IDAHO POWER CO
Form 10-K
February 21, 2013
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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, 2012

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

State of incorporation: Idaho

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 Stock Exchange

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	(X)	No	( )	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 whether the registrants have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).
IDACORP, Inc. Yes (X) No ( ) Idaho Power Company 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)

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Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies.
IDACORP, Inc.:

Large accelerated filer(X)	Accelerated filer ( )	Non-accelerated filer ( )	Smaller reporting company ( )

Idaho Power Company:

Large accelerated filer( )	Accelerated filer ( )	Non-accelerated filer (X)	Smaller reporting company ( )

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 non-affiliates (June 30, 2012):
IDACORP, Inc.: $2,087,821,219 Idaho Power Company: None
Number of shares of common stock outstanding as of February 15, 2013:
IDACORP, Inc.: 50,143,416
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 2013 annual meeting of shareholders.
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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* Except as indicated in Items 10, 12, and 14, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2013 annual meeting of shareholders.

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COMMONLY USED TERMS

The following select abbreviations, terms, or acronyms are found in multiple locations within this report:

ADITC	-	Accumulated Deferred Investment Tax Credits	IESCo	-	IDACORP Energy Services Co., a subsidiary of IDACORP, Inc.
AFUDC	-	Allowance for Funds Used During Construction	IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
AMI	-	Advanced Metering Infrastructure	IPUC	-	Idaho Public Utilities Commission
aMW	-	Average Megawatts	IRP	-	Integrated Resource Plan
APCU	-	Annual Power Cost Update	IRS	-	U.S. Internal Revenue Service
BACT	-	Best Available Control Technology	kW	-	Kilowatt
BCC	-	Bridger Coal Company, a joint venture of IERCo	LCAR	-	Load Change Adjustment Rate
BLM	-	U.S. Bureau of Land Management	MACT	-	Utility Maximum Available Control Technology
BPA	-	Bonneville Power Administration	MD&A	-	Management's Discussion and Analysis of Financial Condition and Results of Operations
CAA	-	Clean Air Act	MW	-	Megawatt
CAMP	-	Comprehensive Aquifer Management Plan	MWh	-	Megawatt-hour
CO_2	-	Carbon Dioxide	NAAQS	-	National Ambient Air Quality Standards
CWA	-	Clean Water Act	NOAA	-	National Oceanic and Atmospheric Administration
DOE	-	U.S. Department of Energy	NOx	-	Nitrous Oxide
DSM	-	Demand-Side Management	NSPS	-	New Source Performance Standards
EGUs	-	Electric Utility Generating Units	NSR/PSD	-	New Source Review / Prevention of Significant Deterioration
EIS	-	Environmental Impact Statement	O&M	-	Operations and Maintenance
EPA	-	U.S. Environmental Protection Agency	OATT	-	Open Access Transmission Tariff
EPS	-	Earnings Per Share	OPUC	-	Oregon Public Utility Commission
ESA	-	Endangered Species Act	PCA	-	Power Cost Adjustment
FASB	-	Financial Accounting Standards Board	PCAM	-	Power Cost Adjustment Mechanism
FCA	-	Fixed Cost Adjustment Mechanism	PURPA	-	Public Utility Regulatory Policies Act of 1978
FERC	-	Federal Energy Regulatory Commission	REC	-	Renewable Energy Certificate
FPA	-	Federal Power Act	RES	-	Renewable Energy Standard
GAAP	-	Generally Accepted Accounting Principles	RPS	-	Renewable Portfolio Standard
GHG	-	Greenhouse Gas	SEC	-	U.S. Securities and Exchange Commission
HAPS	-	Hazardous Air Pollutants	SMSP	-	Senior Management Security Plan
HCC	-	Hells Canyon Complex	SO_2	-	Sulfur Dioxide
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.	USBR	-	U.S. Bureau of Reclamation
Idaho ROE	-	Idaho-jurisdiction return on year-end equity	USFWS	-	U.S. Fish and Wildlife Service
IERCo	-	Idaho Energy Resources Co., a subsidiary of Idaho Power Company	VIEs	-	Variable Interest Entities

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

In addition to the historical information contained in this report, this report contains (and oral communications made by IDACORP, Inc. and Idaho Power Company may contain) statements that relate to future events and expectations and, as such, constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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," "targets" "may result," "may continue," or similar expressions, are not statements of historical facts and may be forward-looking. Forward-looking statements are not guarantees of future performance and involve estimates, assumptions, risks, and uncertainties. Actual results, performance, or outcomes may differ materially from the results discussed in the statements. In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes to differ materially from those contained in forward-looking statements include those factors set forth in Part 1 - Item 1A - "Risk Factors" of this report and the following important factors:

- Idaho Power's rate design and the effect of regulatory decisions by the Idaho and Oregon public utilities commissions, the Federal Energy Regulatory Commission, and other regulators affecting Idaho Power's ability to recover costs and earn a return;
- changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area, the loss or change in the business of significant customers, and the availability and use of energy efficiency and conservation programs, and the associated impact on loads and load growth;
- the impacts of changes in economic conditions, including the potential for changes in customer demand for electricity, revenue from sales of excess power, financial soundness of counterparties and suppliers, and collections;
- unseasonable or severe weather conditions, wildfires, and other natural phenomena, which affect customer demand, hydroelectric generation levels, infrastructure repair costs, and the ability and cost to procure fuel for generation plants or purchased power to serve customers;
- advancement of new technologies that reduce loads or render Idaho Power's generation facilities obsolete;
- adoption of or changes in, and costs of compliance with, laws, regulations, and policies relating to the environment, natural resources, and endangered species, and the ability to recover those costs through rates;
- variable hydrological conditions and over-appropriation of surface and groundwater in the Snake River basin, which can impact the amount of generation from Idaho Power's hydroelectric facilities;
- the ability to purchase fuel and power from suppliers on favorable payment terms and prices, particularly in the event of unanticipated power demands, lack of physical availability, transportation constraints, or a credit downgrade;
- accidents, fires, explosions, and mechanical breakdowns that may occur while operating and maintaining an electric system, which can cause unplanned outages, reduce generating output, damage the companies' assets or operations, subject the companies to third-party claims for property damage, personal injury, or loss of life, or result in the imposition of civil, criminal, or regulatory fines or penalties;
- the ability to obtain debt and equity financing or refinance existing debt when necessary and on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets (including as a result of European sovereign debt issues) and interest rate fluctuations, decisions by the Idaho or Oregon public utility commissions, and the companies' past or projected financial performance;
- reductions in credit ratings, which could adversely impact access to capital markets and would require the posting of additional collateral to counterparties pursuant to existing power purchase and credit arrangements;
- the ability to buy and sell power, transmission capacity, and fuel in the markets and the availability to enter into financial and physical commodity hedges with creditworthy counterparties, including the impact of federal legislation on counterparties' willingness to transact, market liquidity, and hedging costs, which may affect fuel and power availability and pricing, and the failure of any such risk management and hedging strategies to work as intended;
- changes in or implementation of Federal Energy Regulatory Commission and other mandatory reliability, security, and other requirements for system infrastructure, which could result in penalties and increase costs;

- disruptions or outages of Idaho Power's generation or transmission systems or the western interconnected transmission system;
- the costs and operational challenges of integrating an increasing volume of mandated purchased intermittent wind power or other renewable energy sources into Idaho Power's resource portfolio;

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- further increases in the unfunded liability or changes in actuarial assumptions, the interest rate environment, and the actual return on plan assets for pension and other post-retirement plans, which can affect future funding obligations, costs, and pension and other post-retirement plan liabilities;
- the ability to continue to pay dividends under the terms of the companies' credit arrangements and regulatory limitations, and whether the companies' boards of directors will continue to declare dividends based on the boards of directors’ periodic consideration of factors affecting IDACORP's and Idaho Power's dividend policies;
- changes in tax laws or related regulations or new interpretations of applicable laws by federal, state, or local taxing jurisdictions, the availability of tax credits, and the tax rates payable by IDACORP shareholders on common stock dividends;
- employee workforce factors, including the operational and financial costs of unionization or the attempt to unionize all or part of the companies' workforce, the impact of an aging workforce, the cost and ability to retain skilled workers, and the ability to adjust the labor cost structure when necessary;
- failure to comply with state and federal laws, policies, and regulations, including new interpretations and enforcement initiatives by regulatory and oversight bodies, which may result in penalties and increase the cost of compliance, the nature and extent of investigations and audits, and costs of remediation;
- the inability to obtain, and cost of obtaining and complying with, required governmental permits and approvals, licenses, rights-of-way, and siting for transmission and generation projects and hydroelectric facilities;
- the cost and outcome of litigation, dispute resolution, regulatory proceedings, and penalties, and the ability to recover those costs or the costs of operational changes through insurance, rates, or from third parties;
- the failure of information systems or the failure to secure information system data, security breaches, or the direct or indirect effect on the companies' business resulting from the occurrence of cyber attacks, terrorist incidents, or the threat of terrorist incidents, and acts of war;
- adoption of or changes in accounting policies, principles, or estimates, including the potential adoption of all or a portion of International Financial Reporting Standards, and new Securities and Exchange Commission or New York Stock Exchange requirements, or new interpretations of existing requirements; and
- unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs, or the failure to successfully implement technology solutions.

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. IDACORP and Idaho Power disclaim any obligation to update publicly any forward-looking information, whether in response to new information, future events, or otherwise, except as required by applicable law.

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PART I
ITEM 1. BUSINESS

OVERVIEW

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

Idaho Power was incorporated under the laws of the state of Idaho in 1989 as the successor to a Maine corporation organized in 1915. Idaho Power 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. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

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 Services Co. (IESCo), which held a 99-percent limited partnership interest in IDACORP Energy L.P. (IE), a marketer of energy commodities that wound down operations in 2003. IE merged with and into IESCo effective December 31, 2012.

Idaho Power is IDACORP’s only reportable business segment, contributing substantially all of IDACORP’s net income in 2012. Segment data is presented in Note 17 – "Segment Information" to the consolidated financial statements included in this report. As of December 31, 2012, IDACORP had 2,079 full-time employees, 2,067 of whom were employed by Idaho Power, and 21 part-time employees, 20 of whom were employed by Idaho Power.

IDACORP and Idaho Power make available free of charge on their websites 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 U.S. Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the U.S. Securities and Exchange Commission (SEC). IDACORP's website is www.idacorpinc.com and can also be accessed through a link on the Idaho Power website at www.idahopower.com. The contents of the above-referenced website addresses are not part of this Annual Report on Form 10-K. Reports, proxy and information statements, and other information regarding IDACORP and Idaho Power may also be obtained directly from the SEC’s website, www.sec.gov, or from the SEC’s Public Reference Room at 100 F Street, NE, Washington, D.C. 20549.

IDACORP’s and Idaho Power’s principal executive offices are located at 1221 W. Idaho Street, Boise, Idaho 83702, and the telephone number is (208) 388-2200.

UTILITY OPERATIONS

Idaho Power’s service territory covers approximately 24,000 square miles in southern Idaho and eastern Oregon, with an estimated population of one million. Idaho Power holds franchises, typically in the form of right-of-way arrangements, 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 25 counties in Idaho and three counties in Oregon. As of December 31, 2012, Idaho Power supplied electric energy to approximately 501,000 general business customers.

Idaho Power’s principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, agriculture, forest products, beet sugar refining, and winter recreation. Idaho Power's service territory is illustrated on the following page.

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Weather, customer demand, and economic conditions impact electricity sales and costs and, therefore, Idaho Power's utility revenues are not earned and associated expenses are not incurred evenly during the year. 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. Idaho Power's retail energy sales typically peak during the summer irrigation and cooling season, with a lower peak in the winter.

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. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), and as a regulated electric utility Idaho Power is generally not subject to retail competition. Idaho Power is also under the jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. Further, the FERC has jurisdiction over, among other items, Idaho Power's transmission and wholesale sales of electricity, hydroelectric relicensing, and system reliability.

General Business Strategy

IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business. Idaho Power has a three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. Idaho Power continuously evaluates and refines its business strategy to ensure coordination among and integration of all functional areas of the company. Idaho Power's business strategy seeks to balance the interests of owners, customers, employees, and other stakeholders while maintaining the company's financial stability and flexibility. The strategy includes:

- Responsible Planning: Idaho Power's planning process is intended to ensure adequate generation and transmission resources to meet anticipated population growth and increasing electricity demand. This planning process integrates Idaho Power's regulatory strategy and financial planning, including the consideration of regional economic development in the communities Idaho Power serves.
- Responsible Development and Protection of Resources: Idaho Power's business strategy includes the development and protection of generation, transmission, distribution, and associated infrastructure, and stewardship of the natural

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resources Idaho Power and the communities it serves depend upon. Additionally, the strategy considers workforce planning and employee development and retention related to these strategic elements.

- Responsible Energy Use: Idaho Power's business strategy includes energy efficiency and demand response programs and preparation for potential carbon and renewable portfolio standards (RPS) legislation. The strategy also includes targeted reductions relating to carbon emission intensity and public reporting of these reductions.

Rates and Revenues

The prices that the IPUC and OPUC authorize Idaho Power to charge for its electric service is a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. In addition to the discussion below, see the “Regulatory Matters” section of Part II, Item 7 – “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (MD&A) and Note 3 – “Regulatory Matters” to the consolidated financial statements included in this report.

Retail Rates: Idaho Power periodically evaluates the need to seek changes to its retail electricity price structure to cover its operating costs and provide an opportunity for a reasonable rate of return. Idaho Power uses general rate cases, power cost adjustment (PCA) mechanisms, a fixed cost adjustment (FCA), balancing accounts and riders, and subject-specific filings to recover its costs of providing service and to earn a return on investment. Retail prices are determined through formal ratemaking proceedings that generally include testimony by participating parties, data requests, public hearings, and the issuance of a final order. Participants in these proceedings, which are conducted under established procedures and schedules, include Idaho Power, the staffs of the IPUC or OPUC, and other interested parties. The IPUC and OPUC are required to ensure that the prices and terms of service are fair, non-discriminatory, and provide Idaho Power an opportunity to recover its costs and earn a fair return on investment. This requirement does not, however, ensure that Idaho Power will earn a specified rate of return. In addition to general rate case filings, ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific authorization from the IPUC or OPUC. Deferred amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

Wholesale Markets: As a public utility under Part II of the Federal Power Act (FPA), Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its Open Access Transmission Tariff (OATT). Idaho Power’s OATT is revised each year based on financial and operational data Idaho Power files annually with the FERC in its Form 1. The Energy Policy Act of 2005 granted the FERC increased statutory authority to implement mandatory transmission and network reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. These mandatory transmission and reliability standards were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which has responsibility for compliance and enforcement of transmission and reliability standards.

Idaho Power participates in the wholesale energy markets by purchasing power to help meet load demands and selling power that is in excess of load demands. Idaho Power's market activities are guided by a risk management policy and frequently updated operating plans, which are influenced by customer load, market prices, generating costs, transmission constraints, and availability of generating resources. Some of Idaho Power's 17 hydroelectric generation facilities are operated to optimize the water that is available by choosing when to run hydroelectric 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. Wholesale energy market prices and compliance factors, such as allowable river stage elevation changes and flood control requirements, influence these dispatch decisions.

Energy Sales: The following table presents Idaho Power's revenues and energy use by customer type for the last three years. Approximately 95 percent of Idaho Power's general business revenue comes from customers located in Idaho, with the remainder coming from customers located in Oregon. Idaho Power's operations, including information on energy sales, are discussed further in Part II, Item 7 - "MD&A - Results of Operations - Utility Operations."

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	Year Ended December 31,		
	2012	2011	2010
Revenues (thousands of dollars)			
Residential	$431,555	$405,982	$400,607
Commercial	241,519	220,962	231,440
Industrial	145,054	140,701	138,394
Irrigation	137,424	104,635	110,555
Provision for rate refund for sharing mechanism	(7,151)	(27,099)	—
Deferred revenue related to Hells Canyon Complex relicensing AFUDC	(10,636)	(10,636)	(10,625)
Total general business revenues	937,765	834,545	870,371
Off-system sales	61,534	101,602	78,133
Other	77,426	86,581	84,548
Total revenues	$1,076,725	$1,022,728	$1,033,052
Energy use (thousands of MWh)			
Residential	5,039	5,146	4,967
Commercial	3,865	3,815	3,763
Industrial	3,133	3,100	3,076
Irrigation	2,048	1,673	1,707
Total general business	14,085	13,734	13,513
Off-system sales	2,183	3,635	1,982
Total	16,268	17,369	15,495

Power Supply

Idaho Power primarily relies on company-owned hydroelectric, coal, and gas-fired generation facilities and long-term power purchase agreements to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River basin. Market purchases and sales are used to supplement Idaho Power's generation and balance supply and demand throughout the year. Idaho Power's generating plants and their capacities are listed in Part I, Item 2 - "Properties."

