relating to sediment supply and sandbar maintenance.

All of these hearing requests were resolved through stipulations between IPC and the USFS and BLM, respectively, providing for the withdrawal of IPC's requests for hearing and the filing of revised preliminary terms and conditions with the FERC with provisions that were acceptable to IPC.

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On July 28, 2006, the FERC released the draft EIS, and comments were due November 3, 2006. The draft EIS is prepared by the FERC Staff, pursuant to NEPA and applicable federal regulations, to inform the FERC Commissioners, the public, state and federal agencies and the tribes about the potential adverse and beneficial environmental effects of licensing of the project as proposed by the IPC in its license application and provide a review of other reasonable alternatives or measures that might be included in a license for the project. Based upon the draft EIS, the subsequent comments received, the license application and other material in the FERC record, the FERC Commissioners will decide whether to license the HCC and what conditions to include in the license to address project effects. However, because this is a draft EIS, containing only FERC Staff conclusions, it cannot be relied upon to accurately predict what measures will be included in the final EIS or the outcome of the relicensing process. In connection with the issuance of the draft EIS, the FERC held public meetings in Boise, Weiser and Lewiston, Idaho and Halfway, Oregon from September 7 through September 13, 2006, to take public comments on the draft EIS. Transcripts of the public meetings are filed in the FERC record. The FERC will consider these comments, in addition to the written comments received by November 3, 2006, in connection with the preparation of the final EIS.
On November 3, 2006, IPC filed comments with the FERC on the draft EIS. In large measure, the FERC Staff adopted the protection, mitigation and enhancement measures proposed by IPC in its final license application. With regard to the following issues, the FERC Staff took the following action: rejected an anadromous fish habitat restoration fund of $5-10 million per year on the basis that it has no nexus to the project; rejected operational and ramp rate restrictions below Hells Canyon Dam on the basis that sufficient information is available to determine that the aquatic community below the project is not being adversely affected by operations; rejected an 8,500 cfs navigation flow below the HCC on the basis that the alleged benefits to navigation were not worth the substantial reduction in power benefits associated with the increased flows; and accepted IPC's proposal to acquire, enhance and manage approximately 22,761 acres as appropriate on-site, in-kind mitigation for the effects of project operations on upland and riparian habitat. While IPC concurred with many of Staff's conclusions in the draft EIS, IPC did provide comments on certain portions of the draft EIS. Other parties also submitted comments on the draft EIS. IPC is now reviewing those comments to determine whether additional submittals to the FERC are necessary in response to those comments. The FERC is now in the process of reviewing the comments to the draft EIS and has advised that its preliminary schedule for the release of a final EIS is May 2007.

On August 1, 2006, the FERC requested formal consultation with the National Marine Fisheries Service (NMFS), pursuant to section 7 of the Endangered Species Act (ESA), advising the NMFS that the FERC Staff, in the draft EIS, had concluded that the licensing of the HCC was likely to adversely affect the Snake River fall Chinook salmon (threatened species), Snake River spring/summer Chinook salmon (threatened species), Snake River Sockeye salmon (endangered species) and Snake River Steelhead (threatened species), along with the critical habitat for these species. On September 7, 2006, NMFS sent a letter to the FERC advising that the draft EIS did not meet the information requirements for initiation of formal consultation under section 7 of the ESA because the draft EIS did not fully describe the action alternative that was to be subject to consultation. The NFMS advised that several processes were still underway that may affect the action alternative, including the section 10(j) process under the Federal Power Act, the outcome of the section 401 certification process under the Clean Water Act that is pending before the Departments of Environmental Quality of Idaho and Oregon, and discussions with IPC intended to craft measures to address ESA issues. For these reasons NMFS suggested that consultation should be initiated at a later time. NMFS suggested that NMFS, USFWS and IPC work cooperatively to address ESA issues as the NEPA process continues so as to assure that the licensing process is not delayed due to ESA consultation.

On August 1, 2006, the FERC requested formal consultation with the USFWS, pursuant to section 7 of the ESA, advising the USFWS that the FERC Staff, in the draft EIS, had concluded that the licensing of the HCC was likely to adversely affect the bull trout (threatened species) and its critical habitat and the bald eagle (threatened species). On August 31, 2006, the USFWS sent a letter to the FERC advising that the draft EIS did not meet the information requirements for initiation of formal consultation under section 7 of the ESA because the draft EIS did not fully describe the action alternative that was to be subject to consultation. The USFWS advised the FERC that elements relating to a new license were still under development in processes involving IPC and state and federal agencies, one such process being section 401 certification under the Clean Water Act, which is currently pending before the Departments of Environmental Quality of Idaho and Oregon. The USFWS further advised that it was also still in the process of preparing comments to the draft EIS and that the FERC had yet to complete the processes necessary under the Federal Power Act with regard to the federal agencies section 10(j) recommendations. For these reasons, the USFWS suggested that the USFWS, the NMFS, and IPC work cooperatively to address ESA issues as the NEPA process continues so as to assure that the licensing process is not delayed due to ESA consultation.

In early December 2006, in connection with scheduled meetings between the FERC and the USFWS and the NMFS on section 10(j) recommendations, the FERC, the USFWS, the NMFS and IPC met and conferred on pending ESA issues. At the conclusion of that meeting, the FERC advised that it intended to schedule a conference call in early 2007 to further discuss ESA issues. The FERC has not yet scheduled that conference call. IPC is cooperating with the USFWS, the NMFS and the FERC in an effort to address ESA concerns associated with the licensing of the HCC.

At December 31, 2006, $86 million of HCC relicensing costs were included in construction work in progress. The relicensing costs are recorded and held in construction work in progress until a new multi-year license is issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to a new license will be submitted to regulators for recovery through the ratemaking process.

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Swan Falls Project: The license for the Swan Falls hydroelectric project expires in 2010. On March 10, 2005, IPC issued a Formal Consultation Package with agencies, Native American tribes and the public regarding the relicensing of the Swan Falls project. IPC is in the process of compiling information and performing studies in preparation for filing an application for a new license with the FERC. IPC expects to file a draft license application in the fall of 2007, with the final application being filed in June 2008.

At December 31, 2006, $2 million of Swan Falls project relicensing costs were included in construction work in progress. The relicensing costs are recorded and held in construction work in progress until a new multi-year license is issued by the FERC, at which time the charges will be transferred to electric plant in service. Relicensing costs and costs related to a new license will be submitted to regulators for recovery through the ratemaking process.

Middle Snake River Projects: IPC's middle Snake River projects consist of the Bliss, Upper Salmon Falls, Lower Salmon Falls, Shoshone Falls and CJ Strike projects. On August 4, 2004, IPC received the FERC license orders for each of the middle Snake River projects. On September 2, 2004, two conservation groups, American Rivers and Idaho Rivers United, filed petitions for rehearing of the orders issuing the licenses for the middle Snake River projects. These petitions asked the FERC to vacate the licensing orders and request a determination from the USFWS that the middle Snake River projects jeopardize the listed snail species. On October 4, 2004, the FERC issued an Order Granting Rehearing for Further Consideration to provide additional time to consider the matters raised by the rehearing requests. On March 4, 2005, the FERC issued an order denying the conservation groups' rehearing request. On April 28, 2005, American Rivers and Idaho Rivers United appealed this order to the U.S. Court of Appeals for the Ninth Circuit. IPC filed a motion to intervene in the appeal and the USFWS filed a motion to be designated a respondent-intervenor. On June 15, 2005, the court granted these motions. On July 12, 2006, the Ninth Circuit issued a memorandum decision denying the conservation groups' appeal. American Rivers' and Idaho Rivers United's appeal period ended on October 10, 2006, with no action by either group. The new licenses for the middle Snake River projects are in full effect.

Shoshone Falls Expansion

On August 17, 2006, IPC filed a License Amendment Application with the FERC, which would allow IPC to upgrade the Shoshone Falls project from 12.5 MW to 62.5 MW. The FERC is currently evaluating the application and on October 10, 2006, requested additional information on 11 items. IPC has provided the additional information. In addition, on October 3, 2006, IPC filed a Water Right Application with the IDWR for rights to additional water for this potential project expansion. IPC is awaiting further action on these applications.

Regional Transmission Organizations

Over the last several years, IPC has spent funds supporting the development of Grid West, a regional transmission organization (RTO). Through the fourth quarter of 2006, IPC had loaned Grid West $1.1 million and had accumulated $2.3 million of costs in a deferred expense account, anticipating future recovery through Grid West tariffs. The deferred expenses were direct expenses incurred in the development of Grid West that were deferred based on a 2004 accounting order that IPC received from the FERC. IPC ceased funding Grid West following the dissolution of Grid West on April 11, 2006. IPC no longer expects reimbursement of either amount from Grid West.

In April 2006, IPC filed requests with the IPUC and OPUC to recover through retail rates the amounts loaned to Grid West and the deferred expenses related to the development of Grid West. On August 22, 2006, the OPUC issued an order granting IPC's recovery of the Grid West loans; however, they denied IPC's request to recover the deferred amounts. On October 24, 2006, the IPUC issued an order allowing IPC to recover the principal portion of the Grid West loans over a five-year amortization beginning January 1, 2007. The IPUC disallowed the recovery of the deferred amounts and the interest portion of the Grid West loans.

As a result of these orders, IPC recognized an impairment of $2.1 million in the fourth quarter of 2006 for the disallowance of the deferred amounts and a regulatory asset of $1.3 million for the recovery of the Grid West loan amounts.

Northern Tier Transmission Group

IPC, along with four other utilities covering all or parts of the transmission system in six western states, has formed the Northern Tier Transmission Group (NTTG). The goal of the group is to improve overall operation and expansion of the high-voltage transmission network. NTTG held its first meeting in November 2006. The group has begun three initial activities: improving generation control performance; providing improved information on available transmission capacity; and facilitating open, participatory transmission planning. Goals of the group include compliance with the new FERC Order 890.

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FERC Market-Based Rate Authority
IPC has FERC-approved market-based rate authority, which permits IPC to sell electric energy at market-based rates rather than cost-based rates. Every three years, the FERC requires a review of the conditions under which this market-based rate authority is granted to ensure that the rates charged thereunder are just and reasonable. On April 14, 2004, the FERC issued an order commencing a market power analysis of all companies with market-based rate authority, including IPC. In September 2004, IPC filed a revision of its market power analysis (based on 2003 data), which it supplemented in September and October 2004. On March 3, 2005, the FERC issued an order accepting IPC's market power analysis. IPC is required to file another market power analysis on or before March 3, 2008.

On May 2, 2005 IPC filed a "Notice of Change in Status" in accordance with FERC requirements to report the addition of Bennett Mountain Power Plant, which IPC acquired on March 31, 2005. The purpose of the filing is to explain whether, and if so, how, the addition of Bennett Mountain reflects a departure from the characteristics the FERC relied on when it authorized IPC to make sales at market-based rates.

The May 2005 filing included an updated generation market power study that utilized original 2003 data as well as pertinent 2004 data. The results showed that, with the addition of Bennett Mountain, IPC still passed both of the FERC's market power screens in all relevant control areas.

On December 9, 2005, the FERC Staff requested that IPC perform a complete generation market power study for the IPC control area using 2004 data. IPC filed a revised study with the FERC on February 3, 2006.

The FERC accepted IPC's notice on June 20, 2006 confirming that IPC passed the market power analysis screens and maintained market-based rate authority.

OTHER MATTERS:

Adopted Accounting Pronouncements
SFAS 123(R): Effective January 1, 2006, IDACORP and IPC adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *"Share-Based Payment,"* (SFAS 123(R)) using the modified prospective application method. Prior to adopting SFAS 123(R), the companies accounted for stock-based employee compensation under the recognition and measurement principles of Accounting Principles Board Opinion 25, "*Accounting for Stock Issued to Employees,"* and related interpretations.

In 2004 and 2005, total stock-based employee compensation expense recorded was less than $1 million annually. IDACORP and IPC did not modify outstanding stock options prior to the adoption of SFAS 123(R), and the fair value estimation model for options did not differ significantly.

Since 2001, IDACORP and IPC have granted a mix of performance restricted stock, time-vesting restricted stock and stock options. In 2006, IDACORP and IPC granted cumulative earnings per share- and total shareholder return-based performance shares, and time-vesting restricted stock and granted only a minimal amount of stock options. The adoption of SFAS 123(R) did not have a material effect on IDACORP's and IPC's financial statements, and, based on current levels of awards, is not expected to have a material effect in the future. See Note 8 to IDACORP's and IPC's Consolidated Financial Statements for a discussion of the effects of adopting SFAS 123(R).

SFAS 158: In December 2006, IDACORP and IPC adopted SFAS 158, "*Employers' Accounting for Defined Benefit Pension Plans and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R).*" See Note 9 to IDACORP's and IPC's Consolidated Financial Statements for a discussion of the effects of adopting SFAS 158.

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SAB 108: In September 2006, the Securities and Exchange Commission (SEC) released Staff Accounting Bulletin No. 108, *"Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements"* (SAB 108). SAB 108 provides guidance on how the effects of the carryover or reversal of prior year financial statement misstatements should be considered in quantifying a current year misstatement. Prior practice allowed the evaluation of materiality on the basis of (1) the error quantified as the amount by which the current year income statement was misstated (rollover method) or (2) the cumulative error quantified as the cumulative amount by which the current year balance sheet was misstated (iron curtain method). Reliance on either method in prior years could have resulted in misstatement of the financial statements. The guidance provided in SAB 108 requires both methods to be used in evaluating materiality. Immaterial prior year errors may be corrected with the first filing of prior year financial statements after adoption. The cumulative effect of the correction would be reflected in the opening balance sheet with appropriate disclosure of the nature and amount of each individual error corrected in the cumulative adjustment, as well as a disclosure of the cause of the error and that the error had been deemed to be immaterial in the past. SAB 108 is effective for fiscal years ending after November 15, 2006. The adoption of SAB 108 did not have a material impact on IDACORP's or IPC's financial statements.

New Accounting Pronouncements

See Note 1 to IDACORP's and IPC's Consolidated Financial Statements for a discussion of recently issued accounting pronouncements.

Inflation

IDACORP and IPC believe that inflation has caused and will continue to cause increases in certain operating expenses and the replacement of assets at higher costs. Inflation affects the cost of labor, products and services required for operations, maintenance costs and capital improvements. While inflation has not had a significant impact on IDACORP's or IPC's operations, costs for products and services are subject to increases. IPC is subject to rate-of-return regulation and the impact of inflation on the level of cost recovery under regulation. Increases in utility costs and expenses due to inflation could have an adverse effect on earnings because of the need to obtain regulatory approval to recover such increased costs and expenses.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and IPC are exposed to various market risks, including changes in interest rates, changes in commodity prices, credit risk and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments and derivative commodity instruments sensitive to changes in interest rates, commodity prices and equity prices that were held at December 31, 2006.

Interest Rate Risk

IDACORP and IPC manage interest expense and short- and long-term liquidity though a combination of fixed rate and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly rated financial institutions may be used to achieve the desired combination.

Variable Rate Debt: As of December 31, 2006, IDACORP and IPC had $314 million and $241 million, respectively, in floating rate debt, net of temporary investments. Assuming no change in either company's financial structure, if variable interest rates were to average one percentage point higher than the average rate on December 31, 2006, interest expense would increase and pre-tax earnings would decrease by approximately $3.1 million for IDACORP and $2.4 million for IPC.

