IDAHO POWER CO
Form 8-K
March 04, 2010

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): February 24, 2010

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	82-0130980
	1221 W. Idaho Street	
	Boise, ID 83702-5627	
	(208) 388-2200	

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))

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Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

Short-Term Incentive Compensation

On February 26, 2010, the Compensation Committee (the Committee) of the Board of Directors (the Board) of IDACORP, Inc. (IDACORP) established 2010 short-term incentive award opportunities for executive officers and senior managers under the IDACORP, Inc. Executive Incentive Plan (the Plan) and amended Exhibit A to the Plan to reflect the performance goals for 2010. The Board approved Exhibit A as amended and the 2010 short-term incentive award opportunities at its meeting on February 26, 2010. A copy of Exhibit A as amended is filed as Exhibit 10.1 hereto. Filed as Exhibit 10.2 and incorporated herein by reference is the Executive Incentive Plan NEO 2010 Award Opportunity Chart indicating the 2010 short-term award opportunities for those executive officers who were named executive officers in the 2009 proxy statement for the Annual Meeting of Shareholders of IDACORP (the NEOs), except for Thomas R. Saldin and James C. Miller who retired in 2009.

The terms of the Plan provide for cash incentive award opportunities based upon IDACORP and Idaho Power Company (IPC) performance measures with a threshold, target and maximum level. The amount of incentive is calculated by multiplying base salary by the product of the approved incentive percentage and the combined multiplier. The maximum payout is 200% of target.

The goals for 2010 are a combination of (i) operational and customer service goals for IPC (weighted 30%) and (ii) consolidated net income for IDACORP, as adjusted (weighted 70%).

The first goal has two components: (i) customer satisfaction and (ii) network reliability for general service customers. Achievement of customer satisfaction, as measured by the customer relationship index, at the threshold level will result in a multiplier of 7.5%, at the target level will result in a multiplier of 15% and at the maximum level will result in a multiplier of 30%. Achievement of network reliability for general service customers (which is based on the number of service interruptions more than five minutes in duration and also requires that no more than 10% of customers have more than six interruptions) at the threshold level will result in a multiplier of 7.5%, at the target level will result in a multiplier of 15% and at the maximum level will result in a multiplier of 30%.

Achievement of the second goal, IDACORP consolidated net income, as adjusted, at the threshold level will result in a multiplier of 35%, at the target level will result in a multiplier of 70% and at the maximum level will result in a multiplier of 140%. Net income as reported in IDACORP s audited financial statements will be reduced by a percentage of any tax benefits over a predetermined dollar amount, without including the effects of sharing with Idaho customers any return on equity in excess of 10.5 percent pursuant to the January 2010 Idaho settlement agreement.

Participants who retire, die or become disabled during the year remain eligible to receive a prorated award to the extent performance goals are met. Participants who terminate employment for other reasons are not eligible for an award, unless otherwise determined by the Committee. The Committee assesses the extent to which goals have been achieved and recommends payment amounts to the Board. The Committee s recommendation may reflect downward adjustment of awards in light of such considerations as the Committee may deem relevant. An award is deemed earned and vested only when the Board approves payment of the award to the participant. No award may be paid under the Plan if there is no payment to employees under the IDACORP Employee Incentive Plan or if net income is less than the Board-approved dividend for IDACORP common stock for the calendar year to which the award relates.

In the event of a change in control, the Board has discretion, with respect to outstanding awards, to provide for assumption or substitution of the awards by the successor entity or to adjust performance goals and other terms of the awards as it deems appropriate. Under certain circumstances, the Board may approve vesting of all or a portion of the awards at target or another level determined by the Board or take such other action as the Board deems appropriate.

Participants who terminate employment for reasons other than cause after the date of a change in control shall be vested in either a prorated award or a full award in an amount determined by the Board.

Item 8.01 Other Events

Oregon General Rate Case Order

As previously reported, on December 17, 2009, Idaho Power Company (IPC) entered into a stipulation (Stipulation) with all active parties to IPC s general rate case filed with the Public Utility Commission of Oregon (OPUC) on July 31, 2009. On February 24, 2010, the OPUC issued its order approving the Stipulation, with certain exceptions related to residential rate design (Order). The Order and Stipulation are furnished as exhibits hereto.

Following is a summary of the main terms of the Stipulation as approved by the Order.

Rate Settlement. IPC s annual revenue requirement in Oregon will increase by approximately $5 million, for an overall rate increase in Oregon of approximately 15.4%. IPC implemented the approved rate increase on March 1, 2010, as authorized in the Order.

Rate of Return. IPC s return on equity is set at 10.175% for the Oregon jurisdiction, and its overall rate of return is set at 8.061% in Oregon. IPC s previously authorized rate of return in Oregon was 7.83%, and its requested rate of return in its general rate case filing was 8.68%.

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Advance Metering Infrastructure (AMI) Communication Equipment. The capital expense associated with IPC s AMI equipment is not included in the Stipulation rate increase, since AMI equipment has not yet been implemented in IPC s Oregon service territory. IPC will make a request to recover any prudently incurred investment in AMI equipment in Oregon in the future. In the event IPC receives smart grid funding for AMI equipment under the American Reinvestment and Recovery Act, such funds will be used as an offset to IPC s AMI investment, reducing the net rate base upon which future returns will be determined.