Weather, load demand, and economic conditions impact power supply costs. Drought conditions and increased peak load demand cause a greater reliance on potentially more expensive energy sources to meet load requirements. Conversely, favorable hydroelectric generation conditions increase production at Idaho Power's hydroelectric generating facilities and reduce the need for thermal generation and wholesale market purchased power. Economic conditions and governmental regulations can affect the market price of natural gas and coal, which may impact fuel expense and market prices for purchased power. Idaho Power has PCA mechanisms in Idaho and Oregon that mitigate in large part the potential adverse financial statement impacts of volatile fuel and power costs.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand was 3,245 MW, set on July 12, 2012, and the all-time winter peak demand was 2,527 MW, set on December 10, 2009. During these and other similarly heavy load periods Idaho Power's system is fully committed to serve load and meet required operating reserves. The following table presents Idaho Power's total power supply for the last three years.

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	MWh			Percent of Total Generation					
	2012	2011	2010	2012		2011		2010	
	(thousands of MWh)								
Hydroelectric plants	7,956	10,937	7,344	57	%	69	%	51	%
Coal-fired plants	5,227	4,820	6,864	38	%	30	%	48	%
Natural gas fired plants	676	138	160	5	%	1	%	1	%
Total system generation	13,859	15,895	14,368	100	%	100	%	100	%
Purchased power - cogeneration and small power production	1,961	1,495	910						
Purchased power - other	1,709	1,256	1,491						
Total purchased power	3,670	2,751	2,401						
Total power supply	17,529	18,646	16,769						

Hydroelectric Generation: Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation equal to approximately 8.6 million MWh under median water conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, river base flows, spring flows, rainfall, amount and timing of water leases, and other weather and stream flow considerations. Power generation at the Idaho Power hydroelectric power plants on the Snake River also depends on the state water rights held by Idaho Power 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. Idaho Power continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at Idaho Power's hydroelectric projects on the Snake River. For more information on water management issues see Note 10 - "Contingencies" to the consolidated financial statements included in this report. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced, resulting in a reliance on other generation resources and power purchases.

Below average snow accumulation in the Snake River basin resulted in below average stream flow in 2012. As a consequence, annual generation from Idaho Power's hydroelectric facilities was 3.0 million MWh lower in 2012 than in 2011. The Northwest River Forecast Center of the National Oceanic and Atmospheric Administration reported that Brownlee Reservoir (part of the Hells Canyon Complex) inflow for April through July 2012 was 5.5 million acre-feet (maf). By comparison, April through July Brownlee Reservoir inflow was 10.5 maf in 2011 and 4.6 maf in 2010.

Idaho Power obtains licenses for its hydroelectric projects from the FERC, similar to other utilities that operate nonfederal hydroelectric projects on qualified waterways. The licensing process includes an extensive public review process and involves numerous natural resource and environmental issues. The licenses last from 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex project, its largest hydroelectric generation source. Idaho Power also has three Oregon licenses under the Oregon Hydroelectric Act, which applies to Idaho Power's Brownlee, Oxbow, and Hells Canyon facilities. For further information on relicensing activities see Part II, Item 7 – "MD&A – Regulatory Matters – Relicensing of Hydroelectric Projects."

Idaho Power is subject to the provisions of the FPA as a "public utility" and as a "licensee" by virtue of its hydroelectric operations. As a licensee under Part I of the FPA, Idaho Power and its licensed hydroelectric projects are subject to conditions described in the FPA 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.

Coal-Fired Generation: Idaho Power co-owns the following coal-fired power plants:

- Jim Bridger located in Wyoming, in which Idaho Power has a one-third interest;
- Valmy located in Nevada, in which Idaho Power has a 50 percent interest; and
- Boardman located in Oregon, in which Idaho Power has a 10 percent interest.

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Idaho Power, through its subsidiary IERCo, owns a one-third interest in BCC, which owns the Jim Bridger mine that supplies coal to the Jim Bridger power plant. PacifiCorp operates both the Jim Bridger mine and the Jim Bridger power plant. 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 from surface, high-wall, and underground sources. Idaho Power believes that the Jim Bridger mine has sufficient reserves to provide coal deliveries for at least the term of the sales agreement. Idaho Power also has a coal supply contract providing for annual deliveries of coal through 2014 from the Black Butte Coal Company’s Black Butte mine located near the Jim Bridger plant. This contract supplements the Jim Bridger mine 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 provide the opportunity to access other fuel supplies for tonnage requirements above established contract minimums.

NV Energy, Inc., as the operator of the Valmy generating plant, has agreements with coal suppliers through 2015. Idaho Power's share of these agreements along with existing coal inventory at the plant are expected to meet Idaho Power's projected coal supply needs for 2013 and 2014, and approximately 60 percent of its supply needs for 2015. As a 50-percent owner of the plant, Idaho Power is obligated to purchase one-half of the coal obtained under these contracts.

The Boardman generating plant receives coal through annual contracts with suppliers from the Powder River Basin in northeast Wyoming. Portland General Electric Company is the operator of the Boardman plant. All of the Boardman plant’s projected coal requirements in 2013 and approximately 33 percent of projected coal requirements in 2014 are under contract. A portion of the 2013 and 2014 coal purchased will be low sulfur content as Boardman prepares for the 2015 transition to a lower sulfur fuel content. As a ten percent owner of the plant, Idaho Power is obligated to purchase ten percent of the coal obtained under these agreements. In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020.

Natural Gas-fired Generation: Idaho Power owns and operates the Langley Gulch natural gas-fired combined cycle power plant and the Danskin and Bennett Mountain natural gas-fired simple cycle combustion turbine power plants. All three plants are located in Idaho. The Langley Gulch power plant was placed into service in June 2012, contributing to the notable increase in gas-fired generation during 2012 relative to prior years.

Idaho Power operates the Langley Gulch plant as a base load unit and the Danskin and Bennett Mountain plants to meet peak supply needs. The plants are also used to take advantage of wholesale market opportunities. Natural gas for all facilities is purchased based on system requirements and dispatch efficiency. The natural gas is transported through the Williams-Northwest Pipeline under Idaho Power's 55,584 million British thermal units (MMBtu) per day long-term gas transportation service agreements. These transportation agreements vary in contract length, with the latest termination date of May 2042, but with extensions at Idaho Power’s discretion. In addition to the long-term gas transportation service agreements, Idaho Power has entered into a long-term storage service agreement with Northwest Pipeline for 131,453 MMBtu of total storage capacity at the Jackson Prairie Storage Project. This firm storage contract expires in 2043. Idaho Power purchases and stores natural gas with the intent of fulfilling needs as identified for seasonal peaks or to meet system requirements.

As of December 31, 2012, approximately 3.2 million MMBtu's of natural gas was financially hedged for physical delivery for the operational dispatch of the Langley Gulch plant through December 2013. Idaho Power plans to manage the procurement of additional natural gas for the peaking units on the daily spot market or from storage inventory as necessary to meet system requirements and fueling strategies.

Purchased Power Agreements: Idaho Power purchases power in the wholesale market and pursuant to long-term power purchase contracts, as described below.

Wholesale Market Purchases: Idaho Power purchases power in the wholesale market based on economics, operating reserve margins, risk management policy limitations, and unit availability. Idaho Power seeks to manage its loads efficiently by utilizing its generation resources and long-term power purchase contracts in conjunction with buying and selling opportunities in the wholesale market. In addition to its market purchases, Idaho Power has the following notable firm wholesale power purchase contracts and energy exchange agreements:

- Raft River Energy I, LLC - for up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through April 2033.
- Telocaset Wind Power Partners, LLC - for 101 MW (nameplate generation) from its Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027.

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- USG Oregon LLC - for 22 MW (estimated average annual output) from the Neal Hot Springs #1 geothermal power plant located near Vale, Oregon. The contract term is 25 years with an option to extend. This project achieved commercial operation in November 2012.
- Clatskanie People's Utility - for the exchange of up to 18 MW of energy from the Arrowrock hydroelectric project in southern Idaho in exchange for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement is through December 31, 2015. Idaho Power has the right to renew the agreement for two additional five-year terms.

During 2012, Idaho Power purchased 1.7 million MWh of power through wholesale market purchases at an average price of $46.41 per MWh. During 2011, Idaho Power purchased 1.3 million MWh of power through wholesale market purchases at an average cost of $58.19 per MWh.

PURPA Power Purchase Contracts: Idaho Power purchases power from PURPA projects as mandated by federal law. As of December 31, 2012, Idaho Power had 779 MW nameplate capacity of PURPA-related projects on-line, with an additional 52 MW nameplate capacity of projects projected to be on-line by the end of 2014. The power purchase contracts for these projects have terms ranging from one to 35 years. The expense and volume of PURPA project power purchases during the last three years is included in the table below.

	Year Ended December 31,		
	2012	2011	2010
PURPA contract expense (in thousands)	$117,618	$90,251	$56,022
MWh purchased under PURPA contracts (in thousands)	1,961	1,495	910
Average cost per MWh from PURPA contracts	$59.98	$60.36	$61.56

The bulk of the increase in volume of PURPA power purchases resulted from additional wind projects. Pursuant to the requirements of Section 210 of PURPA, the state regulatory commissions having jurisdiction over Idaho Power have each issued orders and rules regulating Idaho Power's purchase of power from "qualifying facilities" that meet the requirements of PURPA. A key component of the PURPA contracts is the energy price contained within the agreements. PURPA regulations specify that a utility must pay energy prices based on the utility's avoided costs. The IPUC and OPUC have established specific rules and regulations to calculate the avoided cost that Idaho Power is required to include in PURPA contracts. For PURPA power purchase agreements:

- Idaho Power is required to purchase all of the output from the facilities located inside its service territory, subject to some exceptions such as adverse impacts on system reliability.
- Idaho Power is required to purchase the output of projects located outside its service territory if it has the ability to receive power at the facility's requested point of delivery on Idaho Power's system.
- The IPUC jurisdictional portion of the costs associated with PURPA contracts is fully recovered through base rates and the PCA, and the OPUC jurisdictional portion is recovered through general rate case filings and an Oregon PCA mechanism.
- IPUC and OPUC jurisdictional regulations allow PURPA standard contract terms to be up to 20 years.
- The IPUC requires Idaho Power to pay "published avoided cost" rates for all wind and solar projects that are smaller than 100 kW and all other types of projects that are smaller than 10 average MWs. For PURPA qualifying facilities that exceed these size limitations, Idaho Power is required to negotiate an applicable price (premised on avoided costs) based upon IPUC regulations.
- The OPUC requires that Idaho Power pay the published avoided costs for all PURPA qualifying facilities with a nameplate rating of 10 MW or less and that Idaho Power negotiate an applicable price (premised on avoided costs) for all other qualifying facilities based upon OPUC regulations.

Idaho Power, as well as other power utilities with an Idaho service territory, has been engaged in proceedings at the IPUC and OPUC relating to PURPA contract terms, including the prices paid for energy purchased from PURPA projects. Refer to "MD&A - Regulatory Matters - Renewable Energy Contracts, Renewable Energy Certificates, and Emission Allowances" for a summary of those proceedings.

Transmission Services

Electric transmission systems deliver energy from electric generation facilities to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generation facilities can be

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located anywhere from a few miles to hundreds of miles from customers. Idaho Power's generating facilities are interconnected through its integrated transmission system and are operated on a coordinated basis to achieve maximum capability and reliability. Idaho Power's transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration, Avista Corporation, PacifiCorp, NorthWestern Energy, and NV Energy, Inc. These interconnections, coupled with transmission line capacity made available under agreements with some of those entities, permit the interchange, purchase, and sale of power among entities in the Western Interconnection. Idaho Power provides wholesale transmission service and provides firm and non-firm wheeling services for eligible transmission customers. Idaho Power is a member of the Western Electricity Coordinating Council, the Northwest Power Pool, the Northern Tier Transmission Group, and the North American Energy Standards Board. These groups have been formed to more efficiently coordinate transmission reliability and planning throughout the Western Interconnection.

Resource Planning

Integrated Resource Plan: The IPUC and OPUC require that Idaho Power biennially prepare an Integrated Resource Plan (IRP). Idaho Power filed its 2011 IRP with the IPUC and OPUC in June 2011. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side and demand-side resource options, and identifies potential near-term and long-term actions. The 2011 IRP was accepted by the IPUC in December 2011 and acknowledged by the OPUC in February 2012. The four primary goals of the IRP are to:

- identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period;
- ensure the selected resource portfolio balances cost, risk, and environmental concerns;
- give equal and balanced treatment to both supply-side resources and demand-side measures; and
- involve the public in the planning process in a meaningful way.

Idaho Power updates the IRP every two years and preparation of the 2013 IRP is in process. Idaho Power expects that the 2013 IRP will be completed and filed in June 2013. During the time between resource plan filings, the public and regulatory oversight of the activities identified in the 2011 IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power makes periodic adjustments and corrections to the resource plan to reflect changes in technology, economic conditions, anticipated resource development, and regulatory requirements.

The 2011 IRP included as new generation resources the 318-MW Langley Gulch natural-gas fired power plant, which came on-line in June 2012, and a 49-MW expansion of the Shoshone Falls hydroelectric facility, which is under evaluation and unlikely to be constructed prior to 2019. The 2011 IRP also identified the Boardman-to-Hemingway transmission line in the preferred resource portfolio. Idaho Power believes the Boardman-to-Hemingway transmission line and the existing Hemingway substation, together with the Gateway West transmission line, will improve reliability, relieve transmission congestion, and provide system flexibility. Additional information about Idaho Power's significant infrastructure development projects is included in Item 7 - "MD&A - Liquidity and Capital Resources - Capital Requirements - Major Infrastructure Projects."

Preliminary work performed in connection with Idaho Power's 2013 IRP indicates more moderate load growth rates in Idaho Power's service area than what was forecast in the 2011 IRP. The moderation in load growth is in large part the result of changes in expectations surrounding economic conditions, anticipated electricity price increases incorporating impacts of carbon legislation, loss of anticipated load from the Hoku Materials, Inc. special customer contract, and the elimination of an anticipated but unidentified special contract customer that had been included in the 2011 IRP. The 2013 IRP median annual average load forecast projects growth of 1.1 percent annually over the next 20 years, whereas the 2011 IRP included a forecast growth rate of 1.4 percent. For median peak-hour load, the 2013 IRP is expected to project an annual average growth rate of 1.4 percent whereas the 2011 IRP included a forecast growth rate of 1.8 percent. Accounting for the reduced load growth and excluding approximately 400 MW of demand response programs, the preliminary 2013 IRP load and resource balance forecasts the first resource capacity deficit will not occur until the summer of 2016 under one scenario. Although the 2013 IRP is projected to forecast lower load growth rates, there is still much uncertainty regarding the rate of recovery from the recession and the subsequent impact on Idaho Power's future load growth. Idaho Power expects to be able to manage any near-term summer peak capacity deficits until completion of the Boardman-to-Hemingway transmission line, which is expected in 2018 at the earliest. If the Boardman-to-Hemingway line is not constructed by the time necessary to meet load demands, Idaho Power will need to identify alternatives to meet load requirements.

In response to the operational challenges associated with integrating intermittent wind power that Idaho Power must purchase pursuant to PURPA, and the recognition that the costs and challenges associated with integrating intermittent resources will become even more pronounced as the volume of intermittent resources in Idaho Power's portfolio increases, Idaho Power

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continues efforts to better understand the effects of wind generation on power system operation. As part of these efforts, Idaho Power issued its first wind integration study in 2007, and in late 2012 completed a second, more comprehensive wind integration study. The goal of the most recent study was to assess the additional costs incurred in modifying operations of Idaho Power's dispatchable generating resources to compensate for the variable and intermittent energy supplied by wind generators while maintaining reliable energy delivery to customers. Additionally, the study aimed to provide insight on the maximum amount of wind generation Idaho Power's system can accommodate without impacting reliability. Idaho Power has committed considerable resources to the study, including working with an independent consultant, utility industry peers, and interested parties, and has held public workshops. Idaho Power released the report publicly in February 2013 as part of its 2011 IRP update. In further response to the integration challenges, Idaho Power has implemented an internally developed wind forecasting system, in recognition that cost-intensive modifications to operations intended to integrate wind are reduced, though not eliminated, with improved wind production forecasting.