Fixed Rate Debt: As of December 31, 2006, IDACORP and IPC had outstanding fixed rate debt of $836 million and $797 million, respectively, and the fair market value of this debt was $828 million and $788 million, respectively. These instruments are fixed rate, and therefore do not expose IDACORP or IPC to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $67 million for IDACORP and $65 million for IPC if interest rates were to decline by one percentage point from their December 31, 2006 levels.

Commodity Price Risk

Utility: IPC's exposure to changes in commodity price is related to its ongoing utility operations producing electricity to meet the demand of its retail electric customers. The weather is a major uncontrollable factor affecting the local and regional demand for electricity and the availability and price of production. The objective of IPC's energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop.

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IPC's exposure to commodity price risk is largely offset by the previously discussed PCA mechanism. IPC has adopted a risk management program designed to reduce exposure to power supply cost-related uncertainty, further mitigating commodity price risk. This program has been reviewed and accepted by the IPUC. IPC's Energy Risk Management Policy (the Policy) describes a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of IPC officers and other senior staff, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to the IDACORP Board of Directors, and to the CAG.

The Policy requires monitoring monthly volumetric electricity position and total dollar (net power supply cost) exposure on a rolling 18-month forward view. The Power Supply business unit produces and evaluates projections of the operating plan and orders risk mitigating actions dictated by the limits stated in the Policy. The RMC evaluates the actions initiated by Power Supply for consistency and compliance with the Policy. IPC representatives meet with the CAG at least annually to assess effectiveness of the limits. Changes to the limits can be endorsed by the CAG and referred to the Board of Directors for approval. The primary tools for risk mitigation are physical forward power transactions and fueling alternatives for utility-owned generation resources.

Credit Risk

Utility: IPC is subject to credit risk based on its activity with market counterparties. IPC is exposed to this risk to the extent that a counterparty may fail to fulfill a contractual obligation to provide energy, purchase energy or complete financial settlement for market activities. IPC mitigates this exposure by actively establishing credit limits, measuring, monitoring, reporting, using appropriate contractual arrangements and transferring of credit risk through the use of financial guarantees, cash or letters of credit. A current list of acceptable counterparties and credit limits is maintained.

Equity Price Risk

IDACORP and IPC are exposed to price fluctuations in equity markets, primarily through their pension plan assets, a mine reclamation trust fund owned by an equity-method investment of IPC and other equity investments at IPC. A hypothetical ten percent decrease in equity prices would result in an approximate $2 million decrease in the fair value of financial instruments that are classified as available-for-sale securities.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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IDACORP, Inc.

Consolidated Statements of Income

	Year Ended December 31, 2006	2005	2004
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$ 636,375	$ 667,270	$ 635,835
Off-system sales	260,717	142,794	121,148
Other revenues	23,381	27,619	65,954
Total electric utility revenues	920,473	837,683	822,937
Other	5,818	5,181	4,919
Total operating revenues	926,291	842,864	827,856
Operating Expenses:			
Electric utility:			
Purchased power	283,440	222,310	195,642
Fuel expense	115,018	103,164	103,261
Power cost adjustment	(29,526)	(2,995)	39,184
Other operations and maintenance	256,553	241,209	255,867
Depreciation	99,824	101,485	100,855
Taxes other than income taxes	18,661	20,856	19,090
Total electric utility expenses	743,970	686,029	713,899
Other expense	12,617	2,182	7,724
Total operating expenses	756,587	688,211	721,623
Operating Income (Loss):			
Electric utility	176,503	151,654	109,038
Other	(6,799)	2,999	(2,805)
Total operating income	169,704	154,653	106,233
Other Income	18,195	17,121	25,456
Earnings (Losses) of Unconsolidated Equity-Method Investments	(2,913)	(713)	1,050
Other Expense	8,559	8,006	8,774
Interest Expense and Preferred Dividends:			
Interest on long-term debt	56,402	56,930	54,937
Other interest	4,573	2,799	3,375
Preferred dividends of Idaho Power Company	-	-	4,823
Total interest expense and preferred dividends	60,975	59,729	63,135
Income Before Income Taxes	115,452	103,326	60,830
Income Tax Expense (Benefit)	15,377	17,610	(19,951)
Income from Continuing Operations	100,075	85,716	80,781
Income (Losses) from Discontinued Operations, net of tax	7,328	(22,055)	(7,798)
Net Income	$ 107,403	$ 63,661	$ 72,983
	42,713	42,279	38,361

Weighted Average Common Shares Outstanding - Basic (000's)						
Weighted Average Common Shares Outstanding - Diluted (000's)		42,874		42,362		38,420
Earnings Per Share:						
Earnings per share from Continuing Operations-Basic	$	2.34	$	2.03	$	2.10
Earnings (loss) per share from Discontinued Operations-Basic		0.17		(0.52)		(0.20)
Earnings Per Share of Common Stock-Basic	$	2.51	$	1.51	$	1.90
Earnings per share from Continuing Operations-Diluted	$	2.34	$	2.02	$	2.10
Earnings (loss) per share from Discontinued Operations-Diluted		0.17		(0.52)		(0.20)
Earnings Per Share of Common Stock-Diluted	$	2.51	$	1.50	$	1.90
Dividends Paid Per Share of Common Stock	$	1.20	$	1.20	$	1.20

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.

Consolidated Balance Sheets

	December 31, 2006	December 31, 2005
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 9,892	$ 52,356
Receivables:		
Customer	62,131	94,469
Allowance for uncollectible accounts	(7,168)	(33,078)
Employee notes	2,569	2,951
Other	11,855	21,377
Energy marketing assets	12,069	23,859
Accrued unbilled revenues	31,365	38,905
Materials and supplies (at average cost)	39,079	30,451
Fuel stock (at average cost)	15,174	11,739
Prepayments	9,308	17,876
Deferred income taxes	28,035	23,922
Regulatory assets	1,480	3,064
Refundable income tax deposit	44,903	-
Other	2,513	2,956
Assets held for sale	3,326	6,673
Total current assets	266,531	297,520
Investments	202,825	191,593
Property, Plant and Equipment:		
Utility plant in service	3,583,694	3,477,067
Accumulated provision for depreciation	(1,406,210)	(1,364,640)
Utility plant in service - net	2,177,484	2,112,427
Construction work in progress	210,094	149,814
Utility plant held for future use	2,810	2,906
Other property, net of accumulated depreciation	28,692	29,294
Property, plant and equipment - net	2,419,080	2,294,441
Other Assets:		
American Falls and Milner water rights	30,543	31,585
Company-owned life insurance	34,055	35,401
Energy marketing assets - long-term	-	22,189
Regulatory assets	423,548	415,177
Long-term receivables (net of allowance of $1,878)	3,802	4,015
Employee notes	2,411	2,862

Other		41,259		43,377
Assets held for sale		21,076		25,966
Total other assets		556,694		580,572
Total	$	3,445,130	$	3,364,126

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.

Consolidated Balance Sheets

	December 31, 2006	December 31, 2005
Liabilities and Shareholders' Equity	(thousands of dollars)	
Current Liabilities:		
Current maturities of long-term debt	$ 95,125	$ 16,307
Notes payable	129,000	60,100
Accounts payable	86,440	80,324
Energy marketing liabilities	13,532	24,093
Taxes accrued	47,402	72,652
Interest accrued	12,657	14,616
Other	23,572	19,577
Liabilities held for sale	2,606	5,916
Total current liabilities	410,334	293,585
Other Liabilities:		
Deferred income taxes	498,512	519,563
Energy marketing liabilities - long-term	-	22,189
Regulatory liabilities	294,844	345,109
Other	179,836	124,833
Liabilities held for sale	8,773	10,051
Total other liabilities	981,965	1,021,745
Long-Term Debt	928,648	1,023,545
Commitments and Contingencies (Note 7)		
Shareholders' Equity:		
Common stock, no par value (shares authorized 120,000,000; 43,905,458 and 42,656,393 shares issued, respectively)	638,799	598,706
Retained earnings	493,363	437,284
Accumulated other comprehensive loss	(5,737)	(3,425)
Treasury stock (71,570 and 24,063 shares at cost, respectively)	(2,242)	(998)
Unearned compensation	-	(6,316)
Total shareholders' equity	1,124,183	1,025,251
Total	$ 3,445,130	$ 3,364,126

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.

Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2006	2005	2004
Operating Activities:	(thousands of dollars)		
Net income	$ 107,403	$ 63,661	$ 72,983
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	122,641	124,124	124,192
Deferred income taxes and investment tax credits	(17,332)	(31,769)	(33,912)
Changes in regulatory assets and liabilities	(17,133)	7,275	16,788
Undistributed (earnings) losses of subsidiaries	(9,553)	(16,762)	2,495
Provision for uncollectible accounts	106	(10,729)	(128)
Gain on sale of assets	(25,658)	(2,128)	(4,475)
Gain on extinguishment of debt	-	-	(7,188)
Impairment of goodwill	-	10,270	-
Impairment of long-lived asset	2,047	-	9,075
Other non-cash adjustments to net income	(3,501)	(4,344)	(3,117)
Excess tax benefit from share-based payment arrangements	(1,411)	-	-
Change in:			
Accounts receivable and prepayments	24,304	(6,436)	(1,314)
Accounts payable and other accrued liabilities	6,725	1,821	15,806
Taxes accrued	(24,099)	26,412	717
Other current assets	(4,829)	(14,360)	(4,568)
Other current liabilities	(3,465)	794	(1,309)
Other assets	3,334	(514)	2,058
Other liabilities	10,199	14,181	6,593
Net cash provided by operating activities	169,778	161,496	194,696
Investing Activities:			
Additions to property, plant and equipment	(225,048)	(193,314)	(199,770)
Sale of non-utility assets	146	1,019	5,554
Sale of ITI	21,469	-	-
Investments in affordable housing	(5,059)	(4,992)	(7,655)
Sale of emission allowances	11,323	70,757	-
Investments in unconsolidated affiliates	(16,030)	-	-
Purchase of available-for-sale securities	(17,979)	(85,334)	(295,356)
Sale of available-for-sale securities	20,778	120,026	266,331
Purchase of held-to-maturity securities	(2,730)	(2,181)	(4,927)
Maturity of held-to-maturity securities	4,647	2,840	7,730
Refundable income tax deposit	(44,903)	-	-
Other assets	346	2,229	-
Other liabilities	-	-	(1,547)
Net cash used in investing activities	(253,040)	(88,950)	(229,640)
Financing Activities:			
Issuance of long-term debt	116,300	64,992	106,442
Retirement of long-term debt	(132,642)	(83,067)	(79,890)
Retirement of preferred stock of IPC	-	-	(52,351)
Dividends on common stock	(51,272)	(50,690)	(45,838)
Change in short-term borrowings	68,900	23,830	(58,250)

Issuance of common stock		41,465		6,296		115,690
Acquisition of treasury stock		(213)		-		(1,420)
Excess tax benefit from share-based payment arrangements		1,411		-		-
Other assets		(3,058)		(4,486)		(1,145)
Other liabilities		(93)		(468)		(50)
Net cash provided by (used in) financing activities		40,798		(43,593)		(16,812)
Net increase (decrease) in cash and cash equivalents		(42,464)		28,953		(51,756)
Cash and cash equivalents at beginning of year		52,356		23,403		75,159
Cash and cash equivalents at end of year	$	9,892	$	52,356	$	23,403
Supplemental Disclosure of Cash Flow Information:						
Cash paid during the year for:						
Income taxes	$	54,522	$	18,937	$	7,742
Interest (net of amount capitalized)	$	60,353	$	57,466	$	55,122

The accompanying notes are an integral part of these statements.

IDACORP, Inc.

Consolidated Statements of Shareholders' Equity

	Common Stock Shares	Common Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Treasury Stock Amount	Total Amount
	(in thousands)						
Balance at January 1, 2004	38,341	$ 472,902	$ 397,167	$ (2,630)	111	$ (3,158)	$ 864,281
Net Income	-	-	72,983	-	-	-	72,983
Common stock dividends ($1.20 per share)	-	-	(45,838)	-	-	-	(45,838)
Issued	4,033	115,690	-	-	-	-	115,690
Acquired	-	-	-	-	46	(1,420)	(1,420)
Other	-	848	-	-	-	-	848
Unrealized gain on securities (net of tax)	-	-	-	862	-	-	862
Unfunded pension liability adjustment (net of tax)	-	-	-	880	-	-	880
Balance at December 31, 2004	42,374	589,440	424,312	(888)	157	(4,578)	1,008,286
Net Income	-	-	63,661	-	-	-	63,661
Common stock dividends ($1.20 per share)	-	-	(50,690)	-	-	-	(50,690)
Issued	282	8,204	-	-	(14)	431	8,635
Acquired	-	-	-	-	75	(2,268)	(2,268)
Other	-	1,062	1	-	21	(899)	164
Unrealized loss on securities (net of tax)	-	-	-	(1,812)	-	-	(1,812)
Unfunded pension liability adjustment (net of tax)	-	-	-	(725)	-	-	(725)
Balance at December 31, 2005	42,656	598,706	437,284	(3,425)	239	(7,314)	1,025,251

Net Income	-	-	107,403	-	-	-	107,403
Common stock dividends ($1.20 per share)	-	-	(51,323)	-	-	-	(51,323)
Issued	1,188	41,465	-	-	(11)	348	41,813
Acquired	-	-	-	-	6	(213)	(213)
Other	61	(1,372)	(1)	-	(162)	4,937	3,564
Unrealized loss on securities (net of tax)	-	-	-	(1,414)	-	-	(1,414)
Unfunded pension liability adjustment (net of tax)	-	-	-	2,118	-	-	2,118
Adjustment upon adoption of SFAS 158 (net of tax)	-	-	-	(3,016)	-	-	(3,016)
Balance at December 31, 2006	43,905	$ 638,799	$ 493,363	$ (5,737)	72	$ (2,242)	$ 1,124,183

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.

Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2006	**2005**	**2004**
	(thousands of dollars)		
Net Income	$ 107,403	$ 63,661	$ 72,983
Other Comprehensive Income (Loss):			
Unrealized gains (losses) on securities:			
Unrealized holding gains (losses) arising during the year, net of tax of $1,471, ($96) and $1,234	2,355	(457)	2,057
Reclassification adjustment for losses included in net income, net of tax of ($2,250), ($870) and ($768)	(3,769)	(1,355)	(1,195)
Net unrealized gains (losses)	(1,414)	(1,812)	862
Unfunded pension liability adjustment, net of tax of $1,359, ($465) and $565	2,118	(725)	880
Total Comprehensive Income	$ 108,107	$ 61,124	$ 74,725

The accompanying notes are an integral part of these statements.

