IDACORP INC
Form 8-K
June 08, 2009

**UNITED STATES**
**SECURITIES AND EXCHANGE COMMISSION**
**WASHINGTON, DC 20549**

**FORM 8-K**

**CURRENT REPORT**

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

Date of Report (Date of earliest event reported): May 26, 2009

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

State or Other Jurisdiction of Incorporation: Idaho

None
Former name or former address, if changed since last report.

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2.):

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

**IDACORP, Inc.**
**IDAHO POWER COMPANY**
**Form 8-K**

**ITEM 8.01 Other Events.**

Idaho and Oregon Rate Orders

Idaho Power Company (IPC) received six rate orders from the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC) at the end of May 2009, as described below. The IPUC rate orders are for the Fixed Cost Adjustment Mechanism, Idaho Energy Efficiency Rider, Advanced Metering Infrastructure, and Power Cost Adjustment, and the OPUC rate orders are for the Annual Power Cost Update and 2007-2008 Excess Power Supply Costs. Each of these orders increases rates, but only the Advanced Metering Infrastructure order involves an increase in IPC s rate base, relating to the installation of new meters.

1. Fixed Cost Adjustment Mechanism

On March 12, 2007, the IPUC approved the implementation of a Fixed Cost Adjustment Mechanism (FCA) pilot program for IPC s residential and small general service customers. The FCA is a rate mechanism designed to remove IPC s disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. In the FCA, for each customer class, the number of customers is multiplied by a fixed cost per customer. The cost per customer is based on IPC s revenue requirement as established in a general rate case. This authorized fixed cost recovery amount is compared to the amount of fixed costs actually recovered by IPC. The amount of over- or under-recovery is then returned to or collected from customers in a subsequent rate adjustment. The pilot program began on January 1, 2007 and runs through 2009, with the first rate adjustment effective June 1, 2008 and subsequent rate adjustments effective June 1 of each year during its term.

On March 13, 2009, IPC filed an application requesting a $5.2 million rate increase under the FCA pilot program for the net under-recovery of fixed costs during 2008, effective June 1, 2009 through May 31, 2010. On May 29, 2009, the IPUC approved IPC s application to increase rates under the FCA pilot program as filed.

2. Idaho Energy Efficiency Rider

On March 13, 2009, IPC filed an application with the IPUC requesting an increase to its Energy Efficiency Rider, which is the chief funding mechanism for IPC s investment in conservation, energy efficiency and demand response programs. IPC proposed an increase in Rider funding from 2.50 percent to 4.75 percent of base revenues, or based on 2008 test year revenue an increase of approximately $15.6 million annually, effective June 1, 2009. On May 29, 2009, the IPUC approved IPC s application to increase the Energy Efficiency Rider as filed. As a result of the IPUC approval, based on 2008 test year revenue, IPC expects Rider revenues of $27.3 million in 2009 and $33.2 million in each of 2010 and 2011.

3. Advanced Metering Infrastructure

The Advanced Metering Infrastructure (AMI) project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense.

On March 13, 2009, IPC filed an application with the IPUC requesting authority to increase its rates due to the inclusion of AMI investment in rate base. The filing requested inclusion of the investments already made for the installation of AMI throughout IPC s service territory, and those investments that would be made during a June 1, 2009 through May 31, 2010 test year.

IPC requested a first year revenue requirement of $11.2 million in the Idaho jurisdiction, effective June 1, 2009, for service provided on and after that date. In its calculations, IPC reflected the reduction in investment and the accelerated depreciation costs related to the removal of current metering equipment, as well as changes in operating expenses that accompany the changes in plant investment.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on IPC s actual investment in AMI to date, annualized through December 31, 2009, rather than IPC s proposed test year. The IPUC also allowed IPC to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. The actual depreciation expense for fiscal year 2009 will occur over seven months totaling $5.5 million.

4. Power Cost Adjustment

-

On April 15, 2009, IPC filed its 2009-2010 Power Cost Adjustment (PCA) application with the IPUC with a requested effective date of June 1, 2009. The filing requested an increase to existing revenues of approximately $93.8 million or 11.4 percent. IPC subsequently reduced its request, based upon its updated April operating plan, to approximately $84.3 million or 10.2 percent.