On or before January 1, 2020, Idaho Power is required to own or contract to purchase the capacity and output from a qualifying solar photovoltaic (PV) system with a minimum capacity of 500 kW pursuant to the state of Oregon's solar PV capacity standard. The timing of development of this required project in Oregon and the solar demonstration project referenced in Idaho Power's 2011 IRP will depend in large part on Idaho Power's ability to resolve integration, reliability, and cost issues associated with the recent influx of PURPA resources from which Idaho Power is currently mandated to purchase power. However, with the cost of solar PV technology continuing to decrease, Idaho Power believes this technology will become more prevalent in its service area over the long term. Idaho Power continues to evaluate the timing for proceeding with solar PV technology.

Energy Efficiency and Demand Response Programs: Idaho Power has 18 energy efficiency and demand response programs targeting energy savings across the entire year and summer system demand reduction. These programs are offered to all customer segments and emphasize the wise use of energy, especially during periods of high demand. This energy and demand reduction can minimize or delay the need for new infrastructure. Idaho Power’s programs include:

- financial incentives for irrigation customers for either improving the energy efficiency of an irrigation system or installing new energy efficient systems;
- energy efficiency for new and existing homes, including efficient appliances and HVAC equipment, energy efficient building techniques, insulation improvement, air duct sealing, and energy efficient lighting;
- incentives to industrial and commercial customers for acquiring energy efficient equipment, and using energy efficiency techniques for operational and management processes; and
- demand response programs to reduce peak summer demand through the voluntary interruption of central air conditioners for residential customers, interruption of irrigation pumps, and reduction of commercial and industrial demand through a third-party demand response aggregator.

In 2012, Idaho Power’s energy efficiency programs reduced energy usage by approximately 157,000 MWh. Idaho Power's demand response programs had available capacity of approximately 411 MW; however, because of a relatively high cost to dispatch Idaho Power's Irrigation Peak Rewards program it was not used in 2012. Idaho Power realized approximately 91 MW in summer peak demand reduction through the A/C Cool Credit and the FlexPeak Management programs as these programs have no marginal dispatch costs. In December 2012, Idaho Power filed with the IPUC to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs for the summer of 2013 in order to work with stakeholders and IPUC Staff to explore the near-term need for and design of the demand response programs. A settlement stipulation relating to temporary suspension of the programs is pending before the IPUC.

In 2012, Idaho Power spent approximately $49.3 million on energy efficiency and targeted demand reduction response programs. Approximately $27.1 million annually of funding for these programs is provided by Idaho and Oregon energy efficiency tariff riders, while the balance of the funding comes from Idaho Power base rates and the PCA mechanism. In 2012, as approved by the IPUC, Idaho Power capitalized approximately $6 million of custom efficiency program incentives as a regulatory asset. For expenditures in 2012, Idaho Power will also recover approximately $14.5 million in demand response incentives through its annual PCA as approved by the IPUC.

Approximately $4.7 million of Idaho Power's 2012 energy efficiency spending was related to research and analysis, education, technology evaluation, and market transformation. Most of this activity was done in conjunction with the Northwest Energy Efficiency Alliance.

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Environmental Regulation and Costs

Idaho Power'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 Idaho Power's operations due to the cost of installation and operation of equipment and facilities required for compliance with environmental regulations, and the modification of system operations to accommodate environmental regulations. In addition to generally applicable regulations, the FERC licenses issued for Idaho Power's hydroelectric generating plants have environmental requirements such as aeration of turbine water to meet dissolved gas and temperature standards in the tail waters downstream from the plants. Idaho Power monitors these issues and reports the results to the appropriate regulatory agencies. Idaho Power's three coal-fired power plants and three natural gas combustion turbine power plants are also subject to a broad range of environmental requirements, including air quality regulation. For a more detailed discussion of these and other environmental issues, refer to Item 7 – "MD&A – Environmental Matters" in this report.

Cost Estimates: Idaho Power's environmental compliance expenditures will continue to be significant for the foreseeable future, especially with potential additional regulation under discussion at the federal level. Idaho Power estimates its environmental expenditures, based upon present environmental laws and regulations, will be as follows for the periods indicated, excluding allowance for funds used during construction (AFUDC) (in millions of dollars):

Environmental Expenditures	2013	2014 - 2015
Capital expenditures:		
Studies and measures at hydroelectric facilities	$12	$41
Investments in equipment and facilities at thermal plants	50	94
Total capital expenditures	$62	$135
Operating expenses:		
Operating costs for environmental facilities - hydroelectric	$21	$49
Operating costs for environmental facilities - thermal	8	22
Total operations and maintenance	$29	$71

Idaho Power anticipates that a number of new and impending EPA rulemakings and proceedings addressing, among other things, ozone and fine particulate matter pollution, emissions, and disposal of coal combustion residuals could result in substantially increased operating and compliance costs in addition to the amounts set forth above, but Idaho Power is unable to estimate those costs given the uncertainty associated with pending regulations.

Environmental Controls Cost Study: In connection with its IRP process, Idaho Power has been conducting cost studies and scenario analyses to assess the potential future investments necessary for the continued operation of the Jim Bridger and Valmy coal-fired generation facilities. The Boardman plant was not included in the study because of the existing schedule to cease coal-fired operations at that plant by the end of 2020. Some of the future environmental control requirements for the Jim Bridger and Valmy plants are known; however, additional requirements could arise from future regulations. In the analysis, the cost of future compliance was compared to the cost of replacement generation capacity provided by combined-cycle combustion turbine technology and conversion of the units to natural gas. Because of the speculative nature of many of the future requirements, the analysis was performed under a range of fuel pricing assumptions, carbon cost assumptions, plant upgrade and retirement costs, environmental regulation assumptions, and replacement costs. Idaho Power published the results of the study with its 2011 IRP update filed with the IPUC and OPUC in February 2013. Idaho Power concluded in its study that the Jim Bridger and Valmy plants should be retained in its resource portfolio and supports planned investments in environmental controls at those plants. This is particularly true in light of the desire to maintain a diversified portfolio of generation assets and fuel diversity that can mitigate risk associated with increases in natural gas prices. However, the study also concluded that in the event significant additional operating and maintenance or capital expenditures are necessary at the Valmy plant as a result of new environmental requirements, Idaho Power will conduct a further review to determine whether such investments are economically appropriate, and whether conversion of the facility to a natural-gas fired plant would be appropriate.

Inaugural Sustainability Report: In May 2012, IDACORP publicly issued its inaugural sustainability report. The sustainability report highlights Idaho Power's continuing efforts to operate in a manner that supports financial, environmental, and social stewardship. IDACORP plans to issue its second sustainability report in May 2013 and make it available on its or Idaho Power's website.

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Extension of Idaho Power's Voluntary CO_2 Intensity Reduction Goal: While there is currently no national mandatory greenhouse gas reduction requirement, Idaho Power continues to prepare for potential legislative and/or regulatory restrictions on emissions in order to help reduce the costs of complying with such restrictions on its customers. To that end, Idaho Power is engaged in voluntary greenhouse gas emission intensity reduction efforts. In September 2009, IDACORP's and Idaho Power's boards of directors approved guidelines that established a goal to reduce Idaho Power's resource portfolio's average carbon dioxide (CO_2) emission intensity for the 2010 through 2013 time period to a level of 10 to 15 percent below Idaho Power's 2005 CO_2 emission intensity of 1,194 lbs CO_2/MWh. Idaho Power's estimated CO_2 emission intensity from its generation facilities, as submitted to the Carbon Disclosure Project, was 672, 1,051, and 1,004 lbs/MWh for 2011, 2010, and 2009 respectively. As of the date of this report, Idaho Power is on track to exceed the CO_2 emission intensity reduction goal it established in 2009. The combination of effective utilization of hydroelectric projects, above average stream flows, reduced usage of coal-fired facilities, and addition of the Langley Gulch natural gas-fired power plant have positioned Idaho Power to extend its CO_2 intensity reduction goal period for an additional two years, targeting an average reduction of 10 to 15 percent below its 2005 levels for the entire 2010 through 2015 time period.

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 $5.5 million, $6.4 million, and $7.3 million in 2012, 2011, and 2010, respectively. IFS's portfolio also includes historic rehabilitation projects such as the Empire Building in Boise, Idaho. IFS made no new investments in 2012 or 2011, but did have $7 million of new investments during 2010.

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, 2012, the gross amount of IFS's portfolio equaled $195 million in tax credit investments. These investments cover 49 states, Puerto Rico, and the U.S. Virgin Islands. The underlying investments include approximately 570 individual properties, of which all but four are administered through syndicated funds.

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. Idaho Power purchased all of the power generated by Ida-West's four Idaho hydroelectric projects at a cost of $9 million, $9 million, and $8 million in 2012, 2011, and 2010, respectively.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages, and positions of the executive officers of IDACORP and Idaho Power are listed below, along with their business experience during at least 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 appointed.

Senior Executive Officers (in alphabetical order)

DARREL T. ANDERSON, 54

- President and Chief Financial Officer of Idaho Power Company, January 1, 2012 - present.
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- Executive Vice President, Administrative Services and Chief Financial Officer of IDACORP, Inc., October 1, 2009 - present.
- Executive Vice President, Administrative Services and Chief Financial Officer of Idaho Power Company, October 1, 2009 - December 31, 2011.
- Senior Vice President - Administrative Services and Chief Financial Officer of IDACORP, Inc. and Idaho Power Company, July 1, 2004 - September 30, 2009.

REX BLACKBURN, 57

- Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power Company, April 1, 2009 - present.
- Senior Attorney, Idaho Power Company, January 1, 2008 - March 31, 2009.

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LISA A. GROW, 47
• Senior Vice President, Power Supply of Idaho Power Company, October 1, 2009 - present.
• Vice President - Delivery Engineering and Operations of Idaho Power Company, July 20, 2005 - September 30, 2009.

J. LAMONT KEEN, 60
• President and Chief Executive Officer of IDACORP, Inc., July 1, 2006 - present.
• Chief Executive Officer of Idaho Power Company, November 17, 2005 - present.
• President of Idaho Power Company, March 1, 2002 - December 31, 2011.
• Member of the Boards of Directors of both IDACORP, Inc. and Idaho Power Company.

STEVEN R. KEEN, 52
• Senior Vice President, Finance and Treasurer of Idaho Power Company, January 1, 2012 - present.
• Vice President, Finance and Treasurer of IDACORP, Inc., June 1, 2010 - present.
• Vice President, Finance and Treasurer of Idaho Power Company, June 1, 2010 - December 31, 2011.
• Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, June 1, 2006 - May 31, 2010.

DANIEL B. MINOR, 55
• Executive Vice President and Chief Operating Officer of Idaho Power Company, January 1, 2012 - present.
• Executive Vice President of IDACORP, Inc., May 20, 2010 - present.
• Executive Vice President, Operations of Idaho Power Company, October 1, 2009 - December 31, 2011.
• Senior Vice President - Delivery of Idaho Power Company, July 1, 2004 - September 30, 2009.

Other Executive Officers (in alphabetical order)

DENNIS C. GRIBBLE, 60
• Vice President and Chief Information Officer of Idaho Power Company, June 1, 2006 - present.
• Vice President and Chief Information Officer of IDACORP, Inc., June 1, 2006 - December 31, 2011.

PATRICK A. HARRINGTON, 52
• Corporate Secretary of IDACORP, Inc. and Idaho Power Company, March 15, 2007 - present.

WARREN KLINE, 57
• Vice President, Customer Operations of Idaho Power Company, May 20, 2010 - present.
• Vice President - Customer Service and Regional Operations of Idaho Power Company, July 20, 2005 - May 19, 2010.

JEFFREY MALMEN, 45
• Vice President, Public Affairs of IDACORP, Inc. and Idaho Power Company, October 1, 2008 - present.
• Senior Manager - Governmental Affairs of IDACORP, Inc. and Idaho Power Company, December 10, 2007 - September 30, 2008.

LUCI K. MCDONALD, 55
• Vice President, Human Resources and Corporate Services of Idaho Power Company, May 20, 2010 - present
• Vice President, Human Resources and Corporate Services of IDACORP, Inc., May 20, 2010 - December 31, 2011.
• Vice President - Human Resources of IDACORP, Inc. and Idaho Power Company, December 6, 2004 - May 19, 2010.

KEN W. PETERSEN, 49
• Corporate Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
• Corporate Controller of IDACORP and Idaho Power Company, December 29, 2007 - May 19, 2010.

N. VERN PORTER, 53
- Vice President, Delivery Engineering and Construction, Idaho Power Company, May 17, 2012 - present.
- Vice President, Delivery Engineering and Operations, Idaho Power Company, October 1, 2009 - May 16, 2012.
- General Manager of Power Production of Idaho Power Company, April 22, 2006 - September 30, 2009.

GREGORY W. SAID, 58
- Vice President, Regulatory Affairs, Idaho Power Company, January 20, 2011 - present.
- General Manager of Regulatory Affairs, Idaho Power Company, April 3, 2010 - January 19, 2011.

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- Director, State Regulation, Idaho Power Company, August 23, 2008 - April 2, 2010.
- Manager, Revenue Requirement, Idaho Power Company, November 14, 1998 - August 22, 2008.

NAOMI SHANKEL, 41
- Vice President, Supply Chain of Idaho Power Company, May 20, 2010 - present.
- Vice President, Supply Chain of IDACORP, Inc., May 20, 2010 - December 31, 2011.
- Vice President, Audit and Compliance of IDACORP, Inc. and Idaho Power Company, September 21, 2006 - May 19, 2010.

LORI D. SMITH, 52
- Vice President, Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
- Vice President - Corporate Planning and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, January 1, 2008 - May 19, 2010.

ITEM 1A. RISK FACTORS

The circumstances and factors set forth below may have a material impact on the business, financial condition, or results of operations of IDACORP and Idaho Power and could cause actual results or outcomes to differ materially from those discussed in any forward-looking statements.

If the Idaho Public Utilities Commission, the Oregon Public Utility Commission, or the Federal Energy Regulatory Commission grant less rate recovery in regulatory proceedings than Idaho Power needs to cover existing and future costs and earn an acceptable rate of return, IDACORP's and Idaho Power's financial condition and results of operations may be adversely affected. The prices that the Idaho Public Utilities Commission and Oregon Public Utility Commission authorize Idaho Power to charge for its retail services, and the tariff rate that the Federal Energy Regulatory Commission permits Idaho Power to charge for its transmission services, are generally the most significant factors influencing IDACORP's and Idaho Power's business, results of operations, and financial condition. The Idaho Public Utilities Commission and Oregon Public Utility Commission have the authority to disallow recovery of any costs that they consider unreasonable or imprudently incurred. Also, the rates allowed by the Federal Energy Regulatory Commission for transmission service may be insufficient for recovery of costs incurred. The regulatory process does not assure that Idaho Power will be able to achieve the rate of return allowed by the Idaho and Oregon public utility commissions. Further, while the Idaho Public Utilities Commission and Oregon Public Utility Commission are required to establish rates that are fair, just, and reasonable, they have considerable discretion in applying this standard. The ratemaking process typically involves multiple parties, including governmental bodies, consumer advocacy groups, and customers. While each party has differing concerns, they often have the common objective of limiting rate increases or even reducing rates.

Idaho Power cannot predict the outcome of ratemaking proceedings, including what rates of return will be authorized, the extent to which costs will be allowed for recovery, or the timing of recovery. The failure of Idaho Power to obtain approvals from regulatory authorities to recover costs, construct new generating or transmission facilities, install environmental emission control equipment, or otherwise operate Idaho Power's business may adversely impact Idaho Power's ability to achieve its strategic plan, cause IDACORP and Idaho Power to record an impairment of their assets, and have a material adverse impact on their results of operations and financial condition. In a number of proceedings in recent years, Idaho Power has been denied recovery, or deferred recovery pending the next general rate case, including denials or deferrals related to compensation expenses and construction expenditures. For additional information relating to Idaho Power's regulatory framework and recent matters, see Item 1 - "Business - Utility Operations," Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, and Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Regulatory Matters" in this report.

Idaho Power's cost recovery deferral mechanisms may not function as intended, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power has power cost adjustment mechanisms in its Idaho and Oregon jurisdictions and a fixed cost adjustment mechanism in Idaho that provide for periodic adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms track Idaho Power’s actual net power supply costs (primarily fuel and purchased power less off-system sales) and compares these amounts to net power supply costs being recovered in retail rates. A majority, but not all, of the variance between these two amounts is deferred for future recovery from, or refund to, customers through rates. Consequently, the power cost adjustment mechanisms only partially offset the potentially adverse financial impacts of forced generating plant outages, severe weather, reduced hydroelectric generation, and volatile wholesale energy prices. Because of the power cost adjustment mechanisms, the primary financial impact of power

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supply cost variations is on the timing of cash flows. When costs rise above the level recovered in current retail rates it adversely affects Idaho Power’s operating cash flow and liquidity until those costs are recovered from customers.