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Idaho Power Company

Consolidated Statements of Income

	Year Ended December 31, 2006	2005	2004
	(thousands of dollars)		
Operating Revenues:			
General business	$ 636,375	$ 667,270	$ 635,835
Off-system sales	260,717	142,794	121,148
Other revenues	23,381	27,619	62,526
Total operating revenues	920,473	837,683	819,509
Operating Expenses:			
Operation:			
Purchased power	283,440	222,310	195,642
Fuel expense	115,018	103,164	103,261
Power cost adjustment	(29,526)	(2,995)	39,184
Other	191,833	181,670	194,073
Maintenance	64,720	59,539	58,405
Depreciation	99,824	101,485	100,855
Taxes other than income taxes	18,661	20,856	19,090
Total operating expenses	743,970	686,029	710,510
Income from Operations	176,503	151,654	108,999
Other Income (Expense):			
Allowance for equity funds used during construction	6,092	4,950	3,904
Earnings of unconsolidated equity-method investments	9,347	10,369	12,313
Other income	10,578	11,476	12,138
Other expense	(8,701)	(8,610)	(9,074)
Total other income	17,316	18,185	19,281
Interest Charges:			
Interest on long-term debt	53,744	53,339	50,317
Other interest	6,211	3,527	3,980
Allowance for borrowed funds used during construction	(4,026)	(2,791)	(2,953)
Total interest charges	55,929	54,075	51,344
Income Before Income Taxes	137,890	115,764	76,936
Income Tax Expense	43,961	43,925	6,328
Net Income	93,929	71,839	70,608
Dividends on preferred stock	-	-	4,823
Earnings on Common Stock	$ 93,929	$ 71,839	$ 65,785

The accompanying notes are an integral part of these statements.

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Idaho Power Company

Consolidated Balance Sheets

Assets	**December 31, 2006**	**2005**
Electric Plant:		
In service (at original cost)	$ 3,583,694	$ 3,477,067
Accumulated provision for depreciation	(1,406,210)	(1,364,640)
In service - net	2,177,484	2,112,427
Construction work in progress	210,094	149,814
Held for future use	2,810	2,906
Electric plant - net	2,390,388	2,265,147
Investments and Other Property	91,244	68,049
Current Assets:		
Cash and cash equivalents	2,404	49,335
Receivables:		
Customer	54,218	49,830
Allowance for uncollectible accounts	(968)	(833)
Notes	514	3,273
Employee notes	2,569	2,951
Related parties	-	637
Other	10,592	7,399
Accrued unbilled revenues	31,365	38,905
Materials and supplies (at average cost)	39,078	30,451
Fuel stock (at average cost)	15,174	11,739
Prepayments	8,952	17,532
Regulatory assets	1,480	3,064
Total current assets	165,378	214,283
Deferred Debits:		
American Falls and Milner water rights	30,543	31,585
Company-owned life insurance	34,055	35,401
Regulatory assets	423,548	415,177
Employee notes	2,411	2,862
Other	40,158	42,187
Total deferred debits	530,715	527,212
Total	$ 3,177,725	$ 3,074,691

The accompanying notes are an integral part of these statements.

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Idaho Power Company

Consolidated Balance Sheets

Capitalization and Liabilities

	December 31, 2006	December 31, 2005
	(thousands of dollars)	
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	530,758	483,707
Capital stock expense	(2,097)	(2,097)
Retained earnings	404,076	361,256
Accumulated other comprehensive loss	(5,737)	(3,425)
Total common stock equity	1,024,877	937,318
Long-term debt	902,884	983,720
Total capitalization	1,927,761	1,921,038
Current Liabilities:		
Long-term debt due within one year	81,064	-
Notes payable	52,200	-
Accounts payable	85,714	79,433
Notes and accounts payable to related parties	1,111	153
Taxes accrued	41,688	72,994
Interest accrued	12,324	14,105
Deferred income taxes	17	3,064
Other	24,367	19,182
Total current liabilities	298,485	188,931
Deferred Credits:		
Deferred income taxes	489,234	507,880
Regulatory liabilities	294,844	345,109
Other	167,401	111,733
Total deferred credits	951,479	964,722
Commitments and Contingencies (Note 7)		
Total	$ 3,177,725	$ 3,074,691

The accompanying notes are an integral part of these statements.

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Idaho Power Company

Consolidated Statements of Capitalization

	December 31, 2006	%	December 31, 2005	%
	(thousands of dollars)			
Common Stock Equity:				
Common stock	$ 97,877		$ 97,877	
Premium on capital stock	530,758		483,707	
Capital stock expense	(2,097)		(2,097)	
Retained earnings	404,076		361,256	
Accumulated other comprehensive loss	(5,737)		(3,425)	
Total common stock equity	1,024,877	53	937,318	49
Long-Term Debt:				
First mortgage bonds:				
7.38% Series due 2007	80,000		80,000	
7.20% Series due 2009	80,000		80,000	
6.60% Series due 2011	120,000		120,000	
4.75% Series due 2012	100,000		100,000	
4.25% Series due 2013	70,000		70,000	
6 % Series due 2032	100,000		100,000	
5.50% Series due 2033	70,000		70,000	
5.50% Series due 2034	50,000		50,000	
5.875% Series due 2034	55,000		55,000	
5.30% Series due 2035	60,000		60,000	
Total first mortgage bonds	785,000		785,000	
Amount due within one year	(80,000)		-	
Net first mortgage bonds	705,000		785,000	
Pollution control revenue bonds:				
Variable Auction Rate Series 2003 due 2024	49,800		49,800	
Variable Auction Rate Series 2006 due 2026	116,300		-	
6.05% Series 1996A due 2026	-		68,100	
Variable Rate Series 1996B due 2026	-		24,200	
Variable Rate Series 1996C due 2026	-		24,000	
Variable Rate Series 2000 due 2027	4,360		4,360	
Total pollution control revenue bonds	170,460		170,460	
American Falls bond guarantee	19,885		19,885	
Milner Dam note guarantee	11,700		11,700	
Note guarantee due within one year	(1,064)		-	
Unamortized premium/discount - net	(3,097)		(3,325)	
Total long-term debt	902,884	47	983,720	51

Total Capitalization	$	1,927,761	100	$	1,921,038	100

The accompanying notes are an integral part of these statements.

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Idaho Power Company

Consolidated Statements of Cash Flows

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	Year Ended December 31,		
	2006	**2005**	**2004**
Operating Activities:	(thousands of dollars)		
Net income	$ 93,929	$ 71,839	$ 70,608
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	105,464	107,919	108,551
Deferred income taxes and investment tax credits	(13,473)	(34,729)	(19,992)
Changes in regulatory assets and liabilities	(17,133)	7,275	16,788
Undistributed (earnings) losses of subsidiary	(9,347)	(16,669)	1,990
Provision for uncollectible accounts	106	(530)	(128)
Gain on sale of assets	(11,751)	(672)	-
Impairment of assets	2,047	-	9,075
Other non-cash adjustments to net income	(5,959)	(4,950)	(3,904)
Change in:			
Accounts receivables and prepayments	3,596	5,290	(3,718)
Accounts payable	6,623	2,578	29,112
Taxes accrued	(30,235)	30,766	(13,155)
Other current assets	(4,767)	(14,503)	(4,220)
Other current liabilities	(2,310)	1,269	(2,029)
Other assets	3,332	(698)	2,054
Other liabilities	10,997	11,840	6,753
Net cash provided by operating activities	131,119	166,025	197,785
Investing Activities:			
Additions to utility plant	(221,840)	(185,865)	(190,286)
Purchase of available-for-sale securities	(17,979)	(85,334)	(295,356)
Sale of available-for-sale securities	20,778	120,026	266,331
Sale of emission allowances	11,323	70,758	-
Investments in unconsolidated affiliate	(16,030)	-	-
Other assets	497	1,181	(38)
Net cash used in investing activities	(223,251)	(79,234)	(219,349)
Financing Activities:			
Issuance of long-term debt	116,300	60,000	105,000
Retirement of long-term debt	(116,300)	(60,000)	(51,105)
Retirement of preferred stock	-	-	(52,351)
Dividends on common stock	(51,109)	(50,690)	(46,413)
Dividends on preferred stock	-	-	(4,823)
Change in short term borrowings	52,200	-	-
Capital contribution from parent	47,050	-	85,920
Other assets	(3,058)	(4,445)	(1,145)
Other liabilities	118	-	129
Net cash provided by (used in) financing activities	45,201	(55,135)	35,212
Net increase (decrease) in cash and cash equivalents	(46,931)	31,656	13,648
Cash and cash equivalents at beginning of year	49,335	17,679	4,031

Cash and cash equivalents at end of year	$	2,404	$ 49,335	$	17,679
Supplemental Disclosure of Cash Flow Information:					
Cash paid during the year for:					
Income taxes paid to parent	$	86,311	$ 48,545	$	39,190
Interest (net of amount capitalized)	$	55,501	$ 51,290	$	48,113

The accompanying notes are an integral part of these statements.

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Idaho Power Company

Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2006	**2005**	**2004**
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 361,256	$ 340,107	$ 320,735
Net Income	93,929	71,839	70,608
Dividends			
Common stock	(51,109)	(50,690)	(46,413)
Preferred stock	-	-	(4,823)
Retained Earnings, End of Year	$ 404,076	$ 361,256	$ 340,107

The accompanying notes are an integral part of these statements.

Idaho Power Company

Consolidated Statements Comprehensive Income

	Year Ended December 31,		
	2006	**2005**	**2004**
	(thousands of dollars)		
Net Income	$ 93,929	$ 71,839	$ 70,608
Other Comprehensive Income (Loss):			
Unrealized gains (losses) on securities:			
Unrealized holding gains (losses) arising during the year, net of tax of $1,471, ($96) and $1,234	2,355	(457)	2,057

Reclassification adjustment for losses included in net income, net of tax of ($2,250), ($870) and ($768)	(3,769)	(1,355)	(1,195)
Net unrealized gains (losses)	(1,414)	(1,812)	862
Unfunded pension liability adjustment, net of tax of $1,359, ($465) and $565	2,118	(725)	880
Total Comprehensive Income	$ 94,633	$ 69,302	$ 72,350

The accompanying notes are an integral part of these statements.

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IDACORP, INC. AND IDAHO POWER COMPANY
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

This Annual Report on Form 10-K is a combined report of IDACORP, Inc. (IDACORP) and Idaho Power Company (IPC). Therefore, the Notes to the Consolidated Financial Statements apply to both IDACORP and IPC. However, IPC makes no representation as to the information relating to IDACORP's other operations.

Nature of Business
IDACORP is a holding company formed in 1998 whose principal operating subsidiary is IPC. IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005 (2005 Act), which provides certain access to books and records to the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions and imposes certain record retention and reporting requirements on IDACORP.

IPC is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. IPC is regulated by the FERC and the state regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co., a joint venturer in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

IDACORP's other subsidiaries include:

IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments;

Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and

IDACORP Energy (IE), a marketer of energy commodities, which wound down operations in 2003.

In the second quarter of 2006, IDACORP management designated the operations of IDACORP Technologies, Inc. (ITI) and IDACOMM as assets held for sale, as defined by Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"* (SFAS 144). IDACORP's consolidated financial statements reflect the reclassification of the results of these businesses as discontinued operations for all periods presented. Discontinued operations are discussed in more detail in Note 17.

On July 20, 2006, IDACORP completed the sale of all of the outstanding common stock of ITI to IdaTech UK Limited, a wholly-owned subsidiary of Investec Group Investments (UK) Limited.

On February 23, 2007, IDACORP completed the sale of all of the outstanding common stock of IDACOMM to American Fiber Systems, Inc.

Principles of Consolidation

The consolidated financial statements of IDACORP and IPC include the accounts of each company, consolidated subsidiaries and those variable interest entities (VIEs) for which the companies are the primary beneficiaries. All significant intercompany balances have been eliminated in consolidation. Investments in business entities in which IDACORP and IPC are not the primary beneficiaries, but have the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method.

The entities that IDACORP and IPC consolidate consist primarily of wholly-owned or controlled subsidiaries. In addition, IDACORP consolidates the following VIEs in accordance with Financial Accounting Standards Board Interpretation No. 46(R), *"Consolidation of Variable Interest Entities - an interpretation of ARB No. 51:"*

- Ida-West participates in Marysville Hydro Partners, a joint venture that owns a small hydroelectric project. Marysville Hydro Partners has approximately $22 million of assets, primarily the hydroelectric plant, and approximately $18 million of intercompany long-term debt, which is eliminated in consolidation.

IFS is a limited partner in Empire Development Company, LLC, an entity that earns historic tax credits through the rehabilitation of the Empire Building in Boise, Idaho. Empire Development Company, LLC has approximately $8 million of assets, primarily real property, and $7 million of long-term debt. This debt is non-recourse to IDACORP, personally guaranteed by the general partner and collateralized by the property.

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Through IFS, IDACORP also holds significant variable interests in VIEs for which it is not the primary beneficiary. These VIEs are historic rehabilitation and affordable housing developments in which IFS holds limited partnership interests ranging from five to 99 percent. These investments were acquired between 1996 and 2006. IFS's maximum exposure to loss in these developments totaled $90 million at December 31, 2006.

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, including those related to rate regulation, benefit costs, contingencies, litigation, asset impairment, income taxes, unbilled revenues and bad debt, 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.

System of Accounts

The accounting records of IPC conform to the Uniform System of Accounts prescribed by the FERC and adopted by the public utility commissions of Idaho, Oregon and Wyoming.

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 application of SFAS 71 by IPC can result in IPC recording expenses in a period different than the period the expense would be recorded 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.

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.

The effects of applying SFAS 71 are discussed in more detail in Note 12 - "Regulatory Matters."

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.

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. 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.

Property, Plant and Equipment and Depreciation
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.

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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 2.75 percent in 2006, 2.91 percent in 2005 and 2.96 percent in 2004.

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 SFAS 144. 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.

Goodwill

IDACORP accounts for goodwill in accordance with SFAS 142, "*Goodwill and Other Intangible Assets."* SFAS 142 requires that goodwill and certain intangible assets be tested for impairment at least annually and also under certain circumstances. The decision to exit one of IDACOMM's lines of business, broadband-over-power line, triggered a $10 million goodwill impairment charge in the fourth quarter of 2005. With the sale of ITI in July 2006, IDACORP no longer has any recorded goodwill.

Revenues

Operating revenues for IPC related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at period-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.

Allowance 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 2006, 2005 and 2004 were 7.6 percent, 7.4 percent and 6.9 percent, respectively. IPC's reductions to interest expense for AFDC were $4 million for 2006 and $3 million for both 2005 and 2004. Other income included $6 million, $5 million and $4 million of AFDC for 2006, 2005 and 2004, respectively.

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. See Note 2 for more information.

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.

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Earnings Per Share

The following table presents the computation of IDACORP's basic and diluted earnings per common share (in thousands, except for per share amounts):

	Year ended December 31, 2006	2005	2004
Numerator:			
Income from continuing operations	$ 100,075	$ 85,716	$ 80,781
Denominator:			
Weighted-average shares outstanding - basic*	42,713	42,279	38,361
Effect of dilutive securities:			
Options	93	49	57
Restricted Stock	68	34	2
Weighted-average shares outstanding - diluted	42,874	42,362	38,420
Basic earnings per share from continuing operations	$ 2.34	$ 2.03	$ 2.10
Diluted earnings per share from continuing operations	$ 2.34	$ 2.02	$ 2.10

*Weighted average shares outstanding excludes non-vested shares issued under stock compensation plans.

The diluted EPS computation excluded 538,950 options in 2006, 1,014,437 in 2005, and 818,600 in 2004 because the options' exercise prices were greater than the average market price of the common stock during those years. In total, 840,888 options were outstanding at December 31, 2006, with expiration dates between 2010 and 2015.

Stock-Based Compensation

Effective January 1, 2006, IDACORP and IPC adopted SFAS No. 123 (revised 2004), *"Share-Based Payment"* (SFAS 123(R)) using the modified prospective application method. SFAS 123(R) changes measurement, timing and disclosure rules relating to share-based payments, requiring that the fair value of all share-based payments be expensed. The adoption of SFAS 123(R) did not have a material impact on IDACORP's or IPC's financial statements for the year ended December 31, 2006.