The 2009-2010 PCA reflects a new methodology, approved by the IPUC in Case No. IPC-E-08-19, that utilizes IPC s most recent operating plan to forecast power supply expenses rather than the previous method based on a forecast of Brownlee Reservoir inflow and a regression formula. On May 29, 2009, the IPUC approved the 2009-2010 PCA of $84.3 million or 10.2 percent, effective June 1, 2009.

5. Oregon Annual Power Cost Update

On October 23, 2008, IPC filed the October Update portion of its 2009 Annual Power Cost Update (APCU) with the OPUC. The filing, combined with supplemental testimony filed on December 1, 2008, reflects that revenues associated with IPC  s base net power supply costs would be increased by $1.6 million over the previous October Update, an average 4.55 percent increase. IPC and the OPUC Staff reached a verbal agreement on the October Update.

On March 20, 2009, IPC filed the March Forecast portion of its 2009 APCU.  When combined with the October Update, the March Forecast resulted in a requested increase to Oregon revenues of 11.46 percent, or $3.9 million annually.  A joint stipulation by IPC, the OPUC Staff and the Citizens   Utility Board in support of IPC  s requested increase was filed with the OPUC on May 4, 2009.  On May 26, 2009, the OPUC issued its order adopting the stipulation and approving the rate increases set forth in the stipulation effective on June 1, 2009.

6. Oregon 2007-2008 Excess Power Supply Costs

-

3

On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than normal (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon s jurisdictional share of excess power supply costs of $5.7 million. Settlement discussions were held in February 2009. As a result of those discussions, the parties to the proceeding reached a settlement and a stipulation was filed with the OPUC on April 8, 2009. In the stipulation, the parties agreed to limit the calculation of excess net power supply costs in this docket to the eight-month period from May 1 through December 31, 2007. Based on the methodology adopted by the parties to the stipulation, it was also determined that IPC should be allowed to defer excess net power supply costs of $5.5 million dollars for that period. The parties also agreed that the excess power supply costs from the period beginning in 2008 would be deferred pursuant to the Power Cost Adjustment Mechanism (PCAM) agreement established as part of the power cost variance filing for 2008 and calculated according to the PCAM. On May 28, 2009, the OPUC issued its order adopting the stipulation.

Hoku Electric Service Agreement

On September 17, 2008, IPC entered into an Electric Service Agreement (ESA) with Hoku Materials, Inc. (Hoku) to provide electric service to Hoku s polysilicon production facility in Pocatello, Idaho. The initial term of the agreement was four years, beginning June 1, 2009, with a maximum demand obligation during the initial term of 82 megawatts (MW). The IPUC approved the ESA on March 16, 2009.

On May 27, 2009, IPC and Hoku agreed to amend certain provisions of the ESA. Under their agreement, IPC and Hoku are to execute an ESA amendment agreement (ESA Amendment), which will be filed with the IPUC for approval. If approved by the IPUC, the ESA Amendment would delay the starting date for Hoku s required purchases of power under the ESA from June 1, 2009 to December 1, 2009. Under the ESA Amendment (i) IPC would provide electricity to Hoku at the current Schedule 19 Large Industrial tariff rate through November 30, 2009; (ii) Hoku would take no more than 5 MW of electric power through July 2009, 10 MW during August 2009 and 25 MW from September through November 2009; (iii) Hoku would take reduced levels of electric power of no more than 43 MW during the period June 16, 2012 through August 15, 2012 and 67 MW during the period August 16, 2009 through September 15, 2009; and (iv) Energy Efficiency Rider charges would be added to a portion of the electricity demand charges, beginning on December 1, 2011.

The ESA Amendment is not expected to have a material impact on IPC s 2009 earnings. While the six-month delay in the starting date for Hoku s required energy purchases will reduce IPC s 2009 revenues, this revenue reduction is expected to be largely offset by corresponding reductions in IPC s costs of providing service to Hoku. Any revenue reductions that are not offset by corresponding cost reductions would flow through IPC s power cost adjustment mechanism in Idaho, further reducing the impact on IPC s earnings.