Unanticipated changes in loads in Idaho Power’s service territory expose Idaho Power to market and operational risk and could increase costs and adversely affect IDACORP's and Idaho Power's results of operations and financial condition. While Idaho Power’s customer growth rate has slowed in recent years, Idaho Power believes its service territory is an attractive one for both businesses and individuals. Idaho Power has recently adjusted its load forecast as part of its integrated resource planning process, predicting a lower growth rate over its 20-year resource planning horizon compared to prior estimates. In its efforts to balance loads and resources, Idaho Power makes load estimates that are based on a number of factors that are uncertain and difficult to estimate, and any unanticipated increase in the demand for energy could result in increased reliance on purchased power to meet peak system demand, the need to reinstate or initiate new demand response and energy efficiency programs, or the need for investment in additional generation resources. If the incremental costs associated with the unanticipated changes in loads exceed the incremental revenue and Idaho Power is unable to secure timely rate relief to recover those costs, the resulting disconnect between the time costs are incurred or investments are made and the time costs are recovered could have an adverse effect on IDACORP's or Idaho Power's financial condition and results of operations.

National and regional economic conditions may reduce customer growth rates, reduce energy consumption, or cause increased late payments and uncollectible customer accounts, which would adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Beginning in 2008, economic conditions in Idaho Power’s service area have been relatively weak. Weak economic conditions may reduce the amount of energy Idaho Power’s customers consume, result in a loss of customers (including large-load industrial and commercial customers) or further decrease the customer growth rate, and increase the likelihood and prevalence of late payments and uncollectible accounts. A resulting decrease in overall customer usage or collections and load growth at a rate less than anticipated may alter capital spending plans and rate base growth and may reduce revenues, earnings, and cash flows. Also, Idaho Power's regulatory mechanisms, including its load change adjustment rate and fixed cost adjustment mechanism in Idaho, are unlikely to result in Idaho Power recovering all of its costs related to load decreases, which would have a negative impact on IDACORP's and Idaho Power's financial condition and results of operations.

Extreme weather events and their associated impacts, such as high winds and fires, whether as a result of climate change or otherwise, can adversely affect IDACORP's and Idaho Power's results of operations and financial condition. Extreme weather events can damage generation facilities and disrupt transmission and distribution systems, causing service interruptions and extended outages, increasing supply chain costs, and limiting Idaho Power's ability to meet customer energy demand. Disruption in generation, transmission, and distribution systems due to weather-related factors also increases operations and maintenance expenses and could negatively affect IDACORP's and Idaho Power's results of operation and financial condition.

New advances in power generation, energy efficiency, or other technologies that impact the power utility industry could cause an erosion in revenues. With the escalating costs of energy has come the incentive for the development of new technologies for power generation and energy efficiency, and an investment in research and development to make those technologies more efficient and cost-effective. For instance, while solar technology remains a relatively high-cost means of power generation, there have been numerous recent advancements in the design of solar generation facilities and the materials used in panels (for example, copper indium gallium diselenide and amorphous silicon). These advancements may further increase the efficiency and power output of solar generation sources. Considerable emphasis has also been placed on energy efficiency and products that reduce electricity usage, such as LED lighting. There is potential that power generation systems provided by third parties, whether solar generation or otherwise, and energy efficiency measures could become sufficiently cost-effective and efficient that customers choose to install such systems on their homes or businesses. This may render traditional generation sources owned by Idaho Power obsolete or decrease the need for energy supplied by Idaho Power, which would reduce Idaho Power's revenue and have a negative impact on IDACORP's and Idaho Power's results of operations and financial condition.

Capital expenditures for power generation and delivery infrastructure and replacement of that infrastructure, and the timing and availability of cost recovery for those expenditures, can significantly affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power’s business is capital intensive and requires significant investments in energy generation, transmission, and distribution infrastructure. Long-term increases in both the number of customers and the demand for energy require expansion and reinforcement of that infrastructure. For instance, Idaho Power is in the permitting process for two 500-kV transmission line projects. Construction projects are subject to usual construction risks that can adversely affect project costs and completion time. These risks include the ability to obtain labor or materials; increases in cost of labor and materials; contractor defaults; equipment, engineering, and design failures; adverse weather conditions; lack of availability of financing; the ability to obtain and comply with permits and land use rights; environmental constraints;

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disputes and litigation with third parties; and changes in applicable laws or regulations. If Idaho Power is unable to complete the construction of a project, or incurs costs that regulators do not deem prudent, it may not be able to recover its costs in full through rates. Even if Idaho Power completes a construction project, the total costs may be higher than estimated and/or higher than amounts approved for recovery by regulators. If Idaho Power does not receive timely regulatory recovery of costs associated with those expansion and reinforcement activities, Idaho Power will have to rely more heavily on external debt or equity financing for its future capital expenditures. These large capital expenditures may weaken the consolidated financial profile of IDACORP and Idaho Power. Additionally, a significant portion of Idaho Power’s facilities were constructed many years ago, which could affect reliability, increase repair and maintenance expenses, and increase reliance on market purchases of power, which may negatively affect IDACORP's and Idaho Power's financial condition and results of operations.

Further, if Idaho Power were unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads, such as the Boardman-to-Hemingway transmission line, it may terminate those projects and, as an alternative, develop additional generation facilities within areas where Idaho Power has available transmission capacity or pursue other more costly options to serve loads. Termination of a project carries with it the potential for a write-off of all or a significant portion of the costs associated with the project if state public utility commissions deny recovery of costs they deem imprudently incurred, which could negatively affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power’s business is subject to an extensive set of environmental laws, rules, and regulations, which could impact Idaho Power's operations and increase costs of operations, potentially rendering some generating units uneconomical to maintain or operate, and could increase the costs and alter the timing of major projects. A number of federal, state, and local environmental statutes, rules, and regulations relating to air quality, water quality, natural resources, and health and safety are applicable to Idaho Power's operations. These laws and regulations generally require Idaho Power to obtain and comply with a wide variety of environmental licenses, permits, inspections, and other approvals, and may be enforced by both public officials and private individuals. Some of these regulations are changing or subject to interpretation, and failure to comply may result in penalties or other adverse consequences. Environmental regulations have created the need for Idaho Power to install new pollution control equipment at, and may cause Idaho Power to perform environmental remediation on, its owned or co-owned facilities, often at a substantial cost. For instance, Idaho Power plans to install environmental control apparatus at its co-owned Jim Bridger power plant in 2015 and 2016 at a cost of approximately $120 million, and a second set of control apparatus in 2021 and 2022. Idaho Power expects that there will be other costs relating to environmental regulations, and those costs are likely to be substantial. Idaho Power is not guaranteed recovery of those costs. For instance, in December 2012 the Oregon Public Utility Commission disallowed in part cost recovery for certain environmental upgrades made to a coal plant by one of Idaho Power's Northwest region peer utilities, citing an insufficient cost analysis. If Idaho Power is similarly unable to recover in full its costs through the ratemaking process, such non-recovery would negatively impact IDACORP's and Idaho Power's financial condition and results of operations.

Moreover, there are many legislative and rulemaking initiatives pending at the federal and state level that are aimed at the reduction of fossil fuel plant emissions. Idaho Power cannot predict the outcome of pending or future legislative and rulemaking proposals, or the compliance costs Idaho Power would incur in connection with that legislation. Future changes in environmental laws or regulations governing emissions reduction may make certain electric generating units (especially coal-fired units) uneconomical and subject to shut-down, may require the adoption of new methodologies or technologies that significantly increase costs or delay in-service dates, and may raise uncertainty about the future viability of fossil fuels as an energy source for new and existing electric generation facilities. Furthermore, Idaho Power may not be able to obtain or maintain all environmental regulatory approvals necessary for operation of its facilities and execution of its long-term strategy, including construction of new transmission and distribution infrastructure. If there is a delay in obtaining any required environmental regulatory approval or if Idaho Power fails to obtain, maintain, or comply with any such approval, construction and/or operation of Idaho Power's generation or transmission facilities could be delayed, halted, or subjected to additional costs. At the same time, consumer preference for renewable or low greenhouse gas-emitting sources of energy could impact the desirability of generation from existing sources and require significant investment in new generation and transmission resources.

Relicensing of the Hells Canyon hydroelectric project and construction of the proposed Gateway West and Boardman-to-Hemingway transmission lines requires consultation under the Endangered Species Act to determine the effects of these projects on any listed species within the project areas. The listing of species as threatened or endangered will result in a costly Endangered Species Act consultation for the two transmission projects and for any future transmission projects. Similarly, the presence of sage grouse in the vicinity of the Gateway West and Boardman-to-Hemingway transmission projects has required more extensive, costly, and time consuming evaluation and engineering. These and other requirements of the Endangered

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Species Act, Clean Air Act, Clean Water Act, and similar environmental laws may increase costs, the timing or ability to complete major projects, and reduce earnings and cash flows.

Factors contributing to lower hydroelectric generation can increase costs and negatively impact IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power derives a significant portion of its power supply from its hydroelectric facilities. Because of Idaho Power’s heavy reliance on hydroelectric generation, snowpack, the timing of run-off, and the availability of water in the Snake River basin can significantly affect its operations. The combination of declining Snake River base flows, over-appropriation of water, and periods of drought have led to water rights disputes and proceedings among surface water and ground water irrigators and the State of Idaho. Recharging the Eastern Snake Plain aquifer by diverting surface water to porous locations and permitting it to sink into the aquifer is one proposed solution to the over-appropriation dispute. Diversions from the Snake River for aquifer recharge or the loss of water rights may further reduce Snake River flows available for hydroelectric generation. When hydroelectric generation is reduced, Idaho Power must increase its use of more expensive thermal generating resources and purchased power; therefore, costs increase and opportunities for off-system sales are reduced, reducing earnings. Through its power cost adjustment mechanisms, Idaho Power expects to recover most of the increase in net power supply costs caused by lower hydroelectric generation. Recovery of the increased costs, however, may not occur until the subsequent power cost adjustment year, negatively affecting cash flows and liquidity.

Conditions imposed in connection with hydroelectric license renewals may require large capital expenditures, increase operating costs, reduce hydroelectric generation, and negatively affect IDACORP's or Idaho Power's results of operations and financial condition. For the last several years, Idaho Power has been engaged in an effort to renew its federal license for its largest hydroelectric generation source, the Hells Canyon Complex. Relicensing includes an extensive public review process that involves numerous natural resource issues and environmental conditions. The listing of various species of marine life, wildlife, and plants as threatened or endangered has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. In particular, fish and other marine life recovery plans may require major operational changes to the region’s hydroelectric projects. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to hydroelectric facilities, which could further increase required expenditures for marine life recovery and endangered species protection and reduce the amount of hydroelectric generation available to meet Idaho Power’s energy requirements.

In 2007, the Federal Energy Regulatory Commission Staff issued a final environmental impact statement for the Hells Canyon Complex, which the Federal Energy Regulatory Commission will use in part to determine whether, and under what conditions, to issue a new license for the Hells Canyon Complex. Certain portions of the final environmental impact statement involve issues that may be influenced by water quality certifications for the project under Section 401 of the Clean Water Act and formal consultations under the Endangered Species Act, which remain unresolved. One significant issue involves water temperature gradients, and certain parties in the relicensing proceedings have advocated for the installation of water temperature management apparatus which, if required to be installed, would require substantial capital expenditures to construct and maintain. Idaho Power may be unable to recover in full the costs of such an apparatus through rates, particularly given the magnitude of any potential impact on customer rates. Idaho Power also cannot predict the requirements that might be imposed during the relicensing process, the financial impact of those requirements, or whether a new multi-year license will ultimately be issued. Imposition of onerous conditions in the relicensing process could result in Idaho Power incurring significant capital expenditures, increase operating costs, and reduce hydroelectric generation, which could negatively affect results of operations and financial condition.

IDACORP's and Idaho Power's operating results are subject to seasonal fluctuations, and unusually mild temperatures can impact their results of operations and financial condition. Electric power sales are generally seasonal, with demand in Idaho Power's service territory peaking during the hot summer months, with a secondary peak during the cold winter months. The loads required by irrigation customers in Idaho Power's service territory can also create significant seasonal changes in usage. When temperatures are relatively mild, loads are often lower as customers are not using electricity for heating and air conditioning purposes. Thus, unusually mild weather or the timing and extent of precipitation in the future could adversely impact IDACORP's and Idaho Power's results of operations and financial condition.

Complying with state or federal renewable portfolio standards could increase capital expenditures and operating costs and adversely affect IDACORP's and Idaho Power's results of operations and financial condition. A number of states have adopted renewable portfolio standards, which require that electricity providers obtain a minimum percentage of their power from renewable energy sources by a specified date. Idaho Power’s operations in Oregon will be required to comply with a ten percent renewable portfolio standard beginning in 2025, and it is possible that other states, including Idaho, could adopt renewable portfolio standards. The cost of purchasing or generating power from renewable energy sources is often greater than fossil fuel and hydroelectric generation sources, and construction of renewable energy facilities involves significant capital expenditures. As a result, new state or federal renewable portfolio standards could increase capital expenditures and operating costs and negatively affect results of operations and financial condition.

Idaho Power’s reliance on coal and natural gas to fuel its non-hydroelectric power generation facilities exposes it to the risk of increased costs and reduced earnings. As part of its normal business operations, Idaho Power purchases coal and natural gas in the open market or under short-term, long-term, or variable-priced contracts. Market prices for coal and natural gas are influenced by factors impacting supply and demand such as weather conditions, fuel transportation availability, economic conditions, and changes in technology. Most of Idaho Power's coal supply arrangements are for coal originating in Wyoming and any disruption of coal production in, or transportation from, that region may cause Idaho Power to incur additional fuel supply costs or use alternative generation sources or wholesale market power purchases. Natural gas transportation to Idaho Power's natural gas plants is limited to one primary pipeline, presenting a heightened possibility of supply disruptions. Idaho Power is also exposed to the risk that its counterparties to fuel purchase arrangements will default on their obligations, causing Idaho Power to seek alternative sources of fuel or rely on other generation sources or wholesale market power purchases. Idaho Power may not be able to fully recover these increased costs through rates or its power cost adjustment mechanisms, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power’s generation, transmission, and distribution facilities are subject to numerous operational risks unique to it and its industry. Operating risks associated with Idaho Power's generation, transmission, and distribution facilities include equipment failures, volatility in fuel and transportation pricing, interruptions in fuel supplies, increased regulatory compliance costs, labor disputes, accidents and workforce safety matters, release of hazardous or toxic substances into the air or water, the failure of a hydroelectric facility, the loss of cost-effective disposal options for solid waste, operator error, and the occurrence of catastrophic events at the facilities. Diminished availability or performance of those facilities could result in reduced customer satisfaction and regulatory inquiries and fines. Operation of Idaho Power's owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and lower efficiency levels and result in lost revenues and increased expenses for alternative fuels or wholesale market power purchases. Accidents, fires, explosions, system damage or dysfunction, and other unplanned events related to Idaho Power's infrastructure may expose Idaho Power to claims for personal injury or property damage. Further, the transmission system in Idaho Power's service territory is constrained, limiting the ability to transmit electric energy within the service territory and access electric energy from outside the service territory during high-load periods. The transmission constraints could result in failure to provide reliable service to customers and the inability to deliver energy from generating facilities to the power grid, or not being able to access lower cost sources of electric energy, which could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

Volatility in the financial markets, or denial of regulatory authority to issue debt or equity securities, may negatively affect IDACORP’s and Idaho Power’s ability to access capital and/or increase their cost of borrowing, or result in losses on investments. IDACORP and Idaho Power require liquidity to pay operating expenses and principal of, and interest on, debt and to finance capital expenditures not satisfied by cash flows from operations. Financial markets have in recent years experienced extreme volatility and disruption, most recently as a result of the European sovereign debt situation, generally resulting in a decrease in the availability of liquidity and credit for borrowers. In a volatile credit environment, Idaho Power may be unable to issue long-term indebtedness at reasonable interest rates or at all, one or more of the participating banks in IDACORP’s and Idaho Power’s credit facilities may default on their obligations to make loans under, or may withdraw from, the credit facilities, or IDACORP’s and Idaho Power’s access to capital may otherwise be inhibited. In addition, at times Idaho Power has a relatively large balance of short-term investments. Volatility in the financial markets may result in a lack of liquidity for short-term investments and declines in value of some investments. The occurrence of any of these events could affect Idaho Power's ability to execute its business plan and adversely affect IDACORP’s and Idaho Power’s results of operations and financial condition. Further, Idaho

Power is required to obtain regulatory approval in Idaho, Oregon, and Wyoming in order to borrow money or to issue securities and is therefore dependent on the public utility commissions of those states to issue favorable orders in a timely manner to permit them to finance their operations. Notably, without additional approval from those commissions, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

A downgrade in IDACORP's and Idaho Power's credit ratings could affect the companies' ability to access capital, increase their cost of borrowing, and require the companies to post collateral with transaction counterparties. Access to capital markets is important to IDACORP's and Idaho Power's ability to operate and to complete capital projects, including its planned transmission projects. Credit rating agencies periodically review the corporate credit ratings and long-term ratings of IDACORP and Idaho Power, and these ratings impact access to, and the cost of, borrowing. IDACORP and Idaho Power also have borrowing arrangements that rely on the ability of the banks to fund loans or support commercial paper, a principal source

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of short-term financing. Downgrades of IDACORP’s or Idaho Power’s credit ratings, or those affecting relationship banks, could limit the companies’ ability to access capital, including commercial paper markets, require the companies to pay a higher interest rate on their debt, and require the companies to post additional performance assurance collateral with transaction counterparties.