IDACORP's and IPC's Consolidated Statements of Income for the years ended December 31, 2005 and 2004 do not reflect any changes from the adoption of SFAS 123(R). In those years, stock based employee compensation was accounted for under the recognition and measurement principles of Accounting Principles Board (APB) Opinion 25, *"Accounting for Stock Issued to Employees,"* and related interpretations.

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The following table illustrates what net income and earnings per share would have been had the fair value recognition provisions of SFAS 123 been applied to stock-based employee compensation in 2005 and 2004 (in thousands of dollars, except for per share amounts):

	2005	2004
IDACORP:		
Net income, as reported	$ 63,661	$ 72,983
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	359	399
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	1,214	1,169
Pro forma net income	$ 62,806	$ 72,213
EPS of common stock:		
Basic - as reported	$ 1.51	$ 1.90
Diluted - as reported	1.50	1.90
Basic - pro forma	1.49	1.88
Diluted - pro forma	1.48	1.88
IPC		
Net income, as reported	$ 71,839	$ 70,608
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	108	276
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	568	977
Pro forma net income	$ 71,379	$ 69,907

For purposes of these pro forma calculations, the estimated fair value of the options, restricted stock and performance shares is 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.

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 amounts related to pension plans. In 2006, IDACORP adopted SFAS 158 "*Accounting for Pension and Postretirement Costs - an amendment of FAS 87, 88, 106, and 132(R)*" which required the company to record additional amounts related to pension plans in other comprehensive income. SFAS 158 is discussed in more detail in Note 9. Prior to December 2005, other comprehensive income included the additional minimum liability related to a deferred compensation plan for certain senior management employees and directors. The following table presents IDACORP's and IPC's accumulated other comprehensive loss balance at December 31:

	2006	2005

	(thousands of dollars)	
Unrealized holding gains on securities	$ 1,311	$ 2,725
Defined benefit pension plans	(7,048)	(6,150)
Total	$ (5,737)	$ (3,425)

Other Accounting Policies

Debt discount, expense and premium are deferred and being amortized over the terms of the respective debt issues.

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Reclassifications
Certain items previously reported for years prior to 2006 have been reclassified to conform to the current year's presentation. Net income and shareholders' equity were not affected by these reclassifications.

New Accounting Pronouncements
FIN 48: In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 48, *"Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109*" (FIN 48), to create a single model to address accounting for uncertainty in tax positions. FIN 48 prescribes a minimum recognition threshold that a tax position is required to meet before being recognized in a company's financial statements and also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006.

IDACORP and IPC will adopt FIN 48 in the first quarter of 2007, as required. The cumulative effect of adopting FIN 48 will be recorded as an adjustment to 2007 opening retained earnings. IDACORP and IPC have not yet completed their evaluation of the effects the adoption of FIN 48 will have on their financial positions or results of operations.

SFAS 157: In September 2006, the FASB issued SFAS 157*, "Fair Value Measurements."* SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. IDACORP and IPC are currently evaluating the impact of adopting SFAS 157 on their financial statements.

SFAS 159: In February 2007, the FASB issued SFAS No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115"* (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to SFAS No. 115, *"Accounting for Certain Investments in Debt and Equity Securities,"* applies to all entities with available-for-sale and trading securities. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes that choice in the first 120 days of that fiscal year and also elects to apply the provisions of SFAS No. 157, *"Fair Value Measurements."* IDACORP and IPC are currently evaluating the impact of SFAS 159.

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2. INCOME TAXES:

A reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	IDACORP			IPC		
	2006	2005	2004	2006	2005	2004
	(thousands of dollars)					
Federal income tax expense at 35% statutory rate	$ 40,408	$ 36,165	$ 21,291	$ 48,262	$ 40,517	$ 26,928
Change in taxes resulting from:						
AFDC	(3,542)	(2,709)	(2,400)	(3,542)	(2,709)	(2,400)
Investment tax credits	(3,513)	(3,424)	(3,295)	(3,513)	(3,424)	(3,295)
Repair allowance	(2,450)	(1,750)	(2,450)	(2,450)	(1,750)	(2,450)
Removal costs	(1,912)	(1,490)	(1,244)	(1,912)	(1,490)	(1,244)
Pension accrual	1,902	1,276	1,237	1,902	1,276	1,237
Capitalized overhead costs	(2,940)	-	(3,658)	(2,940)	-	(3,658)
Tax accounting method change	6,122	-	-	6,122	-	-
Regulatory tax liability	-	-	(16,457)	-	-	(16,457)
Settlement of prior years' tax returns	(7,465)	-	(1,749)	(8,144)	-	(1,749)
State income taxes, net of federal benefit	5,287	5,399	3,461	6,501	6,173	4,100
Depreciation	5,757	5,603	4,350	5,757	5,603	4,350
Affordable housing and historic tax credits	(19,218)	(20,205)	(21,717)	-	-	-
Preferred dividends of IPC	-	-	1,688	-	-	-
Other, net	(3,059)	(1,255)	992	(2,082)	(271)	966
Total income tax expense (benefit)	$ 15,377	$ 17,610	$ (19,951)	$ 43,961	$ 43,925	$ 6,328
Effective tax rate	13.3%	17.0%	(32.8%)	31.9%	37.9%	8.2%

The items comprising income tax expense are as follows:

	IDACORP			IPC		
	2006	2005	2004	2006	2005	2004
	(thousands of dollars)					
Income taxes currently payable:						
Federal	$ 28,712	$ 42,236	$ 10,621	$ 52,142	$ 69,479	$ 19,003
State	4,254	8,097	3,949	5,293	9,176	7,317
Total	32,966	50,333	14,570	57,435	78,655	26,320
Income taxes deferred:						

Federal	(17,379)	(29,534)	(31,147)	(14,161)	(31,599)	(15,488)
State	(537)	(5,139)	(2,421)	360	(5,081)	(3,551)
Total	(17,916)	(34,673)	(33,568)	(13,801)	(36,680)	(19,039)
Investment tax credits:						
Deferred	3,840	5,374	2,342	3,840	5,374	2,342
Restored	(3,513)	(3,424)	(3,295)	(3,513)	(3,424)	(3,295)
Total	327	1,950	(953)	327	1,950	(953)
Total income tax expense (benefit)	$ 15,377	$ 17,610	$ (19,951)	$ 43,961	$ 43,925	$ 6,328

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The components of the net deferred tax liability are as follows:

	IDACORP		IPC	
	2006	2005	2006	2005
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 41,825	$ 41,627	$ 41,825	$ 41,627
Advances for construction	9,212	6,881	9,212	6,881
Deferred compensation	15,295	15,115	14,381	13,276
Emission allowances	12,175	27,380	12,175	27,380
Partnership investments	308	-	308	-
Retirement benefits	26,392	-	26,392	-
Tax credits	27,807	26,715	-	-
Other	16,863	16,122	13,154	14,496
Total	149,877	133,840	117,447	103,660
Deferred tax liabilities:				
Property, plant and equipment	230,361	240,144	230,361	240,144
Regulatory assets	343,590	346,117	343,590	346,117
Conservation programs	4,437	5,705	4,437	5,705
PCA	8,384	17,410	8,384	17,410
Partnership investments	13,656	18,768	-	3,892
Retirement benefits	18,055	-	18,055	-
Other	1,871	1,337	1,871	1,336
Total	620,354	629,481	606,698	614,604
Net deferred tax liabilities	$ 470,477	$ 495,641	$ 489,251	$ 510,944

IDACORP's tax allocation agreement provides that each member of its consolidated group compute its income taxes on a separate company basis. Amounts payable or refundable are settled through IDACORP.

Status of audit proceedings

In March 2005, the Internal Revenue Service (IRS) began its examination of IDACORP's 2001-2003 tax years. On October 13, 2006, the IRS issued its examination report and assessment for those years. With the exception of IPC's capitalized overhead costs method, discussed below, the IRS and IDACORP were able to settle all issues. The $1.6 million federal tax assessment for the settled issues was paid in November 2006. Interest charges and state income taxes have been accrued and are expected to be paid during 2007. Settlement of the agreed issues decreased 2006 income tax expense by $5.6 million at IDACORP and $6.2 million at IPC as the assessed deficiency was less than amounts previously accrued.

The IRS disallowed IPC's capitalized overhead cost method for uniform capitalization (the simplified service cost method) on the basis that IPC's self-constructed assets were not produced on a "routine and repetitive" basis as defined by Rev. Rul. 2005-53. The disallowance resulted in a federal tax assessment of $45 million. In November 2006 IDACORP filed a formal protest and request for an appeals conference. Also in November 2006, IDACORP made a refundable deposit of the disputed tax with the IRS to stop the accrual of interest. In December 2006, the IRS examination team filed its rebuttal to IDACORP's protest. In January 2007, IDACORP was notified that its case has been assigned to the IRS Appeals Office. IDACORP cannot predict the timing or outcome of this process, but believes that an adequate provision for income taxes and related interest charges has been made for this issue.

The simplified service cost method was also used for IPC's 2004 tax year. While 2004 is not currently under examination, it is likely the IRS will take the same position for 2004 as it did for 2001-2003; however, it is not likely that this position will result in a federal income tax assessment primarily due to the mitigating effect of accelerated tax depreciation.

On July 7, 2006, the IRS issued its examination report for Bridger Coal Company's 2001-2003 tax years. Bridger Coal is a partnership investment owned one-third by IPC. The audit resulted in net favorable adjustments to Bridger Coal's tax returns for those years. As a result of the settlement, IDACORP and IPC were able to decrease 2006 income tax expense by $1.9 million.

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In 2004, IDACORP completed settlement of all issues related to the IRS's examination of its federal income tax returns for the years 1998 through 2000. Concurrently, IPC settled federal income tax deficiencies for the years 1999 and 2000 related to its partnership investment in the Bridger Coal Company. Applicable state tax return amendments were completed in 2004 and settled. Finalization of these examinations resulted in deficiencies that were less than previously accrued, enabling IDACORP to decrease income tax expense by $1.7 million in 2004.

Capitalized overhead costs

Generally, section 263A of the Internal Revenue Code of 1986, as amended, requires the capitalization of all direct costs and indirect costs, including mixed service costs, which directly benefit or are incurred by reason of the production of property by a taxpayer. The simplified service cost method, a "safe harbor" method, is one of the methods provided by the section 263A treasury regulations for the calculation of mixed service cost capitalization. IPC adopted the simplified service cost method for both the self-construction of utility plant and production of electricity beginning with its 2001 federal income tax return.

On August 2, 2005, the IRS and the Treasury Department issued guidance interpreting the meaning of "routine and repetitive" for purposes of the simplified service cost and simplified production methods of the Internal Revenue Code section 263A uniform capitalization rules. The guidance was issued in the form of a revenue ruling (Rev. Rul. 2005-53) which is effective for all open tax years ending prior to August 2, 2005, and proposed and temporary regulations (the "Temporary Regulations") which are effective for tax years ending on or after August 2, 2005. Both pieces of guidance take a more restrictive view of the definition of self-constructed assets produced by a taxpayer on a "routine and repetitive" basis than did treasury regulations in effect at the time IPC changed to the simplified service cost method.

For IPC, the simplified service cost method produced a current tax deduction for costs capitalized to electricity production that are capitalized into fixed assets for financial accounting purposes. Deferred income tax expense had not been provided for this deduction because the prescribed regulatory tax accounting treatment does not allow for inclusion of such deferred tax expense in current rates. Rate regulated enterprises are required to recognize such adjustments as regulatory assets if it is probable that such amounts will be recovered from customers in future rates.

As discussed in "Status of Audit Proceedings" above, the IRS has disallowed IPC's use of the simplified service cost method for the tax years 2001-2003 on the basis of Rev. Rul. 2005-53. As a result, the IRS has assessed a $45 million tax liability. IDACORP is in the process of appealing the IRS's assessment. Because of the nature of the issue, IDACORP's exposure with respect to this matter may be less than the tax assessed plus applicable interest charges. Additionally, after resolution IDACORP will likely amend its 2005 federal income tax return and its 2005 method change application to account for the effects that such resolution has on IPC's new uniform capitalization method (discussed below). This amendment is not expected to have a material negative impact on IDACORP's or IPC's consolidated financial position, results of operations, or cash flows.

With respect to tax year 2005 and future tax years, the Temporary Regulations, as drafted, preclude IPC from using the simplified service cost method for its self-constructed assets. Under the Temporary Regulations, IPC is required to use another allowable section 263A method for its indirect costs, including mixed service costs. As a result of the Temporary Regulations, IPC made changes to its overall section 263A uniform capitalization method of accounting.

In September 2006, the changes were adopted with an automatic method change request included in IDACORP's 2005 federal income tax return. The uniform capitalization methodology adopted for 2005 and subsequent years involves the use of the specific identification, burden rate, and step-allocation methods of accounting. The methods used are allowable under both the final and temporary section 263A regulations.

As with the simplified service cost method, the new uniform capitalization methodology produces an annual tax deduction for costs that are not required to be capitalized under section 263A as well as costs capitalized into the production of electricity. The method, while producing a beneficial result, is not as favorable as the simplified service cost method. Changing the uniform capitalization method resulted in a net charge to IPC's 2006 income tax expense of $6.1 million. The estimated 2006 tax deduction produced a $3.3 million tax benefit for the year. The change in method did not have a material effect on IDACORP's or IPC's 2006 cash flows. The accounting and regulatory treatment for the new method is the same as previously used for the simplified service cost method.

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Regulatory Settlement
In 2004, IPC and the IPUC finalized an income tax issue from IPC's 2003 Idaho general rate case. The issue concerned the regulatory accounting treatment for the capitalized overhead tax method IPC adopted in the 2001 IDACORP federal income tax return. As a result of the settlement, a $16 million regulatory tax liability was reversed, creating a benefit in 2004.

Tax Credits Carrryforwards
As of December 31, 2006, IDACORP had $21.3 million of general business credit carryforward for federal income tax purposes and $5.9 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2025 to 2026 and the Idaho investment tax credit expires from 2019 to 2020.

3. COMMON STOCK:

IDACORP
The following table summarizes common stock issued and reserved:

	Shares issued			Shares reserved at
	2006	**2005**	**2004**	**December 31, 2006**
Dividend reinvestment and stock purchase plan	145,508	146,684	-	3,433,006
Employee savings plan	99,248	56,569	-	2,181,299
Restricted stock plan	-	-	-	314,114
Long-term incentive and compensation plan	467,791	79,383	7,400	2,545,426
Continuous equity program	536,518	-	-	1,963,482
Public offering	-	-	4,025,000	-
Total	1,249,065	282,636	4,032,400	10,437,327

On December 15, 2005, IDACORP entered into a Sales Agency Agreement with BNY Capital Markets, Inc. (BNYCMI). Under the terms of the Sales Agency Agreement, IDACORP may offer and sell up to 2,500,000 shares of its common stock, from time to time in at the market offerings through BNYCMI, as IDACORP's agent for such offer and sale. In the fourth quarter of 2006, IDACORP issued 536,518 shares of common stock in at the market offerings at an average price of $39.24 per share.

On January 1, 2006, IDACORP adopted SFAS 123(R), which requires that any amounts of unearned stock-based compensation be charged against common equity. Prior to January 1, 2006, IDACORP had aggregated its unearned compensation balances with treasury stock on its consolidated balance sheets.