Langley Gulch Intervenor Request for Stay

As previously reported, on March 6, 2009 IPC filed an application with the IPUC for a Certificate of Public Convenience and Necessity (CPCN) authorizing IPC to construct, own and operate the Langley Gulch power plant (Langley Gulch). Langley Gulch will be a natural gas-fired combined cycle combustion turbine generating plant to be constructed in Payette County, Idaho, with a generating capacity of approximately 300 MW in the summer and 330 MW in the winter. IPC requested in its CPCN application that the IPUC issue its order in the Langley Gulch CPCN case (Langley Gulch Case) by September 1, 2009.

On May 29, 2009 a joint motion was filed in the Langley Gulch Case by the Industrial Customers of Idaho Power, the Idaho Irrigation Pumpers Association, the Snake River Alliance, the Idaho Conservation League and the Northwest & Intermountain Power Producers Coalition, requesting that the IPUC stay the Langley Gulch Case for at least ten months (Request for Stay). The Request for Stay asserts that the stay should be granted by the IPUC because (1) IPC should first respond to the advisory shareholder proposal adopted by IDACORP s shareholders in May 2009, relating to reductions in IPC greenhouse gas emissions, (2) IPC s 2009 Integrated Resource Plan is not scheduled to be filed until December 2009, (3) IPC s request for IPUC ratemaking preapproval for Langley Gulch, based on Idaho s newly adopted rate commitment statute, increases the importance of the IPUC s decision on Langley Gulch, (4) IPC should be able to negotiate an extension, perhaps at additional cost, of the September 1, 2009 payment dates for the purchase of the Siemens turbines for Langley Gulch, (5) IPC has already delayed the on-line date for Langley Gulch from the summer of 2012 to December 2012, and IPC s next peak load following the summer of 2012 will not occur until the summer of 2013, (6) the continuing recession has reduced the demand for new IPC generation facilities, and the need for Langley Gulch should be reassessed when a general economic recovery has begun, (7) PacifiCorp is mothballing planned generation expansions, and (8) the impacts of IPC s demand response programs have not been ascertained.

IPC plans to oppose the Request for Stay. Delaying the IPUC decision date on the Langley Gulch CPCN for at least 10 months beyond September 1, 2009 would delay the 2012 in-service date for the project and jeopardize IPC s ability to meet customer loads in 2012 and beyond. Langley Gulch is scheduled to fill the key 2012 baseload resource requirement identified in IPC s current Integrated Resource Plan. IPC s updated customer load projections continue to show the need for Langley Gulch generation capacity by a 2012 project in-service date. Based on these current load projections, and based on IPC s discussions with the contractors performing the Langley Gulch Engineering, Procurement and Construction Services Agreement discussed below, IPC is working to advance the Langley Gulch in-service date from December 2012 to June 2012.

Delaying the IPUC CPCN decision beyond September 1, 2009 would also increase IPC s exposure to cancellation fees and non-refundable contract payments under IPC s gas turbine and steam turbine purchase agreements for Langley Gulch, as discussed below. The gas turbine and steam turbine are the largest equipment items for Langley Gulch, with a combined total purchase price of approximately $90 million.

Under the gas turbine purchase agreement with Siemens Energy (Gas Turbine Agreement), IPC s purchase of the gas turbine is subject to IPUC issuance of the CPCN by September 1, 2009, among other conditions. In the event IPC does not receive the CPCN by September 1, 2009, the Gas Turbine Agreement would automatically terminate, unless IPC and Siemens Energy reach an agreement within 30 days after that date to modify the contract price, equipment delivery schedule and other affected terms and conditions of the Gas Turbine Agreement. Upon such termination, IPC would be required to pay a cancellation fee of 35 percent of the total purchase price of the gas turbine, less any payments already made by IPC under the Gas Turbine Agreement. The Gas Turbine Agreement also contains a schedule of cancellation fees IPC must pay if it terminates the Gas Turbine Agreement at any time during the contract term, absent assignment of the Gas Turbine Agreement by IPC with the written consent of Siemens Energy. The cancellation fees are based on a percentage of the total gas turbine purchase price and increase monthly from 20 percent on July 1, 2009 to 100 percent on or after September 1, 2010.