Idaho Power’s risk management policy and programs relating to economically hedging power and gas exposures, financial and interest rate risk, and counterparty creditworthiness may not always perform as intended, and as a result IDACORP and Idaho Power may suffer economic losses. Idaho Power enters into transactions to hedge its positions in coal, natural gas, power, and other commodities, and enters into financial hedges. IDACORP and Idaho Power could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. The derivative instruments might not offset the underlying exposure being mitigated as intended, due to pricing inefficiencies or other terms of the derivative instruments, and any such failure to mitigate exposure could result in financial losses. Further, forecasts of future fuel needs and loads and available resources to meet those loads are inherently uncertain and may cause Idaho Power to over- or under-hedge actual resource needs, exposing the company to market risk on the over- or under-hedged position. As a result, risk management actions may adversely affect IDACORP’s and Idaho Power’s financial condition and results of operations.

Idaho Power could be subject to penalties and operational changes if it violates mandatory reliability and security requirements, which could adversely impact IDACORP's and Idaho Power's results of operations and financial condition. As an owner and operator of a bulk power transmission system, Idaho Power is subject to mandatory reliability standards issued by the North American Electric Reliability Corporation and enforced by the Federal Energy Regulatory Commission. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with reliability standards subjects Idaho Power to higher operating costs and increased capital expenditures. Further, Idaho Power has received in recent years notices of violations from, and self-reported reliability standard compliance issues to, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council, and has several matters pending. Potential monetary and non-monetary penalties for a violation of Federal Energy Regulatory Commission regulations may be substantial, and in some circumstances monetary penalties may be as high as $1 million per day per violation. The imposition of penalties on Idaho Power could have a negative effect on its and IDACORP’s results of operations and financial condition.

Federally mandated purchases of power from PURPA power projects, and integration of power generated from those projects into Idaho Power's system, may increase costs and decrease system reliability, and adversely affect Idaho Power's and IDACORP's results of operations and financial condition. An abundance of intermittent, non-dispatchable wind power generation at times when Idaho Power has available lower-cost resources to meet load demands has an impact on the operation of Idaho Power's hydroelectric generation plants, system reliability, power supply costs, and the wholesale power markets in the Pacific Northwest. Wind power generated from PURPA projects, which Idaho Power is generally obligated to purchase regardless of the then-current load demand or wholesale energy market prices, increases the likelihood and frequency that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources, increasing power purchase costs. Further, balancing load and generation from Idaho Power's power generation portfolio is challenging, and Idaho Power expects that its operational costs will increase as a result of its efforts to integrate intermittent, non-dispatchable power from a large number of PURPA power projects. Recent efforts to obtain further authorization to curtail certain intermittent power sources during light-load times have been unsuccessful. Idaho Power anticipates that costs will escalate as the volume of wind and other intermittent power on Idaho Power's system increases, which may negatively affect IDACORP's and Idaho Power's results of operations and financial condition.

The performance of pension and postretirement benefit plan investments and other factors impacting plan costs and funding obligations could adversely affect IDACORP's and Idaho Power's financial condition and results of operations

- primarily cash flows and liquidity. Idaho Power provides a noncontributory defined benefit pension plan covering most employees, as well as a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers eligible retirees. Costs of providing these benefits are based in part on the value of the plans' assets and, therefore, adverse investment performance for these assets could increase Idaho Power’s plan costs and funding requirements related to the plans. The key actuarial assumptions that affect funding obligations are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Idaho Power evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future equity and debt market performance, changes in interest rates, and other factors Idaho Power and its actuary firms use to develop the actuarial assumptions are inherently uncertain, and actual results could vary significantly from the estimates. Changes in demographics, including timing of retirements or changes in life expectancy assumptions, may also increase Idaho Power's plan costs and funding requirements. Future pension funding requirements and the timing of funding payments are also subject to the impacts of changes in legislation. Depending on the timing of contributions to the plans and Idaho Power's ability to recover costs through

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rates, cash contributions to the plans could reduce the cash available for operating activities. For additional information regarding Idaho Power's funding obligations under its benefit plans, see Note 11 - "Benefit Plans" to the consolidated financial statements included in this report.

As a holding company, IDACORP does not have its own operating income and must rely on the cash flows from its subsidiaries to pay dividends and make debt payments. IDACORP is a holding company with no significant operations of its own, and its primary assets are shares or other ownership interests of its subsidiaries, primarily Idaho Power. IDACORP’s subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to IDACORP, whether through dividends, loans, or other payments. The ability of IDACORP’s subsidiaries to pay dividends or make distributions to IDACORP depends on several factors, including each subsidiary's actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future first mortgage bonds and other debt or equity securities. Further, the amount and payment of dividends is at the discretion of the board of directors, which may reduce or cease payment of dividends at any time. See Item 5 - "Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities" in this report for a further description of restrictions on IDACORP's and Idaho Power's payment of dividends.

Changes in tax laws and regulations, or differing interpretation or enforcement of applicable laws by the Internal Revenue Service or other taxing jurisdictions, could have a material adverse impact on IDACORP’s or Idaho Power’s financial condition and results of operations. IDACORP and Idaho Power must make judgments and interpretations about the application of the law when determining the provision for taxes. The companies’ tax obligations include income, real estate, public utility, municipal, sales and use, business and occupation, and employment-related taxes and ongoing issues related to these taxes. These judgments may include reserves for potential adverse outcomes regarding tax positions that may be subject to challenge by taxing authorities. In recent years, tax settlements, as well as state regulatory mechanisms with tax-related provisions (such as Idaho Power's December 2011 settlement with the Idaho Public Utilities Commission), have significantly impacted IDACORP's and Idaho Power's results of operations. The outcome of ongoing and future income tax proceedings, or the state public utility commissions' treatment of those tax outcomes, could differ materially from the amounts IDACORP and Idaho Power record prior to conclusion of those proceedings, and the difference could negatively affect IDACORP’s and Idaho Power’s earnings and cash flows. Further, in some instances the treatment from a ratemaking perspective of any tax benefits could be different than IDACORP or Idaho Power anticipate or request from applicable state regulatory commissions, which could have a negative effect on their financial condition and results of operations.

Employee workforce factors, including the impacts of an aging workforce with specialized utility-specific functions, could increase costs and adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power is subject to workforce factors, including loss or retirement of key personnel, availability of qualified personnel, an aging workforce, and impacts of efforts to organize the workforce. A unionization attempt that was launched in late-2012 failed, but does not prevent future unionization attempts. Idaho Power’s operations require a skilled workforce to perform specialized utility functions. Many of these positions, such as linemen, grid operators, and generation plant operators, require extensive, specialized training. Idaho Power expects that a significant portion of its skilled workforce will be retiring within the current decade, which will require Idaho Power to attract, train, and retain skilled workers to prevent a loss of institutional knowledge and avoid a skills gap. Without a skilled workforce, Idaho Power’s ability to provide quality service to its customers and meet regulatory requirements will be challenging, which could negatively affect earnings. The costs associated with attracting and retaining appropriately qualified employees to replace an aging and skilled workforce could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

IDACORP and Idaho Power are subject to costs and other effects of legal and regulatory proceedings, disputes, and claims. From time to time in the normal course of business IDACORP and Idaho Power are subject to various lawsuits, regulatory proceedings, disputes, and claims that could result in adverse judgments or settlements, fines, penalties, injunctions, or other relief. These matters are subject to a number of uncertainties, and as a result management is often unable to predict the outcome of a matter. As an example, over the past decade Idaho Power has been a party to proceedings relating to high prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001, which caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the Federal Energy Regulatory Commission to initiate its own investigations. While Idaho Power has largely disposed of direct claims in those proceedings, the settlements and associated Federal Energy Regulatory Commission orders did not eliminate the potential for speculative "ripple claims," which involve potential claims for refunds from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. Idaho Power's settlement payments in those proceedings have been relatively small to date, but the legal costs of defending the claims over the past decade have been substantial. In recent years, Idaho Power has also been a party to legal proceedings advanced by private

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parties relating to alleged violations of environmental laws at coal-fired plants. The legal costs and final resolution of matters in which IDACORP or Idaho Power are involved could have a negative effect on their financial condition and results of operations. Similarly, the terms of resolution could require the companies to change their business practices and procedures, which could also have a negative affect on their financial positions and results of operations.

Acts or threats of terrorism, cyber attacks, security breaches, and other acts of individuals or groups seeking to disrupt Idaho Power's operations, or the businesses of third parties, could negatively impact IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power's generation and transmission facilities are potential targets for terrorist acts and threats, as well as cyber attacks and other disruptive activities of individuals or groups. Some of Idaho Power's facilities are deemed "critical infrastructure," in that incapacity or destruction of the facilities could have a debilitating impact on security, reliability or operability of the bulk electric power system, national economic security, national public health or safety, or any combination of those matters. The possibility that infrastructure facilities, such as generation facilities and electric transmission facilities, would be direct targets of, or indirect casualties of, an act of terror or cyber attack (whether originating internally or externally) may affect Idaho Power's operations by limiting the ability to generate, purchase, or transmit power and by delaying the development and construction of new generating and transmission facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure Idaho Power's assets, and could further adversely affect Idaho Power's operations by contributing to disruption of supplies and markets for natural gas or coal used to fuel gas- or coal-fired power plants.

In the normal course of business, Idaho Power collects, processes, and retains sensitive and confidential customer and proprietary information, and operates systems that directly impact the availability of electric power and the transmission of electric power in the electric grid. Despite the security measures in place, Idaho Power's facilities and systems could be vulnerable to security breaches, data leakage, or other similar events that could interrupt operations, exposing Idaho Power to liability. Those breaches and events may result from acts of Idaho Power employees, contractors, or third parties. If Idaho Power's information technology and security systems were to fail or be breached and Idaho Power were unable to recover the systems and/or data in a timely manner, Idaho Power may be unable to fulfill critical business functions. In such case, confidential and proprietary business, employee, or customer information could be compromised, exposing Idaho Power to liability and causing business disruptions, which could negatively affect Idaho Power's business operations and IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power's business and operations may be adversely affected by its inability to successfully implement current information technology projects. Idaho Power is currently undertaking several multi-year company-wide information technology solution upgrades intended to replace existing software and systems. These projects include a new customer information system, Idaho Power's SmartGrid initiative, and migration from Idaho Power's existing mainframe system to an open system. Idaho Power is also implementing systems to augment and improve its ability to pinpoint the sources of electric system outages, respond to them more quickly, and focus repair efforts. Implementation of these information systems and technology solutions is complex, expensive, and time consuming. If Idaho Power does not successfully implement the new systems and processes, or if the systems do not operate as intended or cause data or operational errors, it could result in substantial disruptions to Idaho Power's business, which could have a material adverse effect on IDACORP's and Idaho Power's results of operations and financial condition.

Changes in accounting standards or Securities and Exchange Commission rules may impact IDACORP's and Idaho Power's financial results and disclosures. The Financial Accounting Standards Board and the Securities and Exchange Commission may make changes to accounting standards that impact presentation and disclosures of financial condition and results of operations. Further, new accounting orders issued by the Federal Energy Regulatory Commission could significantly impact IDACORP's and Idaho Power's reported financial condition. Idaho Power meets conditions under generally accepted accounting principles to reflect the impact of regulatory decisions in its financial statements and to defer certain costs as regulatory assets until those costs are collected in rates, and to defer some items as regulatory liabilities. Idaho Power expects to recover its regulatory assets from customers through rates but recovery is subject to review by the regulatory bodies. If recovery of these amounts ceases to be probable, if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power could be required to eliminate those regulatory assets or liabilities. Any of these circumstances could result in write-offs and have a material effect on IDACORP's and Idaho Power's reported financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Idaho Power's properties consist of the physical assets necessary to support its electricity business, which include electric generation, transmission, and distribution facilities, as well as coal assets that support one of its coal-fired generation plants. In addition to these physical assets, Idaho Power has rights-of-way and water rights that enable it to utilize its facilities. Idaho Power's system is comprised of 17 hydroelectric generating plants located in southern Idaho and eastern Oregon, three natural gas-fired plants located in southern Idaho, and interests in three coal-fired steam electric generating plants located in Wyoming, Nevada, and Oregon. As of December 31, 2012, the system also includes approximately 4,851 pole miles of high-voltage transmission lines, 24 step-up transmission substations located at power plants, 24 transmission substations, 10 switching stations, 228 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 26,764 pole miles of distribution lines.

Idaho Power holds FERC licenses for all of its hydroelectric projects that are subject to federal licensing. Relicensing of Idaho Power's hydroelectric projects is discussed in Item 7 - "MD&A – Regulatory Matters – Relicensing of Hydroelectric Projects."
Idaho Power's hydroelectric projects and other owned and co-owned generating facilities and their nameplate capacities are listed below.

Project	Nameplate Capacity (kW)[1]	License Expiration	
Hydroelectric Projects:			
Properties Subject to Federal Licenses:			
Lower Salmon	60,000	2034	
Bliss	75,000	2034	
Upper Salmon	34,500	2034	
Shoshone Falls	12,500	2034	
CJ Strike	82,800	2034	
Upper Malad - Lower Malad	21,770	2035	
Brownlee - Oxbow - Hells Canyon (Hells Canyon Complex)	1,166,900	2005	(2)
Swan Falls	27,170	2042	
American Falls	92,340	2025	
Cascade	12,420	2031	
Milner	59,448	2038	
Twin Falls	52,897	2040	
Other Hydroelectric:			
Clear Lakes - Thousand Springs	11,300		
Total Hydroelectric	1,709,045		
Steam and Other Generating Plants:			
Jim Bridger (coal-fired) [3]	770,501		
Valmy (coal-fired) [3]	283,500		
Boardman (coal-fired) [3][4]	64,200		
Danskin (gas-fired)	270,900		
Langley Gulch (gas-fired)	318,452		
Bennett Mountain (gas-fired)	172,800		
Salmon (diesel-internal combustion)	5,000		
Total Steam and Other	1,885,353		
Total Generation	3,594,398		

[1] Actual generation capacity from a facility may be greater or less than the rated nameplate generation capacity.

[2] Licensed on an annual basis while the application for a new multi-year license is pending.
[3] Idaho Power's ownership interests are 33 percent for Jim Bridger, 50 percent for Valmy, and 10 percent for Boardman. Amounts shown represent Idaho Power's share.
[4] Pursuant to an Oregon Environmental Quality Commission plan and associated rules, the Boardman power plant is scheduled for cessation of coal-fired operations by December 31, 2020.

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Idaho Power's headquarters are located in Boise, Idaho, consisting of approximately 334,000 square feet of owned office space throughout the corporate campus. Idaho Power also leases approximately 84,000 square feet of office space in Boise for corporate, engineering, and administrative functions, and owns and leases approximately 468,000 square feet of office, operations, and warehouse space in various other locations throughout Idaho Power's service territory in Idaho and Oregon, excluding supportive offices located at generation facilities.

Idaho Power owns all of its interests in principal plants and other important units of real property, except for portions of certain projects licensed under the FPA and reservoirs and other easements. Substantially all of Idaho Power’s property is subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. Idaho Power’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, Idaho Power of such properties. Idaho Power considers its properties to be well-maintained and in good operating condition.

IERCo owns a one-third interest in BCC 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.

ITEM 3. LEGAL PROCEEDINGS

Refer to Note 10 – “Contingencies” to IDACORP’s and Idaho Power’s consolidated financial statements included in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 of this report.

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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 (NYSE). On February 15, 2013, there were 11,898 holders of record of IDACORP common stock and the closing stock price was $46.73 per share. The outstanding shares of Idaho Power’s common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of Idaho Power on October 1, 1998.

The amount and timing of dividends paid 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, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deem relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power. At its November 2011 meeting, the IDACORP board of directors adopted a dividend policy for IDACORP that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the board of director's dividend decisions. Notwithstanding the dividend policy adopted by the IDACORP board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will take into account the foregoing factors, among others.