Shareholder Rights Plan: IDACORP has a Shareholder Rights Plan (Plan) designed to ensure that all shareholders receive fair and equal treatment in the event of any proposal to acquire control of IDACORP. Under the Plan, IDACORP declared a distribution of one Preferred Share Purchase Right (Right) for each of its outstanding common shares held on October 1, 1998 or issued thereafter. The Rights are currently not exercisable and will be exercisable only if a person or group (Acquiring Person) either acquires ownership of 20 percent or more of IDACORP's voting stock or commences a tender offer that would result in ownership of 20 percent or more of such stock. IDACORP may redeem all, but not less than all, of the Rights at a price of $0.01 per Right or exchange the Rights for cash, securities (including common shares of IDACORP) or other assets at any time prior to the close of business on the tenth day after acquisition by an Acquiring Person of a 20 percent or greater position.

Additionally, the IDACORP Board of Directors created the A Series Preferred Stock, without par value, and reserved 1,200,000 shares for issuance upon exercise of the Rights.

Following the acquisition of a 20 percent or greater position, each Right will entitle its holder to purchase, for $95, that number of shares of common stock or preferred stock having a market value of $190. If after the Rights become exercisable, IDACORP is acquired in a merger or other business combination, 50 percent or more of its consolidated assets or earnings power are sold, or the Acquiring Person engages in certain acts of self-dealing, each Right entitles the holder to purchase, for $95, shares of the acquiring company's common stock having a market value of $190. Any Rights that are or were held by an Acquiring Person become void if any of these events occurs. The Rights expire on September 30, 2008.

The Rights themselves do not give their holders any voting or other rights as shareholders. The terms of the Rights may be amended without the approval of any holders of the Rights until an Acquiring Person obtains a 20 percent or greater position, and then may be amended as long as the amendment is not adverse to the interests of the holders of the Rights.

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Dividend Restrictions: IPC's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. On September 20, 2004, IPC redeemed all of its outstanding preferred stock. Also, certain provisions of credit facilities contain restrictions on the ratio of debt to total capitalization.

IPC must obtain the approval of the Oregon Public Utility Commission (OPUC) before it could directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

IPC

In December 2006, IDACORP contributed $47 million of additional equity to IPC. No additional shares of IPC common stock were issued.

4. LONG-TERM DEBT

The following table summarizes long-term debt at December 31:

	2006	**2005**
	(thousands of dollars)	
First mortgage bonds:		
7.38% Series due 2007	$ 80,000	$ 80,000
7.20% Series due 2009	80,000	80,000
6.60% Series due 2011	120,000	120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
Total first mortgage bonds	785,000	785,000
Pollution control revenue bonds:		
Variable Auction Rate Series 2003 due 2024 (a)	49,800	49,800
Variable Auction Rate Series 2006 due 2026 (a)	116,300	-
6.05% Series 1996A due 2026	-	68,100
Variable Rate Series 1996B due 2026	-	24,200
Variable Rate Series 1996C due 2026	-	24,000
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	11,700	11,700
Unamortized premium (discount) - net	(3,097)	(3,325)

Debt related to investments in affordable housing	32,331	48,481
Other subsidiary debt	7,494	7,686
Less: Liabilities held for sale	-	(35)
Total	1,023,773	1,039,852
Current maturities of long-term debt	(95,125)	(16,307)
Total long-term debt	$ 928,648	$ 1,023,545

(a) Humboldt County and Sweetwater County Pollution Control Revenue bonds are secured by first mortgage bonds, bringing the total first mortgage bonds outstanding at December 31, 2006, to $951.1 million.

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At December 31, 2006, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

	2007	2008	2009	2010	2011	Thereafter
IPC	$ 81,064	$ 1,064	$ 81,064	$ 1,064	$ 121,064	$ 701,725
Other subsidiary debt	14,061	10,392	5,657	2,965	220	6,530
Total	$ 95,125	$ 11,456	$ 86,721	$ 4,029	$ 121,284	$ 708,255

At December 31, 2006 and 2005, the overall effective cost of IPC's outstanding debt was 5.71 percent and 5.84 percent, respectively.

On October 3, 2006, IPC completed a tax-exempt bond financing in which Sweetwater County, Wyoming issued and sold $116.3 million aggregate principal amount of its Pollution Control Revenue Refunding Bonds Series 2006. The bonds will mature on July 15, 2026. The $116.3 million proceeds were loaned by Sweetwater County to IPC pursuant to a loan agreement, dated as of October 1, 2006, between Sweetwater County and IPC. On October 10, 2006, the proceeds of the new bonds, together with certain other moneys of IPC, were used to refund Sweetwater County's Pollution Control Revenue Refunding Bonds Series 1996A, Series 1996B and Series 1996C totaling $116.3 million. The regularly scheduled principal and interest payments on the Series 2006 bonds, and principal and interest payments on the bonds upon mandatory redemption on determination of taxability, are insured by a financial guaranty insurance policy issued by AMBAC Assurance Corporation. IPC and AMBAC have entered into an Insurance Agreement, dated as of October 3, 2006, pursuant to which IPC has agreed, among other things, to pay certain premiums to AMBAC and to reimburse AMBAC for any payments made under the policy. To secure its obligation to make principal and interest payments on the loan made to IPC, IPC issued and delivered to a trustee IPC's First Mortgage Bonds, Pollution Control Series C, in a principal amount equal to the amount of the new bonds.

At December 31, 2006, IFS had $32 million of debt related to investments in affordable housing. This debt had interest rates ranging from 3.65 percent to 8.38 percent and is due between 2007 and 2010. This debt is collateralized by investments in affordable housing developments with a net book value of $59 million at December 31, 2006. Of this $32 million in debt, $11 million is non-recourse to both IFS and IDACORP and the remainder is recourse only to IFS. IFS also has $5 million of debt related to a limited partnership investment. This debt is non-recourse to IDACORP, personally guaranteed by the general partner, and collateralized by property.

Long-Term Financing

IDACORP has $658 million remaining on two shelf registration statements that can be used for the issuance of unsecured debt (including medium-term notes) and preferred or common stock. IPC has in place a registration statement that can be used for the issuance of an aggregate principal amount of $240 million of first mortgage bonds (including medium-term notes) and unsecured debt.

In January 2007, the IPC Board of Directors approved an increase of the maximum amount of first mortgage bonds issuable by IPC to $1.5 billion. The amount issuable is also restricted by property, earnings and other provisions of the mortgage and supplemental indentures to the mortgage. IPC may amend the indenture and increase this amount without consent of the holders of the first mortgage bonds. The indenture requires that IPC's net earnings must be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that IPC may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

As of December 31, 2006, IPC could issue under the mortgage approximately $559 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, 2006, unfunded property additions were approximately $1.0 billion.

The mortgage requires IPC to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement or amortization of its properties. IPC may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

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The mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority or distinction. IPC may issue additional first mortgage bonds in the future, and those first mortgage bonds will also be secured by the mortgage. The lien of the indenture constitutes a first mortgage on all the properties of IPC, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of IPC are subject to easements, leases, contracts, covenants, workmen's compensation awards and similar encumbrances and minor defects and clouds common to properties. The mortgage does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The mortgage creates a lien on the interest of IPC in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger or sale of all or substantially all of the assets of IPC.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS:

The estimated fair value of IDACORP'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, 2006		**December 31, 2005**	
	Carrying Amount	**Estimated** Fair Value	**Carrying Amount**	**Estimated Fair Value**

	(thousands of dollars)			
IDACORP				
Assets:				
Notes receivable	$ 8,431	$ 8,257	$ 7,049	$ 6,879
Investments	39,109	39,074	34,510	34,514
Liabilities:				
Long-term debt	$ 1,026,870	$ 1,018,250	$ 1,043,248	$ 1,059,199
IPC				
Assets:				
Notes receivable	$ 5,853	$ 5,679	$ 7,047	$ 6,876
Investments	28,040	28,040	21,137	21,137
Liabilities:				
Long-term debt	$ 987,045	$ 978,491	$ 987,045	$ 1,003,651

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6. NOTES PAYABLE:

IDACORP has a $150 million credit facility and IPC has a $200 million credit facility that both expire on March 31, 2010. Commercial paper may be issued up to the amounts supported by the bank credit facilities. Under these facilities the companies pay 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. At December 31, 2006, IPC had regulatory authority to incur up to $250 million of short-term indebtedness. Balances and interest rates of IDACORP's short-term borrowings were as follows at December 31 (in thousands of dollars):

	IDACORP		IPC		Total	
	2006	**2005**	**2006**	**2005**	**2006**	**2005**
	(thousands of dollars)					
Balances:						
At the end of year	$ 76,800	$ 60,100	$ 52,200	$ -	$ 129,000	$ 60,100
Average during the year	$ 43,351	$ 53,030	$ 14,211	$ 123	$ 57,562	$ 53,153
Weighted-average interest rate:						
At the end of year	5.48%	4.47%	5.50%	-	5.49%	4.47%
Average during the year	5.05%	3.49%	5.50%	3.83%	5.15%	3.49%

7. COMMITMENTS AND CONTINGENCIES:

Purchase Obligations:

As of December 31, 2006, IPC had agreements to purchase energy from 92 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 911,132 megawatt-hours (MWh) at a cost of $54 million in 2006, 715,209 MWh at a cost of $46 million in 2005 and 677,868 MWh at a cost of $40 million in 2004.

At December 31, 2006, IPC had the following long-term commitments relating to purchases of energy, capacity, transmission rights and fuel:

	2007	2008	2009	2010	2011	Thereafter
	(thousands of dollars)					
Cogeneration and small power production	$ 45,130	$ 76,538	$ 76,538	$ 79,830	$ 79,830	$ 1,064,718
Power and transmission rights	80,175	16,351	7,390	2,781	2,754	13,315
Fuel	54,395	30,035	28,885	2,941	3,821	11,005

In addition, IDACORP has the following long-term commitments for lease guarantees, maintenance and services, and industry related fees.

	2007	2008	2009	2010	2011	Thereafter
			(thousands of dollars)			
Operating leases	$ 4,531	$ 4,666	$ 3,008	$ 2,059	$ 1,008	$ 8,991
Maintenance and service agreements	36,550	7,552	3,240	1,490	1,320	7,523
FERC and other industry related fees	3,970	4,008	4,008	3,970	3,970	19,926

IDACORP's expense for operating leases was approximately $4 million, $4 million and $5 million in 2006, 2005 and 2004, respectively.

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Guarantees
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, 2006. 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.

Legal Proceedings
From time to time IDACORP and IPC are a party to legal claims, actions and complaints in addition to those discussed below. IDACORP and IPC believe 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 the companies' evaluation, they believe that the resolution of these matters, taking into account existing reserves, will not have a material adverse effect on IDACORP's or IPC's 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 sitting by designation in the U.S. District Court for the Southern District of California. The companies' filed a motion to dismiss the complaint which the court granted on February 11, 2005. Wah Chang appealed the dismissal to the U.S. Court of Appeals for 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 and oral argument is scheduled for April 10, 2007. The companies intend 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 sitting by designation in the U.S. District Court for the Southern District of California. The companies' filed a motion to dismiss the complaint which the court granted on February 11, 2005. The City of Tacoma appealed to the U.S. Court of Appeals for the Ninth Circuit on March 10, 2005.

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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 and oral argument is scheduled for April 10, 2007. The companies intend 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. The CalPX owed 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 believed that the default invoices were not proper and that IPC owed no further amounts to the CalPX. IPC 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.

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 would await 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 was 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 were to be returned to the respective sellers at the conclusion of a seller's participation in the refund proceeding.

Based upon the Offer of Settlement filed with the FERC on February 17, 2006 between the California Parties and IE and IPC discussed below in "California Refund," the California Parties supported a motion filed by IE and IPC with the FERC seeking an Order Directing Return of Chargeback Amounts then held by the CalPX totaling $2.27 million. In the May 22, 2006 order approving the Settlement, the FERC granted the IE and IPC motion for return of chargeback funds held by the CalPX. On June 1, 2006, IE received approximately $2.5 million from the CalPX representing the return of $2.27 million in chargeback funds plus interest.

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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, were expected to increase the offsets to amounts still owed by the Cal ISO and the CalPX to the companies. Calculations remained uncertain because (1) the FERC had required the Cal ISO to correct a number of defects in its calculations, (2) it was 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 had stated that if refunds would prevent a seller from recovering its California portfolio costs during the Refund Period, it would provide an opportunity for a cost showing by such a respondent.

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.

Two avenues of activity have proceeded on largely but not entirely independent paths, converging from time to time. The Cal ISO continued to work on its compliance refund calculations while the appellate litigation and litigation before the FERC regarding, among other things, cost filings, fuel cost allowance offsets, emissions offsets, cost-based recovery offsets, and allocation methods continued.

Originally, the Cal ISO was to complete its calculation within five months of the FERC's October 16, 2003, order. The Cal ISO compliance filing has since been delayed numerous times. The Cal ISO has been required to update the FERC on its progress monthly. In its most recent status report, filed February 22, 2007, the Cal ISO reported that it has completed publishing settlement statements reflecting the basic refund calculations, and is currently in a "financial adjustment" phase, in which it calculates adjustments to its refund data to account for fuel cost allowance offsets, emissions offsets, cost-based recovery offsets, and interest on amounts unpaid and refunds. The Cal ISO estimates that it will take approximately 10 additional weeks to complete the financial adjustment phase, including applicable review and comment periods. The Cal ISO estimates that it will have completed its calculations by May 2007, subject to such additional time as may be required if unanticipated delays are encountered. The potential expansion of the FERC refund proceedings due to the Ninth Circuit orders and the disposition of additional settlements which the Ninth Circuit has announced it expects to be filed at the FERC in the near future may affect the finality of any Cal ISO calculations. At present, IDACORP and IPC are not able to predict when the Ninth Circuit mandates may issue, how the FERC will proceed in connection with the possible expansion of the proceedings, the nature and content of as yet un-filed settlements or the extent to which the Cal ISO calculation process may be disrupted.

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On December 2, 2003, IDACORP 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 a decision on the jurisdictional issues concluding that the FERC lacked refund authority over wholesale electric energy sales made by governmental entities and non-public utilities. On August 2, 2006, the Ninth Circuit issued its decision on the appropriate temporal reach and the type of transactions subject to the FERC refund orders and concluded, among other things, that all transactions at issue in the case that occurred within or as a result of the CalPX and the Cal ISO were the proper subject of refund proceedings; refused to expand the refund proceedings into the bilateral markets including transactions with the California Department of Water Resources; approved the refund effective date as October 2, 2000, but also required the FERC to consider whether refunds, including possibly market-wide refunds, should be required for an earlier time due to claims that some market participants had violated governing tariff obligations (although the decision did not specify when that time would start, the California Parties generally had sought further refunds starting May 1, 2000); and effectively expanded the scope of the refund proceeding to transactions within the CalPX and Cal ISO markets outside the 24-hour spot market and energy exchange transactions. The IDACORP settlement with the California Parties approved by the FERC on May 22, 2006, and discussed below anticipated the possibility of such an outcome and attempted to provide that the consideration exchanged among the settling parties also encompass the settling parties' claims in the event of such expansion of the proceedings.