The steam turbine purchase agreement with Siemens Energy (Steam Turbine Agreement) also contains a cancellation fee schedule.  IPC has the right to terminate the Steam Turbine Agreement at any time upon paying a cancellation fee to Siemens Energy based on a percentage of the total purchase price of the steam turbine, absent assignment of the Steam Turbine Agreement by IPC with the written consent of Siemens Energy.  The Steam Turbine Agreement cancellation fee percentage increases monthly from 10 percent on February 1, 2009 to 100 percent on or after May 1, 2011.  The cancellation fee is 15 percent on September 1, 2009.

IPC must also make non-refundable contract payments to Siemens Energy under the Gas Turbine Agreement beginning on September 1, 2009, in addition to its previous non-refundable reservation fee payment of $2.75 million. IPC s September 1, 2009 contract payment is approximately 20 percent of the total gas turbine purchase price, with additional monthly payments thereafter, concluding with the final contract payment on January 1, 2011. The cumulative amount of IPC s contract payments under the Gas Turbine Agreement would be offset against any cancellation fees owed by IPC under the Gas Turbine Agreement.

IPC must also make non-refundable contract payments to Siemens Energy under the Steam Turbine Agreement beginning on September 11, 2009, in addition to its previous non-refundable payments for the steam turbine - the reservation fee payment of approximately $2.9 million and the initial contract payment of approximately $3.1 million. IPC s September 11, 2009 contract payment is 14 percent of the total steam turbine purchase price, with additional contract payments due in March 2010, September 2010 and April 2011, and a smaller final contract payment due at final acceptance of the steam turbine. The cumulative amount of IPC s contract payments under the Steam Turbine Agreement would be offset against any cancellation fees owed by IPC under the Steam Turbine Agreement.

On May 7, 2009, IPC entered into an Engineering, Procurement and Construction Services Agreement (EPC Agreement) with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company (collectively, the Contractor), for design, engineering, procurement, construction management and construction services for Langley Gulch.

The EPC Agreement is the primary agreement governing the proposed development of Langley Gulch, providing for the specific design, engineering and construction work to be performed for Langley Gulch, as well as the equipment procurement required for the project. The total contract price to be paid by IPC under the EPC Agreement is approximately one-half of the projected $427 million total project cost for Langley Gulch.

The EPC Agreement provides that IPC is to issue a Full Notice to Proceed (FNTP) to the Contractor no later than September 1, 2009 to authorize the Contractor to commence and complete all work under the EPC Agreement. IPC plans to issue the FNTP by September 1, 2009 if it has (i) received an acceptable CPCN from the IPUC, (ii) received board approval and (iii) identified satisfactory financing options for the project at that time. The EPC Agreement provides that if IPC does not issue the FNTP by November 1, 2009, the Contractor may terminate the EPC Agreement, which termination will be without liability to either party other than for the Contractor s costs properly incurred pursuant to any work performed under the Master Services Agreement between IPC and the Contractor dated October 3, 2008. The amounts payable under the Master Services Agreement are not expected to be material to IPC.

IPC is required to make monthly progress payments to the Contractor under the EPC Agreement beginning in October 2009. The first twelve monthly progress payments between October 2009 and September 2010 will represent approximately one-fourth of the total payments scheduled to be made by IPC under the EPC Agreement. IPC may terminate the EPC Agreement at any time if it abandons the Langley Gulch project. Upon such termination, the Contractor is entitled to keep the progress payments previously paid by IPC, and IPC would be required to pay the value of the work completed to the date of termination not previously covered by IPC progress payments, plus a 15 percent markup on such costs.

Statement of Financial Accounting Standards No. 160

Effective January 1, 2009, IDACORP, Inc. adopted Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements* (SFAS 160) and FASB Staff Position EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securitie*s (FSP EITF 03-6-1).

6

SFAS 160 amended Accounting Research Bulletin No. 51, *Consolidated Financial Statements,* to establish accounting and reporting standards for a noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. The adoption of SFAS 160 did not have any material impact on IDACORP s financial condition and results of operations. However, it did impact the presentation and disclosure of noncontrolling (minority) interests in IDACORP s consolidated financial statements. The noncontrolling (minority) interests relate to third party stakeholders in two consolidated variable interest entities, Marysville Hydro Partners, LLC, and Empire Development, LLC.