A covenant under IDACORP’s credit facility and Idaho Power’s credit facility described in Part II, Item 7 - “MD&A – Liquidity and Capital Resources - Financing Programs – Credit Facilities” requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined in the respective credit facilities, of no more than 65 percent at the end of each fiscal quarter.

Idaho Power’s Revised Code of Conduct approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power’s common equity capital below 35 percent of its total adjusted capital without IPUC approval. Idaho Power’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 violate the covenants or Idaho Power’s Code of Conduct. At December 31, 2012, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. Based on these restrictions, IDACORP’s and Idaho Power’s dividends were limited to $889 million and $794 million, respectively, at December 31, 2012. Idaho Power must obtain approval of the OPUC before it can directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power’s articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. Idaho Power has no preferred stock outstanding. IDACORP and Idaho Power paid dividends of $69 million, $60 million, and $58 million in 2012, 2011, and 2010, respectively.

On January 19, 2012, IDACORP's board of directors voted to increase the quarterly dividend payable February 29, 2012 to $0.33 per share of IDACORP common stock, from the prior dividend amount of $0.30 per share of IDACORP common stock. On September 20, 2012, IDACORP's board of directors voted to increase the quarterly dividend, commencing with the dividend payable on November 30, 2012, to $0.38 per share of IDACORP common stock. For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP's and Idaho Power's payment of dividends, see Note 6 - “Common Stock” to the consolidated financial statements included in this report.

The following table shows the reported high and low sales price of IDACORP's common stock and dividends paid for 2012 and 2011 as reported by the NYSE.

	2012			2011		
Quarter	High	Low	Dividends paid per share	High	Low	Dividends paid per share
1st	$42.89	$39.66	$0.33	$38.72	$36.14	$0.30
2nd	42.22	38.17	0.33	40.38	37.65	0.30
3rd	44.03	41.00	0.33	40.71	33.88	0.30
4th	45.67	40.18	0.38	42.66	37.26	0.30

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During 2011, 2010, and 2009, Idaho Power paid dividends to its parent, IDACORP, in the amounts shown in Idaho Power's Consolidated Statements of Retained Earnings included in this report.

IDACORP, Inc. did not repurchase any shares of its common stock during the fourth quarter of 2012.

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, 2007, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.
Source: Bloomberg and EEI

	2007	2008	2009	2010	2011	2012
IDACORP	$100.00	$86.99	$98.78	$118.39	$140.00	$147.94
S&P 500	100.00	63.01	79.69	91.71	93.62	108.59
EEI Electric Utilities Index	100.00	74.10	82.03	87.80	105.35	107.55

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 Idaho Power under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent IDACORP or Idaho Power 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)

	2012	2011	2010	2009	2008
Operating revenues	$1,080,662	$1,026,756	$1,036,029	$1,049,800	$960,414
Operating income	242,602	155,352	191,811	196,363	183,818
Net income attributable to IDACORP, Inc.	168,761	166,693	142,798	124,350	98,414
Diluted earnings per share from continuing operations	3.37	3.36	2.95	2.51	2.17
Dividends declared per share	1.37	1.20	1.20	1.20	1.20
Financial Condition:					
Total assets	$5,319,516	$4,960,609	$4,238,727	$4,022,845	$3,653,308
Long-term debt (including current portion)	1,537,696	1,488,614	1,419,070	1,269,979	1,168,336
Financial Statistics:					
Times interest charges earned:					
Before tax (1)	3.27	2.35	2.65	2.88	2.47
After tax (2)	2.97	2.97	2.66	2.59	2.23
Book value per share (3)	$35.07	$33.18	$31.01	$29.17	$27.76
Market-to-book ratio (4)	124 %	128 %	119 %	110 %	106 %
Payout ratio (5)	41 %	36 %	41 %	45 %	55 %
Return on year-end common equity (6)	9.6 %	10.1 %	9.3 %	8.9 %	7.6 %

The financial statistics listed above are calculated in the following manner:
(1) The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.
(2) The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.
(3) Total equity, excluding non-controlling interests, at the end of the year divided by shares outstanding at the end of the year.
(4) The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in footnote (3) above.
(5) Dividends paid per common share divided by diluted earnings per share.
(6) Net income attributable to IDACORP, Inc. divided by total equity, excluding non-controlling interests, at the end of the year.

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

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, Idaho Power) are discussed. While reading the MD&A, please refer to the accompanying consolidated financial statements of IDACORP and Idaho Power. Also refer to "Cautionary Note Regarding Forward-Looking Statements" and Part 1 - Item 1A - "Risk Factors" in this report for important information regarding forward-looking statements made in this MD&A and elsewhere in this report.

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. IDACORP's common stock is listed and trades on the New York Stock Exchange under the trading symbol "IDA." Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power provided electric service to approximately 501,000 general business customers as of December 31, 2012. As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), which determine the rates that Idaho Power charges to its general business customers. Also, as a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its Federal Energy Regulatory Commission (FERC) tariff and to provide transmission services under its FERC open access transmission tariff (OATT). Idaho Power uses general rate cases, cost adjustment mechanisms, and subject-specific filings to recover its costs of providing service and the costs of its energy efficiency and demand-side resources programs, and to seek to earn a return on investment.

Idaho Power generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its Idaho and Oregon service territories, as well as from the wholesale sale and transmission of electricity. Idaho Power's revenues and income from operations are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, availability of water for hydroelectric generation, price changes, customer usage patterns (which are affected in large part by the condition of the local economy), and the availability and price of purchased power and fuel. Idaho Power experiences its highest retail energy sales during the summer irrigation and cooling season, with a lower peak in the winter that generally results from heating demand. IDACORP's and Idaho Power's financial condition are also affected by regulatory decisions through which Idaho Power seeks to recover its costs on a timely basis and earn an authorized return on investment, and by the ability to obtain financing through the issuance of debt and/or equity securities.

IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co., which is the former limited partner of, and successor by merger to, IDACORP Energy L.P., a marketer of energy commodities that wound down operations in 2003. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

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EXECUTIVE OVERVIEW

Brief Overview of 2012 Results

IDACORP's 2012 earnings per diluted share of $3.37 were one cent above its 2011 earnings per diluted share of $3.36 and reflect the impacts of general rate increases that went into effect during 2011 and 2012 and increased irrigation sales volumes. Idaho Power's 2012 return on year-end equity in the Idaho jurisdiction exceeded 10.5 percent, triggering the sharing mechanism in Idaho Power's December 2011 settlement agreement, discussed below, and resulting in a $21.8 million reduction to operating income, reflecting earnings to be shared with Idaho customers to reduce rates. For purposes of comparison, during 2011 IDACORP's earnings were significantly impacted by the recognition of $56.9 million in tax benefits relating to prior tax years. The 2011 tax benefit, combined with operating results, triggered a similar sharing mechanism in Idaho during 2011 that reduced 2011 operating income by $47.4 million. A more specific discussion of the factors influencing IDACORP's and Idaho Power's results for 2012, including a quantification of their respective impacts, is included below in this MD&A.

2012 Accomplishments and 2013 Initiatives

IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business. For the past several years, Idaho Power has been implementing its three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. This strategy is described in Part I, Item 1 - "Business" of this report. Examples of Idaho Power's achievements during 2012 under its three-part business strategy include:

- commencement of the Langley Gulch power plant's commercial operation, ahead of schedule and within budget;
- continued execution of Idaho Power's purposeful regulatory strategy, which resulted in approval of Idaho Power's requests for recovery of, and a return on, Idaho Power's investment in the Langley Gulch power plant, a general rate increase in Idaho on January 1, 2012, and the issuance of an order by the IPUC pertaining to PURPA-related matters;
- continued progress toward the permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects and execution of associated cost-sharing agreements with PacifiCorp and the Bonneville Power Administration (BPA);
- continued progress toward achieving IDACORP's previously adopted dividend policy; during 2012 the IDACORP Board of Directors voted to increase the quarterly dividend twice, resulting in an aggregate increase from $0.30 per share quarterly to $0.38 per share quarterly, or nearly 27 percent;
- receipt of a 30-year license from the FERC for the continued operation of the Swan Falls hydroelectric facility;
- ranking in the top quartile of the 126 largest utilities in the country for customer satisfaction in the J.D. Power and Associates 2012 Electric Utility Residential Customer Satisfaction Study;
- recognition for Highest Customer Satisfaction with Business Electric Service in the Western U.S. among Midsize Utilities in a Tie in the J.D. Power and Associates 2012 Electric Utility Business Customer Satisfaction Study of more than 90 utility brands across the U.S.; and
- ranking among the "40 Best Energy Companies" by Public Utilities Fortnightly.

One of management's primary goals during 2011 and 2012 was to reduce Idaho Power's regulatory lag, which results from the period of time between making an investment or incurring an expense and earning a return and recovering that investment or expense. Management focused heavily on implementation of new rates and approval of regulatory mechanisms during 2011 and 2012. As Idaho Power transitions to 2013 and into 2014 it will focus on optimizing operations and managing growth in expenses in an effort to achieve or exceed a rate of return reflective of those allowed by the IPUC and OPUC. Management anticipates that the IDACORP Board of Directors will, when appropriate, take steps during 2013 in furtherance of the dividend policy it adopted in November 2011, which provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings.

Other specific matters that the companies expect will require management's focus and attention in 2013 include continued efforts toward permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects, completion and filing of the 2013 integrated resource plan (IRP), implementation of a significant new customer relations and billing system, and continued work toward federal relicensing of the Hells Canyon Complex (HCC) hydroelectric facility.

For 2013, in addition to its specific projects, Idaho Power has established a number of organizational initiatives, including the following:

- actively manage through the challenging economic environment by optimizing business practices, maintaining capital liquidity, and maintaining credit ratings;
- continue to emphasize innovative approaches to regulatory strategy;

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- promote economic development through collaboration with the states of Idaho and Oregon to attract new businesses that fit Idaho Power's resource and load profile mix;
- focus on operational excellence by matching resources to customer loads, managing the impacts of environmental regulations, maintaining Idaho Power's hydroelectric base, enhancing power quality and reliability, and customer satisfaction; and
- maintain an enterprise safety culture and an effective and motivated workforce, address workforce attrition, and enhance succession planning and training programs in anticipation of a significant number of retirements in the next few years.

Overview of General Factors and Trends Affecting Results of Operations and Financial Condition

IDACORP's and Idaho Power's results of operations and financial condition are affected by regulatory, economic, and other factors, many of which are described below.

Emphasis on Regulatory Cost Recovery and Expense Management; Support from Regulatory Settlement: The price that Idaho Power is authorized to charge for its electric service is a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. Because of the significant impact of ratemaking decisions, and in furtherance of its goal of advancing a purposeful regulatory strategy, Idaho Power has focused on timely recovery of its costs through filings with the company's regulators, and the prudent management of expenses and investments after receiving rate orders from the IPUC and OPUC. Effective implementation of Idaho Power's regulatory strategy is particularly important in a climate of slow economic recovery that continues to put pressure on regulators to limit rate increases or otherwise take actions to limit the potential adverse impact of rate increases on customers.

The number of regulatory filings and activity during the period from 2010 to 2012 exceeded historical averages, driven by Idaho Power's regulatory strategy. The rate orders Idaho Power has received in recent years and their associated mechanisms have decreased the likelihood that Idaho Power would seek rate relief through a general revenue rate case during 2013, and instead focus on optimizing business operations and processes. Particularly notable regulatory developments that have impacted or that IDACORP and Idaho Power expect will impact results, each of which is discussed in more detail under "Regulatory Matters" in this MD&A or in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, include the following:

Proceeding	Description	Amount and Timing of Rate Increase/Decrease
Idaho General Rate Case Settlement	General rate case, requesting an increase in Idaho-jurisdiction base rates	IPUC approved a $34.0 million increase in rates, effective January 1, 2012
Langley Gulch Power Plant	Request for recovery of and return on Idaho Power's investment in the Langley Gulch power plant, including operating costs	IPUC approved a $58.1 million increase in rates, effective July 1, 2012; OPUC approved a $3.0 million increase in rates effective October 1, 2012
Revenue Sharing	Rate adjustment pursuant to January 2010 and December 2011 settlement agreements[1]	IPUC approved a $27.1 million decrease in rates, effective only for the period from June 1, 2012 to May 31, 2013[1]
Oregon General Rate Case Settlement	General rate case, requesting an increase in Oregon-jurisdiction base rates	OPUC approved a $1.8 million increase in rates, effective March 1, 2012

(1) The rate change for the Idaho PCA was partially offset by the revenue-sharing order issued pursuant to the January 2010 and December 2011 settlement agreements. Idaho Power's revenue-sharing arrangements had two components: (a) a PCA mechanism component, which reduced net rates by $27.1 million, and (b) a pension balancing account component, which resulted in a $20.3 million net reduction to Idaho Power's pension regulatory asset (reducing Idaho customers' future obligation). Idaho Power recorded the $27.1

million revenue reduction and $20.3 million pension regulatory asset reduction in 2011.

In addition to the rate changes listed in the table above, in December 2011 the IPUC approved a settlement stipulation, separate from the Idaho general rate case settlement, that permits Idaho Power to amortize additional accumulated deferred investment tax credits (ADITC) to help achieve a minimum 9.5 percent rate of return on year-end equity in the Idaho jurisdiction (Idaho ROE) in 2012, 2013, and 2014, subject to prescribed limits and conditions. The settlement stipulation also provides for the potential sharing between the company and customers of Idaho-jurisdictional earnings in excess of specified levels of Idaho ROE. The specific terms of the settlement stipulation are described in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report. While providing no assurance that Idaho Power will obtain a 9.5 percent Idaho ROE in any of the years, IDACORP and Idaho Power believe the ability to amortize additional ADITC provides an element of earnings stability for 2013 and 2014. Because its 2012 Idaho ROE exceeded 9.5

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percent, Idaho Power did not amortize additional ADITC in 2012 under the settlement stipulation. Based on the terms of the December 2011 settlement stipulation, Idaho Power recorded during 2012 a $7.2 million provision against current revenues, as a benefit to Idaho customers in the form of a future rate reduction, and an additional $14.6 million of pension expense, which will benefit Idaho customers by reducing the amount of deferred pension expense that will be collected from customers in the future. Idaho Power recorded $47.4 million for the impact of similar sharing mechanisms in 2011.

Economic Conditions and Customer/Load Growth: When seeking to predict utility load changes for both short-term load forecasts and long-term infrastructure planning purposes, Idaho Power monitors a number of economic indicators, including employment rates, growth in customer numbers, and foreclosure rates and other housing-related data on both a national scale and within Idaho Power's service territory. Economic conditions can impact consumer demand for electricity, collectability of accounts, the volume of off-system sales, and the need to purchase power to meet demand.

Since 2008, economic conditions in Idaho Power's service territory have been relatively weak. However, a number of improvements in economic conditions have occurred over the last few months. After peaking at 10.0 percent in early 2011, the service area unemployment rate fell to 8.4 percent by the end of 2011 and reached 6.2 percent by the end of 2012, according to Idaho Department of Labor data. The housing market in Idaho Power's service territory has improved when measured by foreclosure rates and the available supply and pricing of housing. Idaho Power also continues to experience customer growth, and a number of businesses have constructed facilities in Idaho Power's service territory. For the year ended December 31, 2012, the customer growth rate in Idaho Power's service territory was approximately 1.1 percent—roughly twice the growth rate of the prior two years. However, by comparison, for the 20-year period ending in 2011 the average annual customer growth rate in Idaho Power's service territory was 2.6 percent. Idaho Power predicts that customer growth within its service territory in the next few years will be positive, though at a rate below the 20-year historical annual average.

In light of the uncertainty of the timing and pace of economic recovery in its service territory, and general underlying concerns remaining about the strength and pace of recovery of the economy and financial markets, Idaho Power continues to manage costs while executing its three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use. As the customer growth rate and demand have potentially stabilized, Idaho Power is transitioning from an emphasis on large capital projects, particularly generation, to an emphasis on maintaining and replacing aging assets while planning and building for the future. Idaho Power plans to control operating and maintenance and capital costs through process and project reviews and through process improvement initiatives, and by empowering employees to identify means to reduce costs, build efficiencies, and enhance individual and enterprise performance. These actions are particularly important at a time when customer growth is relatively low and new rates have been approved and implemented.