The Ninth Circuit subsequently issued orders deferring the time for seeking rehearing of its order and holding the consolidated petitions for review in abeyance for a limited time in order to create an opportunity for unusual mediation proceedings managed jointly by the Court Mediator and FERC officials. The Ninth Circuit has since extended the deferral for the mediation effort.

IDACORP believes that these decisions should have no material effect on IDACORP under the terms of the IDACORP Settlement with the California Parties approved by the FERC on May 22, 2006.

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.

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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 remanding 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. On December 28, 2006, a number of sellers have filed a certiorari petition to the U.S. Supreme Court. The U.S. Supreme Court has not yet acted on that petition. On February 16, 2007, the Ninth Circuit announced that it was continuing to withhold the mandate until April 27, 2007.

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. At December 31, 2005, with respect to the CalPX chargeback and the California refund proceedings discussed above, the CalPX and the Cal ISO owed $14 million and $30 million, respectively, for energy sales made to them by IPC in November and December 2000.

On August 8, 2005, the FERC issued an Order establishing the framework for filings by sellers who elected to make 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 IE and IPC cost filing and those made by other parties. IPC and IE submitted reply comments on October 17, 2005. The California entities filed supplemental comments on October 24, 2005 and IPC and IE filed supplemental reply comments on October 27, 2005.

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's 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's 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 of a ruling on the cost filing 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. Other parties had until March 9, 2006 to elect to become additional settling parties. A number of parties, representing substantially less than the majority potential refund claims, chose to opt out of the settlement.

On March 27, 2006, the FERC issued an order rejecting the IE/IPC cost filing and on April 26, 2006, IE and IPC sought rehearing of the rejection. By order of April 27, 2006, the FERC tolled the time for what otherwise would have been required by statute to be a decision on the request for rehearing.

On May 12, 2006, the FERC issued an order determining the method that should be used to allocate amounts approved in cost filings, approving the methodology that IE and IPC and others had advocated prior to the time IE and IPC entered into the February 17, 2006 settlement - allocating cost offsets to buyers in proportion to the net refunds they are owed through the Cal ISO and CalPX markets. On June 12, 2006, the California Parties requested rehearing, urging the FERC to allocate the cost offsets to all purchasers from the Cal ISO and CalPX markets and not just to that limited subset of purchasers who are net refund recipients. On July 12, 2006, the FERC tolled the time to act on the request for rehearing and has not issued orders on rehearing since that time. IDACORP and IPC are unable to predict how or when the FERC might rule on the request for rehearing.

After consideration of comments, the FERC approved the February 17, 2006, Offer of Settlement on May 22, 2006. Under the terms of the settlement, IE and IPC assigned $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 that 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. Any excess funds remaining at the end of the case are to be returned to IDACORP. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement.

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On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the settlement. On July 10, 2006, IPC and IE and the California Parties filed a response to Port of Seattle's request for rehearing. On October 5, 2006, the FERC issued an order denying the Port of Seattle's request for rehearing. On October 24, 2006, the Port of Seattle petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC order denying their request for rehearing of the FERC order approving the settlement. The Ninth Circuit consolidated that review petition with the large number of review petitions already consolidated before it. On January 23, 2007, IPC and IE filed a motion to sever the Port of Seattle's petition for review from the bulk of cases pending in the Ninth Circuit with which it had been consolidated. IPC and IE also filed a motion to dismiss the Port of Seattle's petition for review. The Port of Seattle filed their answers in opposition to the motion to sever and the motion to dismiss on February 1, 2007, and IPC and IE replied on February 12, 2007. IDACORP and IPC are not able to predict when or how the Ninth Circuit might rule on the motions.

Prior to December of 2005, IE had accrued a reserve of $42 million. This reserve was calculated taking into account the uncertainty of collection from the CalPX and Cal ISO. In the fourth quarter of 2005, following the tentative agreement with the California Parties, IE reduced this reserve by $9.5 million to $32 million. Following payment of the $10.25 million to IE and IPC in June 2006, IE further reduced the reserve by $24.9 million to $7.1 million. This reserve was calculated taking into account several unresolved issues in the California refund proceeding.

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 January 1, 2000 through the beginning of the existing refund period (October 2, 2000) 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.

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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. Originally, eight parties requested rehearing of the FERC's March 3, 2004 order. 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. The Ninth Circuit has consolidated this case with other matters and are holding them in abeyance. IPC is not able to predict the outcome of the judicial determination of these issues.

The settlement between the California Parties and IE and IPC discussed above in the California Refund proceeding approved by the FERC on May 22, 2006, results in the California Parties and other settling parties withdrawing their requests for rehearing of IPC's and IE's settlement with the FERC Staff regarding allegations of "gaming". On October 11, 2006, the FERC issued an Order denying rehearing of its earlier approval of the "gaming" allegations, thereby effectively terminating the FERC investigations as to IPC and IE regarding bidding behavior, physical withholding of power and "gaming" without finding of wrongdoing. On October 24, 2006, the Port of Seattle appealed the FERC order to the U.S. Court of Appeals for the Ninth Circuit.

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.

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 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 requested 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.

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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 sought to intervene in the proceedings initiated by the petitions of others. On July 21, 2004, the City of Seattle submitted 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 sought to introduce before the FERC consisted of audio tapes of what purports to be Enron trader conversations containing inflammatory language. 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, and oral argument was held on January 8, 2007. The Settlement approved by the FERC on May 22, 2006, resolves all claims the California Parties have against IE and IPC in the Pacific Northwest refund proceeding. The settlement with Grays Harbor resolves all claims Grays Harbor has against IE and IPC in this proceeding. IE and IPC are unable to predict the outcome as to all other parties in this proceeding.

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006 reviewing the FERC's decisions not to require repricing of certain long term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. IDACORP and IPC are unable to predict whether parties to that case will seek a writ of certiorari or how or when the FERC might respond to these decisions.

Shareholder Lawsuit: On May 26, 2004 and June 22, 2004, respectively, two shareholder lawsuits were filed against IDACORP and certain of its directors and officers. The lawsuits, captioned Powell, et al. v. IDACORP, Inc., et al. and Shorthouse, et al. v. IDACORP, Inc., et al., raise largely similar allegations. The lawsuits are putative class actions brought on behalf of purchasers of IDACORP stock between February 1, 2002, and June 4, 2002, and were filed in the U.S. District Court for the District of Idaho. The named defendants in each suit, in addition to IDACORP, are Jon H. Miller, Jan B. Packwood, J. LaMont Keen and Darrel T. Anderson.

The complaints alleged that, during the purported class period, IDACORP and/or certain of its officers and/or directors made materially false and misleading statements or omissions about the company's financial outlook in violation of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as amended, and Rule 10b-5, thereby causing investors to purchase IDACORP's common stock at artificially inflated prices. More specifically, the complaints alleged that IDACORP failed to disclose and misrepresented the following material adverse facts which were known to defendants or recklessly disregarded by them: (1) IDACORP failed to appreciate the negative impact that lower volatility and reduced pricing spreads in the western wholesale energy market would have on its marketing subsidiary, IE; (2) IDACORP would be forced to limit its origination activities to shorter-term transactions due to increasing regulatory uncertainty and continued deterioration of creditworthy counterparties; (3) IDACORP failed to account for the fact that IPC may not recover from the lingering effects of the prior year's regional drought and (4) as a result of the foregoing, defendants lacked a reasonable basis for their positive statements about IDACORP and their earnings projections. The Powell complaint also alleged that the defendants' conduct artificially inflated the price of IDACORP's common stock. The actions seek an unspecified amount of damages, as well as other forms of relief. By order dated August 31, 2004, the court consolidated the Powell and Shorthouse cases for pretrial purposes, and ordered the plaintiffs to file a consolidated complaint within 60 days. On November 1, 2004, IDACORP and the directors and officers named above were served with a purported consolidated complaint captioned Powell, et al. v. IDACORP, Inc., et al., which was filed in the U.S. District Court for the District of Idaho.

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The new complaint alleged that during the class period IDACORP and/or certain of its officers and/or directors made materially false and misleading statements or omissions about its business operations, and specifically the IE financial outlook, in violation of Rule 10b-5, thereby causing investors to purchase IDACORP's common stock at artificially inflated prices. The new complaint alleged that IDACORP failed to disclose and misrepresented the following material adverse facts which were known to it or recklessly disregarded by it: (1) IDACORP falsely inflated the value of energy contracts held by IE in order to report higher revenues and profits; (2) IDACORP permitted IPC to inappropriately grant native load priority for certain energy transactions to IE; (3) IDACORP failed to file 13 ancillary service agreements involving the sale of power for resale in interstate commerce that it was required to file under Section 205 of the Federal Power Act; (4) IDACORP failed to file 1,182 contracts that IPC assigned to IE for the sale of power for resale in interstate commerce that IPC was required to file under Section 203 of the Federal Power Act; (5) IDACORP failed to ensure that IE provided appropriate compensation from IE to IPC for certain affiliated energy transactions; and (6) IDACORP permitted inappropriate sharing of certain energy pricing and transmission information between IPC and IE. These activities allegedly allowed IE to maintain a false perception of continued growth that inflated its earnings. In addition, the new complaint alleges that those earnings press releases, earnings release conference calls, analyst reports and revised earnings guidance releases issued during the class period were false and misleading. The action seeks an unspecified amount of damages, as well as other forms of relief. IDACORP and the other defendants filed a consolidated motion to dismiss on February 9, 2005, and the plaintiffs filed their opposition to the consolidated motion to dismiss on March 28, 2005. IDACORP and the other defendants filed their response to the plaintiff's opposition on April 29, 2005 and oral argument on the motion was held on May 19, 2005.

On September 14, 2005, Magistrate Judge Mikel H. Williams of the U.S. District Court for the District of Idaho issued a Report and Recommendation that the defendants' motion to dismiss be granted and that the case be dismissed. The Magistrate Judge determined that the plaintiffs did not satisfactorily plead loss causation (i.e., a causal connection between the alleged material misrepresentation and the loss) in conformance with the standards set forth in the recent United States Supreme Court decision of Dura Pharmaceuticals, Inc. v. Broudo, 544 U.S.336, 125 S. Ct. 1627 (2005). The Magistrate Judge also concluded that it would be futile to afford the plaintiffs an opportunity to file an amended complaint because it did not appear that they could cure the deficiencies in their pleadings. Each party filed objections to different parts of the Magistrate Judge's Report and Recommendation.

On March 29, 2006, the U.S. District Court for the District of Idaho (Judge Edward J. Lodge) issued an Order in this case (Powell v. IDACORP) adopting the Report and Recommendation of Magistrate Judge Williams issued on September 14, 2005, granting the defendants' (IDACORP and certain of its officers and directors) motion to dismiss because plaintiffs failed to satisfy the pleading requirements for loss causation. However, Judge Lodge modified the Report and Recommendation and ruled that plaintiffs had until May 1, 2006, to file an amended complaint only as to the loss causation element. On May 1, 2006, the plaintiffs filed an amended complaint. The defendants filed a motion to dismiss the amended complaint on June 16, 2006, asserting that the amended complaint still failed to satisfy the pleading requirements for loss causation. Briefing on this most recent motion to dismiss was completed on August 28, 2006, and oral argument was held on February 26, 2007.

IDACORP and the other defendants intend to defend themselves vigorously against the allegations. IDACORP cannot, however, predict the outcome of these matters.

Western Shoshone National Council: On April 10, 2006, the Western Shoshone National Council (which purports to be the governing body of the Western Shoshone Nation) and certain of its individual tribal members filed a First Amended Complaint and Demand for Jury Trial in the U.S. District Court for the District of Nevada, naming IPC and other unrelated entities as defendants.

Plaintiffs allege that IPC's ownership interest in certain land, minerals, water or other resources was converted and fraudulently conveyed from lands in which the plaintiffs had historical ownership rights and Indian title dating back to the 1860's or before. Although it is unclear from the complaint, it appears plaintiffs' claims relate primarily to lands within the state of Nevada. Plaintiffs seek a judgment declaring their title to land and other resources, disgorgement of profits from the sale or use of the land and resources, a decree declaring a constructive trust in favor of the plaintiffs of IPC's assets connected to the lands or resources, an accounting of money or things of value received from the sale or use of the lands or resources, monetary damages in an unspecified amount for waste and trespass and a judgment declaring that IPC has no right to possess or use the lands or resources.

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On May 1, 2006, IPC filed an Answer to plaintiffs' First Amended Complaint denying all liability to the plaintiffs and asserting certain affirmative defenses including collateral estoppel and res judicata, preemption, impossibility and impracticability, failure to join all real and necessary parties, and various defenses based on untimeliness. On June 19, 2006, IPC filed a motion to dismiss plaintiffs' First Amended Complaint, asserting, among other things, that the Court lacks subject matter jurisdiction and that plaintiffs failed to join an indispensable party (namely, the United States government). Briefing on the motion to dismiss was completed on September 28, 2006. Newly decided authority from the United States Court of Federal Claims in further support of IPC's motion to dismiss was filed on January 3, 2007. The Court has yet to act on the IPC motion to dismiss. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter.

Sierra Club Lawsuit - Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in federal district court in Cheyenne, Wyoming for alleged violations of the Clean Air Act's opacity standards (alleged violations of air pollution permit emission limits) at the Jim Bridger coal fired plant ("Plant") in Sweetwater County, Wyoming. IPC has a one-third ownership interest in the Plant. PacifiCorp owns a two-thirds interest and is the operator of the Plant. The complaint alleges thousands of violations and seeks declaratory and injunctive relief and civil penalties of $32,500 per day per violation as well as the costs of litigation, including reasonable attorney fees. IPC believes there are a number of defenses to the claims and intends to vigorously defend its interest in this matter, but is unable to predict its outcome and is unable to estimate the impact this may have on its consolidated financial positions, results of operations or cash flows.

8. STOCK-BASED COMPENSATION:

IDACORP has three share-based compensation plans. IDACORP's employee plans are the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth. IDACORP also has one non-employee plan, the Director Stock Plan (DSP). The purpose of the DSP is to increase directors' stock ownership through stock-based 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, 2006, the maximum number of shares available under the LTICP and RSP were 1,688,562 and 104,325, respectively. The following table shows the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to IPC for those costs associated with IPC's employees (in thousands of dollars):

	IDACORP			IPC		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Compensation cost	$ 2,692	$ 589	$ 656	$ 1,458	$ 178	$ 453
Income tax benefit	$ 1,053	$ 230	$ 257	$ 570	$ 70	$ 177

No equity compensation costs have been capitalized.

Stock awards: Restricted stock awards have vesting periods of up to four years. Restricted stock awards entitle the recipients to dividends and voting rights, and unvested shares are restricted to disposition and subject to forfeiture under certain circumstances. The fair value of restricted stock awards is measured based on the market price of the underlying common stock on the date of grant and charged to compensation expense over the vesting period based on the number of shares expected to vest.

Performance-based restricted stock awards have vesting periods of three years. Performance awards entitle the recipients to voting rights, and unvested shares are restricted to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. For awards granted prior to 2006, dividends were paid to recipients at the time they were paid on the common stock. Beginning with the 2006 awards, dividends are accumulated and will be paid out only on shares that eventually vest.