Under the guidance in FSP EITF 03-6-1, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per share pursuant to the two-class method described in SFAS No. 128, *Earnings per Share.* The adoption of EITF 03-6-1 did not have a material impact on the consolidated financial statements of IDACORP.

As a result of the retrospective presentation and disclosure requirements of SFAS 160 and FSP EITF 03-6-1, IDACORP will be required to reflect the changes in presentation and disclosure for all periods presented in future filings of its periodic reports with the Securities and Exchange Commission. IDACORP determined that the accounting changes were not material to its previously issued financial statements. The following table summarizes the effects of the adoption of SFAS 160 and FSP EITF 03-6-1 on IDACORP s financial statements as of December 31, 2008 and 2007 and for the years ended December 31, 2008, 2007 and 2006 (in thousands, except per share amounts):

7

| | 2008 As Previously Reported | 2008 As Revised | 2007 As Previously Reported | 2007 As Revised | 2006 As Previously Reported | 2006 As Revised |
|---|---|---|---|---|---|---|
| **Consolidated Statements of Income:** | | | | | | |
| Other expense | $ 7,861 | $ 8,030 | $ 8,434 | $ 8,903 | $ 8,559 | $ 8,564 |
| Income before income taxes | 117,614 | 117,445 | 96,003 | 95,534 | 115,452 | 115,447 |
| Income from continuing operations | 98,414 | 98,245 | 82,272 | 81,803 | 100,075 | 100,070 |
| Net income | 98,414 | 98,245 | 82,339 | 81,870 | 107,403 | 107,398 |
| Net income attributable to IDACORP, Inc. (1) | - | 98,414 | - | 82,339 | - | 107,403 |
| Loss attributable to noncontrolling interests (1) | - | 169 | - | 469 | - | 5 |
| Earnings per share of common stock-basic (2) | 2.18 | - | 1.86 | - | 2.51 | - |
| Earnings per share of common stock-diluted (2) | 2.17 | - | 1.85 | - | 2.51 | - |
| Earnings per share of common stock: | | | | | | |
| Earnings attributable to IDACORP, Inc. - basic (1) | - | 2.17 | - | 1.86 | - | 2.51 |
| Earnings attributable to IDACORP, Inc. - diluted (1) | - | 2.17 | - | 1.85 | - | 2.5 |
| Net income | 98,414 | 98,245 | 82,339 | 81,870 | 107,403 | 107,398 |
| Total comprehensive income | 95,863 | 95,694 | 81,920 | 81,451 | 108,107 | 108,102 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Comprehensive loss attributable to noncontrolling interests (1) | - | 169 | - | 469 | - | 5 |
| Comprehensive income attributable to IDACORP, Inc.(1) | - | 95,863 | - | 81,920 | - | 108,107 |
| **Consolidated Statements of Cash Flows:** | | | | | | |
| *Operating Activities:* | | | | | | |
| Net income | 98,414 | 98,245 | 82,339 | 81,870 | 107,403 | 107,398 |
| Other liabilities | 4,182 | 4,013 | 13,098 | 12,629 | 10,199 | 10,194 |
| **Consolidated Statements of Shareholders Equity:** | | | | | | |
| Net income | 98,414 | 98,245 | 82,339 | 81,870 | 107,403 | 107,398 |
| Noncontrolling interest (1) | - | 4,434 | - | 4,478 | - | 5,062 |
| Total shareholders equity | 1,302,437 | 1,306,871 | 1,207,315 | 1,211,793 | 1,124,183 | 1,129,245 |
| **Consolidated Balance Sheets:** | | | | | | |
| Other liabilities-other | 349,304 | 344,870 | 173,412 | 168,934 | | |
| Total other liabilities | 1,141,289 | 1,136,855 | 913,798 | 909,320 | | |
| Noncontrolling interest (1) | - | 4,434 | - | 4,478 | | |
| Total IDACORP, Inc. shareholders equity (1) | - | 1,302,437 | - | 1,207,315 | | |
| Total shareholders equity | 1,302,437 | 1,306,871 | 1,207,315 | 1,211,793 | | |

(1) Represents a new financial statement line item included as a result of the application of SFAS 160.
(2) Represents a financial statement line item discontinued as a result of the application of SFAS 160.