In December 2012, Idaho Power filed an application with the IPUC requesting the temporary suspension during 2013 of two demand response programs that Idaho Power had previously implemented to reduce peak-hour loads. Included was a discussion of the results of preliminary studies conducted in connection with Idaho Power's 2013 IRP, including a load and resource balance for the 2013 to 2032 period. After application of a number of assumptions, under a scenario that excludes demand response programs and power capacity from the proposed Boardman-to-Hemingway 500-kV transmission line, the peak-hour load and resource balance indicates no peak-hour load deficit until 2016, which under those assumptions the need for near-term peak-hour resources like demand response programs or new near-term supply-side resources does not exist. While these results preliminarily suggest that new generation projects are not necessary in the near-term, Idaho Power has not completed its analysis and will not have completed its analysis until the publication of its 2013 IRP in mid-2013. The 2013 IRP will describe the estimated timing of potential generation and transmission projects.

Weather Conditions and Associated Impacts: Weather and agricultural growing conditions have a significant impact on energy sales and the seasonality of those sales. Relatively low and high temperatures result in greater energy usage for heating and cooling, respectively. During the agricultural growing season, which in large part occurs during the second and third quarters, irrigation customers use electricity to operate irrigation pumps. For instance, the 2.6-percent increase in energy use by general business customers during 2012 compared to 2011 was largely attributable to agricultural growing conditions from April through June that required above average use of irrigation equipment. As noted above, Idaho Power also has tiered rates and seasonal rates, which contribute to increased revenues during higher-load periods, most notably the third quarter of each year when customer demand is typically at its peak. On July 12, 2012, Idaho Power achieved a record load demand of 3,245 MW. The previous record load demand was 3,214 MW, set on June 30, 2008.

Idaho Power's hydroelectric facilities comprise nearly one-half of Idaho Power's nameplate generation capacity. The availability and volume of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, base flows in the Snake River, spring flows, rainfall, water leases and other water rights, and other weather and stream flow considerations. Idaho Power expects

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hydroelectric generation during 2013 to be in the range of 6.0 to 8.0 million megawatt-hours (MWh), based on reservoir storage levels and forecasted weather conditions as of the date of this report, compared to actual generation of 8.0 million MWh in 2012, 10.9 million MWh in 2011, and 7.3 million MWh in 2010. Median annual hydroelectric generation is 8.6 million MWh. When hydroelectric generation is reduced Idaho Power must rely on more expensive generation sources and purchased power; however, most of the increase in power supply costs is deferred as a regulatory asset and collected from customers through its Idaho and Oregon power cost adjustment (PCA) mechanisms described later in this MD&A. Conversely, in periods of greater hydroelectric generation most of the resulting decrease in power supply costs that typically occurs is returned to customers through the PCA mechanisms.

Where favorable hydroelectric generating conditions exist for Idaho Power, they also may be abundant for other Pacific Northwest hydroelectric facility operators, thus increasing the available supply of lower-cost power and depressing regional wholesale market prices, which impacts the revenue Idaho Power receives from off-system sales of its excess power. Conversely, when hydroelectric generating conditions are poor, wholesale market prices may be higher due to lower supply, but Idaho Power would have less surplus energy available for sale into the wholesale markets. Again, much of the adverse or favorable impact of these costs is addressed through the PCA mechanisms.

Fuel and Purchased Power Expense: In addition to hydroelectric generation and power it purchases in the wholesale markets, Idaho Power relies significantly on coal and natural gas to fuel its generation facilities. Fuel costs are impacted by electricity sales volumes, the terms of contracts for fuel, Idaho Power's power generation capacity, the rate of expansion of alternative energy generation sources such as wind energy, the availability of hydroelectric generation resources, transmission capacity, energy market prices, and Idaho Power's hedging program for managing fuel costs. Operation of Idaho Power's newly constructed Langley Gulch power plant has increased Idaho Power's use of natural gas as a generation fuel, and thus its exposure to volatility in natural gas prices.

Purchased power costs are impacted by the terms of contracts for purchased power, the rate of expansion of alternative energy generation sources such as wind energy, and wholesale energy market prices. Idaho Power is obligated to purchase power from some PURPA generation projects at a specified price regardless of the then-current load demand or wholesale energy market prices. This increases the likelihood that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources and may be required to sell in the wholesale power market the power it purchases from PURPA projects at a significant loss. Integration of intermittent, non-dispatchable resources (such as wind energy) into Idaho Power's portfolio also creates a number of complex operational risks and challenges that Idaho Power is working to address, including through evaluation of the results of a recent comprehensive wind integration study. Notably, integration of these sources of power into Idaho Power's portfolio does not eliminate Idaho Power's need to construct facilities and infrastructure that provide reliable power. For instance, at the time Idaho Power reached its all-time system peak demand of 3,245 MW on July 12, 2012, wind resources on Idaho Power's system, representing roughly 500 MW of capacity, were contributing only 14 MW of power due to lack of wind. Increases in federally mandated PURPA power purchases were a significant driver of increased power purchase costs during 2012 and will likely continue to push power purchase costs, and correspondingly, customer rates, higher.

The Idaho and Oregon PCA mechanisms mitigate in large part the potential adverse impacts to Idaho Power of fluctuations in Idaho Power's power supply costs, including 100-percent of the Idaho-jurisdiction PURPA power purchase costs. Idaho Power also uses physical and financial forward contracts for both electricity and fuel in order to manage the risks relating to fuel and power price exposures.

Regulatory and Environmental Compliance Costs and Expenditures: Idaho Power is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and audits, including FERC and North American Electric Reliability Corporation (NERC) reliability requirements. Compliance with these requirements directly influences Idaho Power's operating environment and may significantly increase Idaho Power's operating costs.

Further, potential monetary and non-monetary penalties for a violation of applicable laws or regulations may be substantial. Accordingly, Idaho Power has in place numerous compliance policies and initiatives, and frequently evaluates, updates, and supplements those policies and initiatives.

In particular, environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power cease operating certain power generation plants. For instance, the Boardman coal-fired power plant, in which Idaho Power owns a 10-percent interest, is scheduled to cease coal-fired operations by the end of 2020, the decision for which was driven in large part by the substantial cost of environmental controls. Idaho Power expects to spend a considerable amount on environmental compliance and controls in the next decade. As legislation and regulations concerning

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greenhouse gas emissions develop, Idaho Power assesses, when and to the extent determinable, the potential impact on the costs to operate its power generation facilities, as well as the willingness or ability of joint owners of power plants to fund any required pollution control equipment upgrades in lieu of early plant retirements. For instance, Idaho Power recently concluded cost studies and scenario analyses to assess the potential future investments necessary for the continued operation of the Jim Bridger and Valmy coal-fired generation facilities. Idaho Power published the results of the study with its IRP update filed with the OPUC in February 2013, concluding that planned investments in environmental controls at the plants are appropriate.

Other Notable Matters and Areas of Focus

Pension Plan Funding: From 2010 to 2012 Idaho Power contributed $123 million to its defined benefit pension plan. In May 2011 the IPUC authorized Idaho Power to increase its annual recovery and amortization of deferred pension costs from $5.4 million to $17.1 million. While Idaho Power does not anticipate that any cash contributions will be required in 2013, it does expect to make additional significant cash contributions to the pension plan in the future. Idaho Power defers pension costs related to its Idaho jurisdiction until those costs are recovered through rates. While the IPUC's authorization to increase the annual recovery has mitigated in large part the adverse impacts of the contributions, the magnitude of the contributions relative to the annual cost recovery creates a lag between the timing of expenditures and their recovery, which impacts IDACORP's and Idaho Power's cash flows. While Idaho Power does not, as of the date of this report, have an expected date to request from regulators an additional increase in cost recovery, it may determine to do so if future contributions continue to be similar in magnitude to those made in recent years.

Water Management and Relicensing of the Hells Canyon Hydroelectric Project: Because of Idaho Power's reliance on stream flow in the Snake River and its tributaries, Idaho Power participates in numerous proceedings and venues that may affect its water rights, seeking to preserve the long-term availability of its rights for use at its hydroelectric projects. Also, Idaho Power is involved in renewing federal licenses for the HCC, its largest hydroelectric generation source, and recently received a 30-year license renewal from the FERC for its Swan Falls hydroelectric project. Relicensing involves numerous environmental issues and substantial costs. Idaho Power is working with the states of Idaho and Oregon, regulatory authorities, and interested parties to address concerns and take appropriate measures relating to the relicensing of the HCC. However, given the number of parties and issues involved, Idaho Power's relicensing costs have been and will continue to be substantial.

Transmission Projects: Idaho Power continues to focus on expansion of its transmission system in an effort to improve system reliability and access to wholesale markets. Its most notable projects in progress include the proposed Boardman-to-Hemingway and Gateway West 500-kV transmission projects. In January 2012, Idaho Power entered into cost-sharing arrangements with third parties for the permitting phases of both projects. Construction of these projects cannot commence until all federal, state, and local regulatory requirements are met. Based on Idaho Power's assessment of the status and future milestones for the Boardman-to-Hemingway project, Idaho Power has determined that an in-service date prior to 2018 is unlikely.

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Summary of 2012 Financial Results

The following is a summary of Idaho Power's net income, net income attributable to IDACORP, and IDACORP's earnings per diluted share for the years ended December 31, 2012, 2011, and 2010 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2012	2011	2010
Idaho Power net income	$168,168	$164,750	$140,634
Net income attributable to IDACORP, Inc.	$168,761	$166,693	$142,798
Average outstanding shares – diluted (000's)	50,010	49,558	48,340
IDACORP, Inc. earnings per diluted share	$3.37	$3.36	$2.95

The following table presents a reconciliation of net income attributable to IDACORP, Inc. for 2011 to 2012 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2011			$166.7
Change in Idaho Power net income before taxes:			
Rate and other regulatory changes, including power cost adjustment, pension expense recovery, and fixed cost adjustment mechanisms		$65.2	
Changes in sales volumes		16.1	
Change in payroll-related expenses		(6.8)	
Change in pension expense funded through rate increases		(5.1)	
Increased depreciation expense, property tax, and other		(8.7)	
Increase in Idaho Power operating income prior to sharing mechanisms		60.7	
Greater pension expense in 2011 than in 2012 as a result of sharing mechanisms	5.7		
Greater revenue sharing in 2011 than in 2012	19.9		
Increase in operating income as a result of sharing mechanisms		25.6	
Increase in Idaho Power operating income		86.3	
Decrease in allowance for funds used during construction (AFUDC)		(4.5)	
Other net decreases		(1.0)	
Change in income tax expense		(22.1)	
Increase in Idaho Power net income prior to effects of tax method changes and related examination settlements		58.7	
Net decrease in tax method changes and related examination settlements		(55.3)	
Total increase in Idaho Power net income			3.4
Other net decreases (net of tax)			(1.3)
Net income attributable to IDACORP, Inc. - December 31, 2012			$168.8

IDACORP's net income was $168.8 million in 2012, an increase of $2.1 million compared to 2011. IDACORP's 2012 results reflect an $86.3 million increase in operating income at Idaho Power compared to 2011, which was largely driven by increases in rates and higher irrigation sales volumes. This increase was substantially offset by the net impact of a tax method change and favorable IRS examination settlements recorded in 2011.

General rate increases implemented in the first quarter of 2012, a July 2012 rate increase related to Idaho Power's new Langley Gulch power plant, and other rate changes combined to increase operating income by $65.2 million when compared to 2011. Higher sales volumes, driven primarily by a warmer, drier spring in 2012 that caused significant increases in irrigation usage when compared with the prior year, increased operating income by $16.1 million. As a result of an IRS examination settlement reached in 2011, Idaho Power recognized approximately $56.9 million of previously unrecognized tax benefits related to a uniform capitalization method agreement with the IRS for tax years

2009 and prior.

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As a result of the impact on 2012 earnings of the rate and sales volume increases described above, Idaho Power recorded a total of $21.8 million related to a December 2011 settlement agreement with the IPUC, which required sharing with customers of a portion of 2012 Idaho-jurisdiction earnings exceeding a specified return on year-end equity. Of the total, $14.6 million was recorded as additional pension expense, which will benefit Idaho customers by reducing the amount of deferred pension expense that will need to be collected from customers in the future, and $7.2 million was recorded as a provision against current revenues to be refunded to customers through a future rate reduction. In 2011, Idaho Power recorded $20.3 million of additional pension expense and a $27.1 million provision against revenues to be refunded to customers under similar agreements. The table below summarizes the effect of the sharing mechanisms on operating income between 2012 and 2011.

Effect of Sharing on Operating Income

	2012	2011	Variance
Provision against current revenue as a result of sharing	$(7.2)	$(27.1)	$19.9
Additional pension expense funded through sharing	(14.6)	(20.3)	5.7
Total	$(21.8)	$(47.4)	$25.6

Key Operating and Financial Metrics for 2013

IDACORP's and Idaho Power's outlook for 2013 full year metrics as of the date of this report are as follows:

	2013 Estimate	2012 Actual
Idaho Power Operating & Maintenance Expense (millions)	$340-$350	$349
Idaho Power Additional Amortization of ADITC (millions)	Less than $5	None
Idaho Power Capital Expenditures, excluding AFUDC (millions)	$245-$255	$228
Idaho Power Hydroelectric Generation (million MWh)	6.0-8.0	8.0

The estimated hydroelectric generation range is based on reservoir storage levels and forecasted weather conditions as of the date of this report.

RESULTS OF OPERATIONS

This section of the MD&A takes a closer look at the significant factors that affected IDACORP's and Idaho Power's earnings during the year ended December 31, 2012. In this analysis, the results for 2012 are compared to 2011 and the results for 2011 are compared to 2010.

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

Utility Operations

The table below presents Idaho Power's energy sales, in MWh, and supply for the last three years.

	Year Ended December 31,		
	2012	2011	2010
General business sales	14,085	13,734	13,513
Off-system sales	2,183	3,635	1,982
Total energy sales	16,268	17,369	15,495
Hydroelectric generation	7,956	10,937	7,344
Coal generation	5,227	4,820	6,864
Natural gas and other generation	676	138	160
Total system generation	13,859	15,895	14,368
Purchased power	3,670	2,751	2,401
Line losses	(1,261)	(1,277)	(1,274)

Total energy supply	16,268	17,369	15,495

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Sales Volume and Generation: In 2012, general business sales volume increased by 0.4 million MWh, mostly related to increased irrigation customer usage compared to the prior year. Off-system sales volume decreased by 1.5 million MWh in 2012 as decreases in output from hydroelectric resources and a small increase in customer load decreased surplus power available for sale.

Hydroelectric generation comprised 57 percent of Idaho Power's total system generation during 2012. Hydroelectric generation in 2012 was 93 percent of the annual median generation of 8.6 million MWh, which is based on hydrologic conditions for the period 1928 through 2011 and adjusted to reflect the current level of water resource development. The 3.0 million MWh decrease in hydroelectric generation in 2012 compared to 2011 was primarily due to lower than normal hydroelectric generating conditions. The 3.6 million MWh increase in hydroelectric generation in 2011 compared to 2010 was due largely to favorable hydroelectric generating conditions.

The decrease in hydroelectric generation during 2012 led to an increased utilization of coal-fired and natural-gas fired generation. The commencement of operations of the Langley Gulch natural gas-fired power plant in the summer of 2012 allowed for less reliance on purchased power to replace the decreased hydroelectric generation.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. During 2012, 2011, and 2010, to reduce the magnitude of peak demands, Idaho Power utilized a number of demand response and energy efficiency programs. On July 12, 2012, Idaho Power achieved a record load demand of 3,245 MW. The highest winter peak demand of 2,527 MW was set on December 10, 2009. During these and other similar heavy load periods, Idaho Power's system is fully committed to serve loads and meet required operating reserves. When loads exceed Idaho Power's generation capacity, Idaho Power must rely on power obtained through purchase contracts (from which power may not be available when needed if the source is intermittent power such as wind) and may be required to purchase power in the wholesale energy spot market.

General Business Revenues: The table below presents Idaho Power's general business revenues, MWh sales, and number of customers for the past three years.

	Year Ended December 31,		
	2012	2011	2010
Revenue			
Residential	$431,555	$405,982	$400,607
Commercial	241,519	220,962	231,440
Industrial	145,054	140,701	138,394
Irrigation	137,424	104,635	110,555
Total	955,552	872,280	880,996
Provision for sharing	(7,151)	(27,099)	—
Deferred revenues [1]	(10,636)	(10,636)	(10,625)
Total general business revenues	$937,765	$834,545	$870,371
MWh			
Residential	5,039	5,146	4,967
Commercial	3,865	3,815	3,763
Industrial	3,133	3,100	3,076
Irrigation	2,048	1,673	1,707
Total	14,085	13,734	13,513
Customers at year-end			
Residential	416,020	411,487	408,754
Commercial	65,920	65,226	64,647
Industrial	119	121	125
Irrigation	19,045	18,736	18,547

Total	501,104	495,570	492,073

(1) As part of its January 30, 2009 general rate case order, the IPUC allowed Idaho Power to recover AFUDC for the HCC relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. Idaho Power expects to collect approximately $10.7 million annually in the Idaho jurisdiction, but will defer revenue recognition of the amounts collected until the license is issued and the asset is placed in service.