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The performance goals for the 2006 awards are independent of each other and equally weighted, and are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments, using an expected quarterly dividend of $0.30. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of restricted stock and performance share activity is presented below. IPC share amounts represent the portion of IDACORP amounts related to IPC employees:

	IDACORP			IPC		
	Number of Shares		Weighted-average Grant date Fair value	Number of Shares		Weighted-average Grant date Fair value
Nonvested shares at December 31, 2003	94,363	$	30.59	79,257	$	31.19
Shares granted	83,366		31.15	67,056		31.13
Shares forfeited	(30,931)		34.80	(23,914)		35.71
Shares vested	(2,076)		30.20	(2,076)		30.20
Nonvested shares at December 31, 2004	144,722	$	30.02	120,323	$	30.27
Shares granted	96,708		29.75	87,620		29.75
Shares forfeited	(26,328)		38.46	(24,804)		38.40
Shares vested	(251)		31.21	(251)		31.21
Nonvested shares at December 31, 2005	214,851	$	28.86	182,888	$	28.92
Shares granted	124,126		25.90	112,146		25.91
Shares forfeited	(115,569)		26.48	(91,538)		26.14
Shares vested	(19,200)		30.39	(19,200)		30.39
Nonvested shares at December 31, 2006	204,208	$	28.26	184,296	$	28.32

At December 31, 2006, IDACORP had $1.9 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. IPC's share of this amount was $1.7 million. These costs are expected to be recognized over a weighted-average period of 1.91 years. IDACORP uses original issue and/or treasury shares for these awards.

Stock options: Stock option awards are granted with exercise prices equal to the market value of the stock on the date of grant. The options have a term of 10 years from the grant date and vest over a five-year period. Upon adoption of SFAS 123(R) on January 1, 2006, the fair value of each option is amortized into compensation expense using graded-vesting. Beginning in 2006, stock options are not a significant component of share-based compensation awards under the LTICP.

The fair values of all stock option awards have been estimated as of the date of the grant by applying a binomial option pricing model. The application of this model involves assumptions that are judgmental and sensitive in the determination of compensation expense. The following key assumptions were used in determining the fair value of options granted:

	2006	2005	2004
Dividend yield, based on current dividend and stock price on grant date	3.7%	4.1%	3.9%
Expected stock price volatility, based on IDACORP historical volatility	18%	23%	29%
Risk-free interest rate based on U.S. Treasury composite rate	4.92%	4.22%	3.96%
Expected term based on the SEC "simplified" method	6.50 years	7 years	7 years

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IDACORP's and IPC's stock option transactions are summarized below. IPC share amounts represent the portion of IDACORP amounts related to IPC employees:

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (000s)
IDACORP				
Outstanding at December 31, 2003	1,145,400	$ 32.69	5.08	$ 7,313
Granted	187,850	31.06		
Exercised	(7,400)	22.92		
Forfeited	(57,300)	29.87		
Expired	(14,000)	39.78		
Outstanding at December 31, 2004	1,254,550	$ 32.55	5.33	$ 8,100
Granted	208,314	29.53		
Exercised	(16,400)	22.92		
Forfeited	(22,750)	31.12		
Expired	(1,800)	36.74		
Outstanding at December 31, 2005	1,421,914	$ 32.24	5.71	$ 9,560
Granted	9,905	31.86		
Exercised	(406,623)	29.25		
Forfeited	(162,632)	28.43		
Expired	(21,676)	34.31		
Outstanding at December 31, 2006	840,888	$ 34.36	5.63	$ 4,062
Vested or expected to vest at December 31, 2006	821,227	$ 34.49	5.60	$ 3,873
Exercisable at December 31, 2006	579,624	$ 36.71	5.02	$ 1,554
IPC				
Outstanding at December 31, 2003	886,800	$ 32.48	5.04	$ 5,897
Granted	110,500	31.21		
Exercised	(4,200)	22.92		
Forfeited	(30,900)	29.90		
Expired	(9,600)	39.91		
Outstanding at December 31, 2004	952,600	$ 32.38	5.24	$ 6,371
Granted	157,837	29.75		
Exercised	-	-		
Forfeited	(16,300)	30.27		
Expired	-	-		
Outstanding at December 31, 2005	1,094,137	$ 32.03	5.64	$ 7,634
Granted	-	-		
Exercised	(320,821)	29.83		
Forfeited	(142,625)	28.51		
Expired	(11,600)	39.89		
Outstanding at December 31, 2006	619,091	$ 33.84	5.71	$ 3,385
Vested or expected to vest at December 31, 2006	603,152	$ 33.97	5.67	$ 3,227
Exercisable at December 31, 2006	407,826	$ 36.44	5.04	$ 1,292

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The following table presents information about options granted and exercised (in thousands of dollars, except for weighted-average amounts):

	IDACORP			IPC		
	2006	2005	2004	2006	2005	2004
Weighted-average grant-date fair value	$ 9.96	$ 5.86	$ 7.84	$ -	$ 5.95	$ 7.93
Fair value of options vested	2,191	1,865	1,596	1,275	1,390	1,229
Intrinsic value of options exercised	3,771	104	44	2,883	-	22
Cash received from exercises	11,937	376	170	9,614	-	96
Tax benefits realized from exercises	1,474	41	17	1,127	-	9

As of December 31, 2006, there was $0.3 million of total unrecognized compensation cost related to stock options. These costs are expected to be recognized over a weighted average period of 2.51 years. IDACORP uses original issue and/or treasury shares to satisfy exercised options.

9. BENEFIT PLANS:

SFAS 158

In December 2006 IDACORP and IPC adopted the recognition provisions of Statement of Financial Accounting Standards No. 158, "*Employers' Accounting for Defined Benefit Pension Plans and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R).*"

The following table presents the incremental effect of applying SFAS 158 on individual line items in the Consolidated Balance Sheets of IDACORP at December 31, 2006:

	Before Application of Statement 158	Adjustments	After Application of Statement 158
		(thousands of dollars)	
Prepayments	$ 13,444	$ (4,136)	$ 9,308
Noncurrent regulatory assets	377,367	46,181	423,548
Other current assets	42,979	(1,720)	41,259
Total assets	3,404,805	40,325	3,445,130
Other current liabilities	21,197	2,375	23,572
Noncurrent deferred income taxes	504,260	(5,748)	498,512
Other liabilities	133,122	46,714	179,836
Total other liabilities	940,999	40,966	981,965
Accumulated other comprehensive income (loss)	(2,721)	(3,016)	(5,737)
Total shareholders' equity	1,127,199	(3,016)	1,124,183

The adjustments for IPC are the same as those presented for IDACORP. In accordance with regulatory accounting treatment under SFAS 71, amounts that otherwise would have been recorded in accumulated other comprehensive income have been recorded as regulatory assets for both the pension and postretirement plans.

The measurement provisions of SFAS 158 are not required to be adopted until 2008 and require that a company measure its plan assets and benefit obligations as of its balance sheet date. IPC already uses a December 31 measurement date for its plans, so adoption of the measurement provisions of SFAS 158 is not expected to have a material effect on IDACORP's or IPC's results of operations or cash flows.

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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 2006, 2005 or 2004. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

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.

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

	Pension Plan		Deferred Compensation Plan	
	2006	**2005**	**2006**	**2005**
		(thousands of dollars)		
Change in benefit obligation:				
Benefit obligation at January 1	$ 406,049	$ 374,333	$ 42,723	$ 38,645
Service cost	14,476	13,129	1,473	1,170
Interest cost	22,340	21,126	2,327	2,151
Actuarial loss (gain)	(2,827)	11,399	(2,857)	2,799
Benefits paid	(14,439)	(13,938)	(2,352)	(2,312)
Plan amendments	-	-	552	270
Benefit obligation at December 31	425,599	406,049	41,866	42,723
Change in plan assets:				
Fair value at January 1	368,053	356,217	-	-
Actual return on plan assets	47,310	25,774	-	-
Employer contributions	-	-	-	-
Benefit payments	(14,439)	(13,938)	-	-
Fair value at December 31	400,924	368,053	-	-
Unfunded status at end of year	(24,675)	(37,996)	(41,866)	(42,723)
Unrecognized actuarial loss	-	43,806	-	13,553
Unrecognized prior service cost	-	5,118	-	1,414
Net amount recognized	$ (24,675)	$ 10,928	$ (41,866)	$ (27,756)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$ -	$ -	$ (2,375)	$ -
Noncurrent liabilities	(24,675)	-	(39,491)	-
Prepaid (accrued) pension cost	-	10,928	-	(39,268)
Intangible asset	-	-	-	1,414

Accumulated other comprehensive income		-		-		-		10,098
Net amount recognized	$	(24,675)	$	10,928	$	(41,866)	$	(27,756)
Amounts recognized in accumulated other comprehensive income consist of:								
Net loss	$	24,356		-	$	9,853		-
Prior service cost		4,455		-		1,720		-
Subtotal		28,811		-		11,573		-
Less amount recorded as regulatory asset		(28,811)		-		-		-
Net amount recognized in accumulated other comprehensive income	$	-		-	$	11,573		-
Accumulated benefit obligation	$	350,434	$	340,007	$	38,634	$	39,268

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

	Pension Plan			Deferred Compensation Plan		
	2006	2005	2004	2006	2005	2004
	(thousands of dollars)					
Service cost	$ 14,476	$ 13,129	$ 11,809	$ 1,473	$ 1,170	$ 1,358
Interest cost	22,340	21,126	20,437	2,327	2,151	2,312
Expected return on assets	(30,817)	(29,690)	(27,935)	-	-	-
Amortization of net loss	129	-	-	844	689	878
Amortization of prior service cost	664	771	770	245	228	(361)
Amortization of transition asset	-	(126)	(263)	-	310	613
Net periodic pension cost	$ 6,792	$ 5,210	$ 4,818	$ 4,889	$ 4,548	$ 4,800

Changes in the Deferred Compensation Plan minimum liability increased other comprehensive income by $2 million in 2006 (prior to the effect of adopting SFAS 158), decreased other comprehensive income by $1 million in 2005 and increased other comprehensive income by $1 million in 2004.

In 2007, IDACORP and IPC expect to recognize as components of net periodic benefit cost $1.4 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2006, relating to the pension and deferred compensation plans. This amount consists of $0.6 million of prior service cost for the pension plan and $0.6 million of net loss and $0.2 million of prior service cost for the deferred compensation plan.

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

	2007	2008	2009	2010	2011	2012-2016
Pension Plan	$ 15,070	$ 16,127	$ 17,354	$ 18,858	$ 20,462	$ 133,740
Deferred Compensation Plan	$ 2,438	$ 2,546	$ 2,797	$ 2,997	$ 3,059	$ 16,963

Plan Asset Allocations: IPC's pension plan and postretirement benefit plan weighted average asset allocations at December 31, 2006 and 2005, by asset category are as follows:

	Pension Plan		Postretirement Benefits	
Asset Category	2006	2005	2006	2005
Equity securities	68%	66%	-%	-%
Debt securities	24	21	-	-
Real estate	7	10	-	-
Other (a)	1	3	100	100
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	5%	Short-Term Bonds	10%
Small-Cap Value Stocks	5%	Core Real Estate	9%
Micro-Cap Stocks	3%	Private Equity	2%
Cash and Cash Equivalents	3%		

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

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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 asset classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. 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. Benefits for employees who retire after December 31, 2002, are limited to a fixed amount, which 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):

	2006	2005	2004
Service cost	$ 1,463	$ 1,392	$ 1,400
Interest cost	3,426	3,381	3,974
Expected return on plan assets	(2,523)	(2,486)	(2,294)
Amortization of unrecognized transition obligation	2,040	2,040	2,040
Amortization of prior service cost	(535)	(535)	(523)
Amortization of net loss	812	754	1,489
Net periodic postretirement benefit cost	$ 4,683	$ 4,546	$ 6,086

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

		2006		2005
Change in accumulated benefit obligation:				
Benefit obligation at January 1	$	63,633	$	71,105
Service cost		1,463		1,392
Interest cost		3,426		3,381
Actuarial (gain) loss		(2,445)		(9,186)
Benefits paid		(3,164)		(2,934)
Plan amendments		-		(125)
Benefit obligation at December 31		62,913		63,633
Change in plan assets:				
Fair value of plan assets at January 1		29,893		29,723
Actual return on plan assets		3,158		1,127
Employer contributions		2,004		800
Benefits paid		(2,428)		(1,757)
Fair value of plan assets at December 31		32,627		29,893
Funded status at end of year		(30,286)		(33,740)
Unrecognized prior service cost		-		(3,677)
Unrecognized actuarial loss		-		15,978
Unrecognized transition obligation		-		14,280
Accrued benefit obligations included in noncurrent liabilities	$	(30,286)	$	(7,159)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$	12,086		
Prior service cost (credit)		(3,142)		
Transition obligation		12,240		
Subtotal		21,184		
Less amount recognized in regulatory assets		(17,370)		
Less amount included in deferred tax assets		(3,814)		
Net amount recognized in accumulated other comprehensive income	$	-		

In 2007, IDACORP and IPC expect to recognize as components of net periodic benefit cost $2.0 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2006 relating to the postretirement plan. This amount consists of $0.5 million of net loss, ($0.5) million of prior service cost and $2.0 million of transition obligation.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law in December 2003 and established 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 measure of net periodic benefit cost for the year ended December 31, 2004 does not reflect any amount associated with the subsidy.

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

	2007	2008	2009	2010	2011	2012-2016
Expected benefit payments*	$ 4,100	$ 4,200	$ 4,300	$ 4,500	$ 4,700	$ 25,300
Expected Medicare Part D subsidy receipts	$ 600	$ 600	$ 700	$ 800	$ 800	$ 3,200

*Expected benefit payments are net of expected Medicare Part D subsidy receipts.

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The assumed health care cost trend rate used to measure the expected cost of benefits covered by the plan was 6.75 percent in 2006 and 2005. 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	1-Percentage-Point decrease
Effect on total of cost components	$ 258	$ (195)
Effect on accumulated postretirement benefit obligation	$ 2,409	$ (1,897)

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	
	2006	2005	2006	2005
Discount rate	5.85%	5.6%	5.85%	5.6%
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 to determine net periodic benefit cost for all IPC-sponsored pension and postretirement benefit plans:

	Pension Benefits		Postretirement Benefits	
	2006	2005	2006	2005
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

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 both 2006 and 2005 and $3 million in 2004.

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. The post employment benefit amounts included in other deferred credits on IDACORP's and IPC's consolidated balance sheets at December 31 are $4.0 million and $3.8 million for 2006 and

2005, respectively.

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10. 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 2006 and 2005 (in thousands of dollars):

	2006		2005	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 1,592,790	2.55%	$ 1,563,008	2.54%
Transmission	606,947	2.18	580,382	2.19
Distribution	1,097,390	2.60	1,046,880	2.62
General and Other	286,567	6.74	286,797	8.94
Total in service	3,583,694	2.75%	3,477,067	2.91%
Accumulated provision for depreciation	(1,406,210)		(1,364,640)	
In service - net	$ 2,177,484		$ 2,112,427	

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, 2006 (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	$ 468,032	$ 7,890	$ 270,302	33	707
Boardman	Boardman, OR	69,109	476	47,284	10	59
Valmy Units 1 and 2	Winnemucca, NV	316,075	10,527	203,188	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. IPC's coal purchases from the joint venture were $52 million, $43 million and $47 million in 2006, 2005 and 2004, respectively.

IPC has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. IPC's power purchases from these facilities were $8 million in 2006 and $7 million annually in 2005 and 2004.

See Note 1 for a discussion of the property of IDACORP's consolidated VIEs.