-

-

-

-

-

-

-

8

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.

On May 31, 2007, the U.S. District Court granted the defendants motion to dismiss stating that the plaintiffs claims are barred by the finality provision of the Indian Claims Commission Act. Plaintiffs appealed the District Court s decision to the United States Court of Appeals for the Ninth Circuit. On June 4, 2009, the Ninth Circuit issued a Memorandum Opinion affirming the District Court s dismissal of the action. If further pursued by the plaintiffs, IPC intends to vigorously defend its position in this proceeding. IPC believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Certain statements contained in this Current Report on Form 8-K, including statements with respect to future earnings, ongoing operations, and financial conditions, are forward-looking statements within the meaning of federal securities laws. Although IDACORP and IPC believe that the expectations and assumptions reflected in these forward-looking statements are reasonable, these statements involve a number of risks and uncertainties, and actual results may differ materially from the results discussed in the statements. Factors that could cause actual results to differ materially from the forward-looking statements include: the effect of regulatory decisions by the Idaho Public Utilities Commission, the Oregon Public Utility Commission and the Federal Energy Regulatory Commission affecting our ability to recover costs and/or earn a reasonable rate of return including, but not limited to, the disallowance of costs that have been deferred; changes in and compliance with state and federal laws, policies and regulations including new interpretations by oversight bodies, which include the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the Idaho Public Utilities Commission and the Oregon Public Utility Commission, of existing policies and regulations that affect the cost of compliance, investigations and audits, penalties and costs of remediation that may or may not be recoverable through rates; changes in tax laws or related regulations or new interpretations of applicable law by the Internal Revenue Service or other taxing jurisdiction; litigation and regulatory proceedings, including those resulting from the energy situation in the western United States, and penalties and settlements that influence business and profitability; changes in and compliance with laws, regulations, and policies including changes in law and compliance with environmental, natural resources, endangered species and safety laws, regulations and policies and the adoption of laws and regulations addressing greenhouse gas emissions, global climate change, and energy policies; global climate change and regional weather variations affecting customer demand and hydroelectric generation; over-appropriation of surface and groundwater in the Snake River Basin resulting in reduced generation at hydroelectric facilities; construction of power generation, transmission and distribution facilities, including an inability to obtain required governmental permits and approvals, rights-of-way and siting, and risks related to contracting, construction and start-up; operation of power generating facilities including performance below expected levels, breakdown or failure of equipment, availability of transmission and fuel supply; changes in operating expenses and capital expenditures, including costs and availability of materials, fuel and commodities; blackouts or other disruptions of Idaho Power Company s transmission system or the western interconnected transmission system; population growth rates and other demographic patterns; market prices and demand for energy, including structural market changes; increases in uncollectible customer receivables; fluctuations in sources and uses of cash; results of financing efforts, including the ability to obtain financing or refinance existing debt when necessary or on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets and other economic conditions; actions by credit rating agencies, including changes in rating criteria and new interpretations of existing criteria; changes in interest rates or rates of inflation; performance of the stock market, interest rates, credit spreads and other financial market conditions, as well as changes in government regulations, which affect the amount and timing of required contributions to pension plans and the reported costs of providing pension and other postretirement benefits; increases in health care costs and the resulting effect on medical benefits paid for employees; increasing costs of insurance, changes in coverage terms and the ability to obtain insurance; homeland security, acts of war or terrorism; natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind and fire; 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 such forward-looking statements should be considered in light of such factors and others noted in the companies  Annual Report on Form 10-K for the year ended December 31, 2008, and other reports on file with the Securities and Exchange Commission. 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.

**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned hereunto duly authorized.

Dated: June 8, 2009

**IDACORP, Inc.**

By: *<u>/s/</u>* <u>Darrel T. Anderson</u>
Darrel T. Anderson
Senior Vice President -
Administrative Services
and Chief Financial Officer

**IDAHO POWER COMPANY**

By: *<u>/s/</u>* <u>Darrel T. Anderson</u>
Darrel T. Anderson
Senior Vice President -
Administrative Services
and Chief Financial Officer