Net Power Supply Expense. On a going forward basis, the level of net power supply expense recovery included in IPC s base rates is $10.94 per MWh, and that rate will become the base from which future IPC Annual Power Cost Update rates will be determined.

Pension Expense. IPC will continue to account for pension expense on an accrual basis, a practice consistent with Statement of Financial Accounting Standards (SFAS) 87. It is not practicable for IPC to account for the difference in capitalized labor charges between jurisdictions with a fixed asset system, but IPC has historically capitalized a portion of its labor costs, including SFAS 87 expense. In order to simulate the historic accounting without creating an undue burden on IPC, IPC will be allowed to record the capital portion of its SFAS 87 expense as a regulatory asset to be amortized in a manner consistent with the depreciation of electric plant in service and revised by the OPUC for inclusion in rates in a subsequent rate proceeding. The capital portion of pension expense in the fixed-asset system will be removed from net plant to prevent double recovery of pension expenses.

The approved revenue requirement in the Order includes an SFAS pension expense. Going forward, the OPUC should recognize both a regulatory asset associated with the capital portion of pension expense and the non-capital pension expense component when determining the Company s revenue requirement. If this provision is adopted, IPC will withdraw its request to account for its pension expense on a cash basis.

Marginal Cost Methodology/Functionalization of Production Costs/Revenue Spread. IPC s marginal cost approach to allocating costs is appropriate and will be adopted with two exceptions: (1) at this time, transmission-related revenue requirement will be classified as 75percent demand-related and 25percent energy-related for the purpose of allocation to customer classes and (2) IPC has historically separated its embedded production costs into energy and demand components prior to their allocation. Instead, the functionalized production revenue requirement will be allocated directly and on the basis of each schedule s combined share of marginal demand and energy costs. Because a pure cost of service revenue requirement allocation would result in relatively large increases for Agricultural Irrigation Service and Traffic Control Lighting Service, the increases for those customer classes are capped at 75 percent of their cost of service, with the revenue shortfall being spread to all other customer classes with the exception of Large Power Service-Transmission Voltage Level and Area Lighting Service, which receive no increase.

Rate Design. IPC will utilize the rate design as proposed in its general rate case filing, with certain exceptions pertaining to IPC s residential service charge, residential block rate pricing, and small general service customer energy charges, all as described in the Stipulation. Also, see the Objections to the Stipulation discussion below regarding the Citizens Utility Board of Oregon (CUB) objections related to residential rate design.

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Other Provisions. The Order approves the changes to IPC s Oregon rules as set forth in the Stipulation. These rules include IPC s Rule F (Service Connection and Discontinuance), Rule H (New Service Attachments and Distribution Line Installations or Alterations) and Rule K (Customer s Load and Operations). The Order also approves the Stipulation provisions relating to IPC s service to Schedule 19 customers. The Order further references the agreement by the Oregon Industrial Customers of Idaho Power to remove its service quality issue from this proceeding and pursue it in a separate docket.

Objections to the Stipulation. CUB objected to the residential rate design portion of the Stipulation. The Order addresses CUB s objections relating to seasonal rates, tiered residential rates, customer service charge, reducing subsidies to irrigation customers, and length of billing cycles. In some cases the Order approves the treatment of these items as recommended in the Stipulation, and in other cases different treatment is ordered by the OPUC, as follows:

1. The Stipulation recommends the adoption of seasonal rates, including higher rates for residential customer usage above 1,000 kWh per month during summer months. The OPUC declines this recommendation in the Order, and instead calls for the issue to be addressed in a separate docket.

2. IPC currently has a two-tiered residential rate structure in Oregon, with the first rate block of lower rates extending up to 300 kWh per month. The Stipulation recommends raising this first rate block to 1,000 kWh per month, to cover the basic level of electricity usage by IPC s residential customers in Oregon. The OPUC declines this recommendation in the Order, stating that IPC s tiered rate structure should first be reviewed in connection with the review of IPC s seasonal rates.

3. The Stipulation recommends increasing IPC s customer service charge to $8.00 per month. This recommendation is adopted in the Order.

4. The Stipulation s rate spread provisions recommend increasing IPC s irrigation rates to 75% of the irrigators cost of service. CUB requested that IPC s irrigation rates be reviewed on a regular basis, as a part of IPC s Annual Power Cost Update and Power Cost Adjustment Mechanism proceedings, in order to eventually bring the irrigation rates up to the cost of service. The OPUC declines this request in the Order. The Order also states that IPC s proposed 27.96% irrigation rate increase under the Stipulation is reasonable.

5. IPC seeks to change its definition of billing cycle from 27 to 33 days to 27 to 36 days , and this change is approved in the Order.

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 Idaho Power Company 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, 2009, 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.

Item 9.01 Financial Statements and Exhibits

(d) Exhibits.

Number	**Description**
99.1	Order of the Public Utility Commission of Oregon dated February 24, 2010, in UE 213.
99.2	Stipulation, dated December 17, 2009, filed with the Public Utility Commission of Oregon in UE 213
10.1	Exhibit A to the IDACORP, Inc. Executive Incentive Plan, as amended February 26, 2010
10.2	IDACORP, Inc. Executive Incentive Plan NEO 2010 Award Opportunity Chart

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: March 4, 2010

IDACORP, Inc.

By: /s/ Rex Blackburn
Rex Blackburn
Senior Vice President and
General Counsel

IDAHO POWER COMPANY

By: /s/ Rex Blackburn
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