11. SEGMENT INFORMATION:

Information regarding segments is presented in accordance with SFAS 131, *"Disclosure about Segments of an Enterprise and Related Information."* Based on the criteria outlined in SFAS 131, IDACORP has identified two reportable segments in 2006: utility operations and IFS. ITI and IDACOMM, which had previously been identified as reportable segments, are now reported as discontinued operations (see Note 17).

The utility operations segment's primary sources of revenue are the regulated operations of IPC. IPC's regulated operations include the generation, transmission, distribution, purchase and sale of electricity. This segment also includes income from Bridger Coal Company, an unconsolidated joint venture also subject to regulation. The IFS segment represents that subsidiary's investments in affordable housing developments and historic rehabilitation projects. Operating segments not included above are below the quantitative thresholds for reportable segments and are included in the "All Other" category. This category is comprised of Ida-West's joint venture investments in small hydroelectric generation projects, the remaining activities of energy marketer IE, which wound down its operations in 2003, and IDACORP's holding company expenses.

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The following table summarizes the segment information for IDACORP's utility operations and IFS and the total of all other segments, and reconciles this information to total enterprise amounts (in thousands of dollars):

-	Utility Operations	IFS	All Other	Eliminations 1	Consolidated Total
2006					
Revenues	$ 920,473	$ 1,375	$ 4,443	$ -	$ 926,291
Operating income (loss)	176,503	(389)	(6,410)	-	169,704
Other income	5,060	(41)	1,217	(490)	5,746
Interest income	2,909	1,295	1,399	(1,713)	3,890
Equity method income (loss)	9,347	(14,601)	2,341	-	(2,913)
Interest expense and preferred dividends	55,929	2,761	4,489	(2,204)	60,975
Income (loss) before income taxes	137,890	(16,497)	(5,941)	-	115,452
Income tax expense (benefit)	43,961	(26,005)	(2,579)	-	15,377
Income (loss) from continuing operations	93,929	9,509	(3,363)	-	100,075
Total assets	3,177,725	131,775	141,967	(6,337)	3,445,130
Expenditures for long- lived assets	221,930	5,065	28	-	227,023
2005					
Revenues	$ 837,683	$ 1,379	$ 3,802	$ -	$ 842,864
Operating income (loss)	151,654	(513)	3,512	-	154,653
Other income	4,623	368	786	(318)	5,459
Interest income	3,193	797	1,426	(1,760)	3,656
Equity method income (loss)	10,369	(12,851)	1,769	-	(713)
Interest expense and preferred dividends	54,075	3,691	4,041	(2,078)	59,729
Income (loss) before income taxes	115,764	(15,890)	3,452	-	103,326
Income tax expense (benefit)	43,925	(26,801)	486	-	17,610
Income from continuing operations	71,839	10,911	2,966	-	85,716
Total assets	3,074,691	139,305	184,039	(33,909)	3,364,126
Expenditures for long- lived assets	186,079	4,998	-	-	191,077
2004					
Revenues	$ 822,937	$ 1,392	$ 3,527	$ -	$ 827,856
Operating income (loss)	109,038	(544)	(2,261)	-	106,233
Other income	4,516	4,857	4,312	(69)	13,616
Interest income	2,413	655	893	(895)	3,066
Equity method income (loss)	12,313	(12,502)	1,239	-	1,050
Interest expense and preferred dividends	56,167	4,719	3,213	(964)	63,135
	72,113	(12,253)	970	-	60,830

Income (loss) before income taxes					
Income tax expense (benefit)	6,328	(25,566)	(713)	-	(19,951)
Income from continuing operations	65,785	13,313	1,683	-	80,781
Total assets	2,969,212	145,279	156,072	(36,392)	3,234,171
Expenditures for long- lived assets	190,379	7,670	101	-	198,150

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1 Includes assets of ITI and IDACOMM which are presented as assets held for sale.

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12. REGULATORY MATTERS:

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

	As of December 31, 2006					
Description	**Remaining Amortization Period**	**Earning a Return**	**Not Earning a Return**	**Pending Regulatory Treatment**	**2006 Total**	**As of December 31, 2005 Total**
Regulatory Assets:						
Income Taxes		$ -	$ 343,590	$ -	$ 343,590	$ 346,117
SFAS 158 (1)		-	46,181	-	46,181	-
Conservation	2010	11,349	-	-	11,349	14,592
PCA Deferral		-	-	-	-	32,251
Oregon Deferral (2)		9,559	-	-	9,559	11,291
Asset Retirement Obligations (3)		-	11,206	-	11,206	8,363
Tax Settlement Order		-	-	-	-	4,994
Grid West Loans		56	932	302	1,290	-
Other	Various thru 2008	390	1,463	-	1,853	633
Total		$ 21,354	$ 403,372	$ 302	$ 425,028	$ 418,241
Regulatory Liabilities:						
Income Taxes		$ -	$ 41,825	$ -	$ 41,825	$ 41,627
Conservation	2007	6,328	-	-	6,328	6,535
PCA Accrual (4)	2007	(11,852)	27,025	-	15,173	-
Asset Retirement Obligations (3)		-	156,162	-	156,162	152,683
Deferred ITC		-	69,114	-	69,114	68,786
IPUC Settlement Order		-	-	-	-	4,021
BPA Settlement		2,124	-	-	2,124	1,393
Emission Allowance		-	-	4,118	4,118	70,034
Other	Various thru 2007	-	-	-	-	30
Total		$ (3,400)	$ 294,126	$ 4,118	$ 294,844	$ 345,109

(1) See Note 9
(2) Capped at 10 percent increase per year.
(3) See Note 14
(4) Includes $69 million of emission allowances, of which $42.1 million earns a return and $27.0 million does not.

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.

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Deferred Power Supply Costs

Idaho: 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 portion, is then included in the calculation of the next year's PCA.

Idaho Load Growth Adjustment Rate (LGAR): In April 2006 IPC filed a petition with the IPUC requesting modification of one component of its PCA referred to as the Load Growth Adjustment Rate. The LGAR subtracts the cost of serving new Idaho retail customers from the power supply costs IPC is allowed to include in its PCA.

The LGAR was set at $16.84 per megawatt-hour when the PCA began in 1993. This amount was established as the projected marginal cost of serving each new customer and is subtracted from each year's PCA expense. In its April 2006 petition, IPC requested using the embedded cost of serving the new load rather than the projected marginal cost and to lower the rate to $6.81 per megawatt-hour. The IPUC Staff recommended against changing to the embedded cost approach; IPUC Staff also recommended increasing the rate to $40.87 per megawatt hour.

On January 9, 2007, the IPUC issued its final order in this matter. The IPUC maintained the marginal cost methodology and set the new LGAR at $29.41 per megawatt-hour. The new rate becomes effective on April 1, 2007 and will first affect customer rates on June 1, 2008.

The impact of the new LGAR on IPC will ultimately be determined by future load growth. Assuming an average 40 megawatt load growth, the new rate would result in approximately $10.3 million subtracted from the next PCA, a pre-tax increase of $4.4 million over the current amount. The impact of the new LGAR can be partially offset by IPC through more frequent general rate case filings with the IPUC or from less customer growth. In its order the IPUC stated that it expected IPC to update its load growth adjustment in all future general rate cases.

Oregon: The timing of recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent per year. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2001. Full recovery of the 2001 deferral is not expected until 2009. For the 2005-2006 deferral, a settlement stipulation drafted by the OPUC Staff provides that, instead of being amortized into rates, the deferral should be offset with the Oregon jurisdictional share of proceeds from the sale of SO_2 emission allowances and the benefit that IPC will receive from income taxes already paid on the sale of those allowances. An order is expected from the OPUC during the first quarter of 2007.

Emission Allowances: During 2005 and 2006, IPC sold 78,000 SO_2 emission allowances for approximately $81.6 million (before income taxes and expenses) on the open market. After subtracting transaction fees, the total amount of sales proceeds to be allocated to the Idaho jurisdiction was approximately $76.8 million ($46.8 million net of tax, assuming a tax rate of approximately 39 percent). The IPUC allowed IPC to retain ten percent, or approximately $4.7 million after tax, of the emission allowance net proceeds as a shareholder benefit. The remaining 90 percent of the sales proceeds ($69.1 million) plus a carrying charge will be recorded as a customer benefit. This customer benefit will be reflected in PCA rates during the June 1, 2007, through May 31, 2008, PCA rate year. The carrying charge will be calculated on $42.1 million, the net-of-tax amount allocable to Idaho jurisdiction customers.

As discussed above, a stipulation is currently before the OPUC which would offset SO_2 emission allowance proceeds against the 2005-2006 balance of Oregon deferred power supply costs. The stipulation allows for IPC to retain ten percent of the proceeds from emission allowance sales as a shareholder benefit.

Through allowance year 2006, IPC has approximately 36,000 excess allowances.

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

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		2006		2005
Idaho PCA current year:				
Deferral for the 2006-2007 rate year	$	-	$	3,684
Accrual for the 2007-2008 rate year*		(3,484)		-
Idaho PCA true-up awaiting recovery (refund):				
Authorized May 2005		-		28,567
Authorized May 2006		(11,689)		-
Oregon deferral:				
2001 costs		6,670		8,411
2005 costs		2,889		2,880
Total (accrual) deferral	$	(5,614)	$	43,542

*Includes $69 million of emission allowance sales to be credited to the customers during the 2007-2008 PCA year

Fixed Cost Adjustment Mechanism (FCA)

On January 27, 2006, IPC filed with the IPUC for authority to implement a rate adjustment mechanism that would adjust rates downward or upward to recover fixed costs independent from the volume of IPC's energy sales. This filing is a continuation of a 2004 case that was opened to investigate the financial disincentives to investment in energy efficiency by IPC. This true-up mechanism would be applicable only to residential and small general service customers. The first FCA rate change under this proposal would occur on June 1, 2007, coincident with IPC's PCA rate change. The accounting for the FCA will be separate from the PCA. As part of the filing, IPC proposes a three percent cap on any rate increase to be applied at the discretion of the IPUC.

On March 6, 2006, the IPUC reviewed IPC's proposal and acknowledged the intent of IPC and the IPUC Staff to initiate and engage in settlement discussions. The IPUC Staff presented an alternate view of IPC's proposal. Three workshops were held in 2006 and the parties have agreed in concept to a three-year pilot beginning at the first of the year and a stipulation was filed December 18, 2006. The stipulation calls for the implementation of a FCA mechanism pilot program as proposed by IPC in its original application with additional conditions and provisions related to customer count and weather normalization methodology, recording of the FCA deferral amount in reports to the IPUC and detailed reporting of DSM activities. The pilot program began on January 1, 2007, and will run through 2009, with the first rate adjustment to occur on June 1, 2008, and subsequent rate adjustments to occur on June 1 of each year thereafter during the term of the pilot program. The deadline for filing written comments with respect to the stipulation and the use of modified procedure was January 31, 2007. A final order is expected from the IPUC in the first quarter of 2007.

13. INVESTMENTS:

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

		2006		2005
IPC Investments:				
Equity method investment	$	62,223	$	38,764
Available-for-sale equity securities		21,548		21,137
Executive deferred compensation		6,492		6,201
Other investments		4		1,025

	Total IPC investments		90,267		67,127
Investments in affordable housing			90,266		99,972
Equity method investments			8,969		8,764
Held-to-maturity debt securities			11,069		13,373
Executive deferred compensation			4,767		5,313
Other investments			-		30
	Total IDACORP investments	$	205,338	$	194,579

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. Ida-West, through separate subsidiaries, owns 50 percent of each of the following electric generation projects: South Forks Joint Venture; Hazelton/Wilson Joint Venture and Snow Mountain Hydro LLC.

IFS invests in affordable housing developments that are accounted for in accordance with APB 18, *"The Equity Method of Accounting for Investments in Common Stock"* and Emerging Issues Task Force Issue 94-1, "*Accounting for Tax Benefits Resulting from Investments in Affordable Housing Projects,"* and are presented as Investments on the Consolidated Balance Sheets. All projects are reviewed periodically for impairment.

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

		2006		**2005**		**2004**
Bridger Coal Company (IPC)	$	9,347	$	10,369	$	12,313
Ida-West projects		2,341		1,769		1,239
IFS affordable housing projects		(14,601)		(12,851)		(12,502)
Total	$	(2,913)	$	(713)	$	1,050

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The following table presents summarized income statement information for Bridger Coal Company (in thousands of dollars):

	2006	2005	2004
Operating revenues	$ 154,910	$ 128,015	$ 138,329
Operating expenses	126,869	96,909	101,390
Net Income	$ 28,041	$ 31,106	$ 36,939

The following table presents summarized balance sheet information for Bridger Coal Company (in thousands of dollars):

	2006	2005
Assets		
Current assets	$ 47,723	$ 26,442
Noncurrent assets	325,252	262,909
Total Assets	$ 372,975	$ 289,351
Liabilities		
Current liabilities	$ 28,250	$ 17,728
Noncurrent liabilities	158,054	155,330
Total Liabilities	186,304	173,058
Joint venture capital	186,671	116,293
Total Liabilities and Joint Venture Capital	$ 372,975	$ 289,351

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.

Investments classified as held-to-maturity securities are reported at amortized cost. Held-to-maturity securities are investments in debt securities for which the company has the positive intent and ability to hold the securities until maturity. These debt securities have maturities ranging from 2007 through 2025

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

	2006			2005		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities (IPC)	$ 2,474	$ 322	$ 21,548	$ 2,925	$ 497	$ 21,137
Held-to-maturity debt securities (IFS)	5	40	11,034	354	350	13,377

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

	2006	2005	2004
Proceeds from sales	$ 20,778	$ 120,026	$ 266,331
Gross realized gains from sales	3,774	2,850	2,044
Gross realized losses from sales	280	643	634

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Additionally, these investments are evaluated to determine whether they have experienced a decline in market value that is considered other-than-temporary. IDACORP and IPC analyze 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. IDACORP and IPC have not recognized any other-than-temporary impairments in 2006, 2005 or 2004.

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).

	Less than 12 months		12 months or longer	
	Aggregate Unrealized Loss	**Aggregate Related Fair Value**	**Aggregate Unrealized Loss**	**Aggregate Related Fair Value**
2006:				
Available for sale equity securities (IPC)	$ 241	$ 3,879	$ 81	$ 621
Held to maturity debt securities (IFS)	9	578	31	2,278
2005:				
Available for sale equity securities (IPC)	$ 215	$ 1,731	$ 282	$ 1,423
Held to maturity debt securities (IFS)	17	1,817	333	4,128

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. The held-to-maturity debt securities in unrealized loss positions are bonds, whose market values fluctuate based on the interest rate environment. At December 31, 2006, 11 available-for-sale and six held-to-maturity securities were in an unrealized loss position. None of these securities had unrealized loss positions of greater than 20 percent. At December 31, 2005, nine available-for-sale and 11 held-to-maturity securities were in an unrealized loss position. Two available-for-sale securities had unrealized loss positions of greater than 20 percent. IDACORP and IPC do not consider these investments to be other-than-temporarily impaired at December 31, 2006 or 2005. Because IDACORP has the ability and intent to hold the debt securities until maturity, it does not consider them to be other-than-temporarily impaired at December 31, 2006 or 2005.

14. ASSET RETIREMENT OBLIGATIONS:

On January 1, 2003, IDACORP and IPC adopted SFAS 143, *"Accounting for Asset Retirement Obligations,"* requiring legal obligations associated with the retirement of property, plant and e