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Changes in rates and changes in customer demand are the primary causes of fluctuations in general business revenue. The table below presents the most significant rate increases and decreases, shown on an annualized basis, that impacted revenues over the last three years.

Description	Effective Date	Estimated Annualized $ Impact (millions)
2010 Idaho settlement agreement	6/1/2010	89
2010 Idaho PCA	6/1/2010	(147)
2010 Idaho pension expense recovery	6/1/2010	5
2011 Idaho PCA	6/1/2011	(40)
2011 Idaho pension expense recovery	6/1/2011	12
2011 Idaho general rate case settlement agreement	1/1/2012	34
2012 Idaho PCA	6/1/2012	43
2012 Idaho non-AMI meter depreciation	6/1/2012	(11)
2012 Idaho Langley Gulch	7/1/2012	58
2012 Oregon Langley Gulch	10/1/2012	3

The primary influences on customer demand are weather 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, with increased precipitation reducing electricity usage. Rates are also seasonally adjusted and based on a tiered rate structure that provides for higher rates during peak load periods. These seasonal and tiered rate structures contribute to seasonal fluctuations in revenues and earnings. Boise, Idaho weather-related information for the last three years is included in the table that follows.

	Year Ended December 31,			
	2012	2011	2010	Normal
Heating degree-days [1]	4,723	5,554	5,078	5,514
Cooling degree-days [1]	1,274	1,076	914	942

[1] Heating and cooling degree-days are common measures 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.

General Business Revenues - 2012 Compared to 2011: General business revenue increased $103.2 million in 2012 compared to 2011. The factors affecting general business revenues are discussed below.

- Rates. Rate changes, including those shown in the table above, combined to increase general business revenue by $73.5 million in 2012 compared to 2011. The revenue impact of several of these rate changes was directly offset by associated changes in operating expenses. For example, Idaho-jurisdiction pension expense recovery rate changes were fully offset by increased pension expense.

- Sharing. A part of the increase in 2012 revenue resulted from revenue sharing mechanisms associated with two Idaho regulatory agreements that provide for the sharing of Idaho-jurisdiction earnings exceeding a specified Idaho ROE. The amount to be shared through future rate reduction is recorded as a current reduction to general business revenue. Reductions of $7.2 million and $27.1 million were recorded in 2012 and 2011, respectively, resulting in a net increase to general business revenue of $19.9 million in 2012. The smaller amount recorded in 2012 when compared with the prior year is partially due to changes in the terms of the mechanism in place each year, described in

"Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

• Usage. For 2012, higher summer usage per customer increased general business revenue $13.7 million compared to 2011. Irrigation usage per customer was 20.9 percent higher for 2012 when compared with 2011 due to agricultural growing conditions, including warm temperatures that allowed for the earlier planting of crops, and lower relative springtime precipitation, which resulted in greater electricity use to operate irrigation pumps.

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- Customers. Termination of service to Hoku Materials, Inc. (Hoku) during 2012 under an electric service agreement, offset by only moderate customer growth, decreased general business revenues by $3.9 million. Customer growth from 2011 to 2012 was 1.1 percent.

In March 2009, the IPUC approved an electric service agreement between Idaho Power and Hoku, to provide electric service to Hoku's polysilicon production facility then under construction in Idaho. The initial term of the agreement was four years beginning December 1, 2009, with a maximum demand obligation during the initial term of 82 MW. In connection with an overdue invoice for electric service, in February 2012 Idaho Power, Hoku, and the IPUC Staff filed with the IPUC a settlement stipulation to amend the electric service agreement, and on March 15, 2012, the IPUC approved the stipulation revising the contract. As a result of Hoku's failure to remain timely in payments under the revised agreement, Idaho Power terminated its provision of electric service under the revised agreement in May 2012. Idaho Power applied a $2 million deposit to Hoku's April, May, and June 2012 invoices under the revised agreement and fully exhausted the deposit required by the revised agreement. For full year 2012 and prior to termination of service, Idaho Power had anticipated contract payments of $5.4 million that are unaffected by the PCA mechanism and $6.8 million of revenues that are affected by and flow through the PCA mechanism, for a total of $12.2 million. As a result of termination of service and non-payment, Idaho Power recognized $6.6 million of full year 2012 revenues that are unaffected by the PCA mechanism and no revenues that are affected by and flow through the PCA mechanism. The impact of non-payment and associated decreases in revenue on 2012 net income was tempered in part by a decrease in costs Idaho Power would have incurred in connection with the provision of service to Hoku and the impact of the PCA mechanism.

General Business Revenues - 2011 Compared to 2010: General business revenue decreased $35.8 million in 2011 compared to 2010. The factors affecting general business revenues are discussed below.

- Rates. Rate changes noted in the table above combined to reduce general business revenue by $38.8 million in 2011 as compared to 2010. The $10.5 million decline in revenue from commercial customers in 2011 relative to 2010, notwithstanding an increase in usage, was largely due to the disproportionate impact of the PCA rate reductions that went into effect in 2010 and 2011. Commercial customer rates are typically subject to a greater adjustment when PCA rates increase or decrease.

- Sharing. Much of the decrease in 2011 revenue resulted from revenue sharing mechanisms associated with Idaho regulatory agreements that provide for the sharing of Idaho-jurisdiction earnings exceeding a specified Idaho ROE. The amount shared through rate reduction was recorded as a reduction to general business revenue. A reduction of $27.1 million was recorded in 2011. No such amount was recorded in 2010.

- Usage. Higher usage per customer in 2011 increased general business revenue $13.5 million compared to 2010. The increase was due primarily to colder first quarter temperatures, which increased power demand for residential heating purposes, as well as a 17.7 percent increase in cooling degree-days during the year, which increased power demand for air conditioning purposes. This increase was partially offset by a 2.3 percent decrease in irrigation usage resulting from the cooler spring weather and the timing and level of precipitation during the second quarter of 2011.

- Customers. Changes related to the Hoku contract discussed above, along with a small increase in customer count, increased general business revenues by $16.6 million. Customer growth from 2010 to 2011 was 0.7 percent.

Off-System Sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The table below presents Idaho Power's off-system sales for the last three years.

	Year Ended December 31,		
	2012	2011	2010
Revenue	$61,534	$101,602	$78,133

MWh sold	2,183	3,635	1,982
Revenue per MWh	$28.19	$27.95	$39.42

Off-System Sales - 2012 Compared to 2011: Off-system sales revenue decreased by $40.1 million, or 39 percent, in 2012 as compared to 2011, as a result of lower volumes. Sales volumes decreased by 40 percent due to lower output from hydroelectric plants (as a result of less favorable snow pack and spring season run-off) and a small increase in load needs when compared with 2011.

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Off-System Sales - 2011 Compared to 2010: Off-system sales revenue increased $23.5 million, or 30 percent, in 2011 as compared to 2010. Sales volumes nearly doubled, as increases in output from hydroelectric and PURPA resources increased surplus power available for sale. This increase was partially offset by a 29 percent decrease in average prices due in part to abundant hydroelectric generation in the region.

Other Revenues: The table below presents the components of other revenues for the last three years.

	Year Ended December 31,		
	2012	2011	2010
Transmission services, facility rental and other	$50,126	$48,918	$40,364
Energy efficiency	27,300	37,663	44,184
Total	$77,426	$86,581	$84,548

Other Revenues - 2012 Compared to 2011: Other revenues decreased $9.2 million in 2012 as compared to 2011, mainly due to:

- a decrease in energy efficiency revenues of $10.4 million, primarily due to demand response incentive payments to customers, which had been treated as an energy efficiency expense and recovered through the energy efficiency rider in 2011 and prior, were recorded as purchased power expense and recovered through the PCA mechanism during 2012, as discussed in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report; and
- an increase of $1.7 million in transmission system revenues, resulting principally from increases in wheeling services attributable to increases in FERC transmission rates that took effect on October 1, 2011 and October 1, 2012.

Energy efficiency activities are funded through a rider mechanism on customer bills. Energy efficiency program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. A liability balance indicates that Idaho Power has collected more than it has spent and an asset balance indicates that Idaho Power has spent more than it has collected.

Other Revenues - 2011 Compared to 2010: Other revenues increased $2.0 million in 2011 as compared to 2010, mainly due to:

- an increase of $7.4 million in transmission system revenues, resulting principally from increases in wheeling services attributable to increases in FERC transmission rates that took effect on October 1, 2010 and 2011, and from other facility rental increases; and
- a decrease in energy efficiency revenues of $6.5 million, due in part to an IPUC order that moved custom efficiency payments to a regulatory asset to be amortized over time and recovered through general rate cases rather than through the energy efficiency rider. The remaining decrease relates to lower customer incentives paid versus the prior year.

Purchased Power: The table below presents Idaho Power’s purchased power expenses and volumes for the last three years.

	Year Ended December 31,		
	2012	2011	2010
Expense			
PURPA contracts	$117,618	$90,251	$56,022
Other purchased power (including wheeling)	79,317	73,085	87,747
Total purchased power expense	$196,935	$163,336	$143,769

MWh purchased			
PURPA contracts	1,961	1,495	910
Other purchased power	1,709	1,256	1,491
Total MWh purchased	3,670	2,751	2,401
Cost per MWh from PURPA contracts	$59.98	$60.36	$61.56
Cost per MWh from other sources	$46.41	$58.19	$58.85
Weighted average - all sources	$53.66	$59.37	$59.88

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The purchased power cost per MWh often exceeds the off-system sales revenue per MWh because Idaho Power generally needs to purchase more power during heavy load periods, which is higher priced energy, than during light load periods, which is lower priced energy, and conversely has less energy available for off-system sales during heavy load periods than light load periods. Also, in accordance with Idaho Power's risk management policy, Idaho Power may purchase or sell energy several months in advance of anticipated delivery. The regional energy market price is dynamic and additional energy purchase or sale transactions that Idaho Power makes at current market prices may be noticeably different than the advance purchase or sale transaction prices.

Purchased Power - 2012 Compared to 2011: Purchased power expense increased $33.6 million, or 21 percent, in 2012 as compared to 2011, principally due to additional PURPA wind generation that came on-line and less favorable hydroelectric generating conditions. MWh purchased through PURPA contracts increased 31 percent, contributing to a $27.4 million increase in PURPA power purchase expense in 2012 compared to 2011, while MWh purchased through other sources increased 36 percent. Overall MWh purchases increased due to less favorable hydroelectric generating conditions decreasing Idaho Power's volume of self-generated power. The increase in MWh purchased was partially offset by a reduction in expense per MWh purchased. Average wholesale electricity prices were lower in 2012 relative to 2011 as a result of lower natural gas prices in the region, which reduced generation costs and, correspondingly, power prices. In addition, $14.5 million of demand response program charges were recorded as purchased power expense in 2012. These costs had been treated as an energy efficiency expense and recovered through the energy efficiency rider in 2011 and prior.

Purchased Power - 2011 Compared to 2010: Purchased power expense increased $19.6 million, or 14 percent, in 2011 as compared to 2010. This increase was driven by MWh purchased from PURPA contracts, which increased 64 percent due to new PURPA wind generation facilities coming on-line. The increase was partially offset by reduced wholesale market purchases resulted from Idaho Power's above average hydroelectric generation in 2011, and continued reliance on financial hedges to mitigate potential changes in forecasted hydroelectric conditions. Wholesale market purchases were also down due to lower system loads resulting from relatively mild weather.

Fuel Expense: Idaho Power's fuel expenses and generation at its thermal generating plants for the last three years are included in the table below.

	Year Ended December 31,		
	2012	2011	2010
Expense			
Coal	$134,501	$119,845	$146,927
Natural gas and other	24,912	11,697	12,746
Total fuel expense	$159,413	$131,542	$159,673
MWh generated			
Coal	5,227	4,820	6,864
Natural gas and other	676	138	160
Total MWh generated	5,903	4,958	7,024
Cost per MWh			
Coal	$25.73	$24.86	$21.41
Natural gas and other	36.85	84.76	79.66
Weighted average, all sources	27.01	26.53	22.73

Most fuel supply contracts are subject to changes in published indexes that are closely related to materials and supplies, labor, and diesel costs. In addition to commodity (variable) costs, both natural gas and coal expense include costs that are more fixed in nature for items such as capacity charges, transportation, and fuel handling. Period to period variances in fuel expense per MWh (such as the cost per MWh for natural gas and other in 2012 compared to 2011 and 2010) are noticeably impacted by these fixed charges when generation output is substantially different between the two periods.

Fuel Expense - 2012 Compared to 2011: In 2012, fuel expense increased $27.9 million, or 21 percent, compared to 2011, due to higher output at the coal-fired power plants and at the Langley Gulch plant, which came on-line during the summer of 2012. The output at the coal-fired plants was up 0.4 million MWh, or 8 percent, in 2012 compared to 2011. The increased dispatch was primarily caused by lower hydroelectric generation in 2012 than in 2011.

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Fuel Expense - 2011 Compared to 2010: In 2011, fuel expense decreased $28.1 million, or 18 percent, compared to 2010 due to lower generation at Idaho Power's thermal plants. The output at these plants was down 2.0 million MWh, or 30 percent in 2011 compared to 2010. The reduced dispatch was primarily caused by lower regional power prices due to higher regional hydroelectric and wind generation. The impact of lower thermal generation was partially offset by higher coal prices. During parts of 2010, the Bridger and Valmy generating plants received fuel from prior lower-cost contracts.

PCA Mechanisms: Idaho Power's power supply costs can vary significantly from year to year, primarily because of the impacts of weather, system loads, and commodity markets. To address the volatility of power supply costs, in addition to its hedging program Idaho Power has PCA mechanisms for both the Idaho and Oregon jurisdictions. These mechanisms allow Idaho Power to recover from or refund to customers most of the fluctuations in power supply costs. Because of these mechanisms, the primary financial impacts of power supply cost variations is that cash is paid out but recovery from customers does not occur until a future period, or cash that is collected is refunded to customers, resulting in fluctuations in operating cash flows from year to year. PCA expense represents the effects of the Idaho and Oregon PCA mechanisms. The table below presents the components of the Idaho and Oregon PCA mechanisms for the last three years.

	Year Ended December 31,		
	2012	2011	2010
Idaho power supply cost (deferral) accrual	$(45,064)	$27,768	$(14,324)
Oregon power supply cost (deferral) accrual	(1,523)	1,523	—
Amortization to expense of prior year authorized balances	(14,503)	9,206	65,550
Total power cost adjustment expense	$(61,090)	$38,497	$51,226

The power supply accruals or deferrals represent the portion of that period's power supply cost fluctuations accrued or deferred under the PCA mechanisms. Accruals represent additional costs being recorded as a result of actual power supply costs that were less than the amount forecasted in PCA rates. The power supply cost is a deferral in 2012 because actual power supply costs in 2012 were higher than the amounts forecasted in PCA rates. If actual power supply costs are greater than the amount forecasted in PCA rates, the majority of the excess is deferred. The amortization of the prior year's balances represents the amounts being collected (refunded) in the current PCA year that were deferred or accrued in the prior PCA year (the true-up component of the PCA).

PCA Mechanisms - 2012 Compared to 2011: Actual net power supply costs increased in 2012 relative to 2011, resulting in a change of $75.9 million—from accruals of $29.3 million to deferrals of $46.6 million. The $14.5 million of amortization reflects the net refunding to customers of prior years' accruals.

PCA Mechanisms - 2011 Compared to 2010: Actual net power supply costs decreased in 2011 relative to 2010, resulting in a change of $43.6 million—from a deferral of $14.3 million to an accrual of $29.3 million. For 2011, net collections on previously deferred amounts have decreased due to lower PCA true-up rates, reducing the PCA amortization by $56.3 million.

Other Operations and Maintenance Expenses: An explanation of the changes in operations and maintenance expenses for the periods presented is below.

O&M - 2012 Compared to 2011: A $10.4 million increase in other O&M expense in 2012 as compared to 2011 was principally due to:

- $9.0 million in higher administrative expenses related to various increases in consultant costs, software licenses and maintenance, insurance reserves, and other purchased services. A significant portion of the increase related to a lower reimbursement from the U.S. Department of Energy (DOE) for Smart Grid-related items in 2012 compared to 2011;

- increased payroll and other benefit expenses of $6.8 million related to normal increases in employee wages and costs of providing employee benefits; and
- a $3.2 million increase in transmission system maintenance expenses primarily related to line inspection costs; offset by
- a $9.1 million decrease in thermal plant O&M related to costs for maintenance outages that occurred in 2011 that did not recur in 2012, as well as lower overall maintenance costs and consumable supplies due to lower utilization of these plants during the first half of 2012. The lower utilization was predominantly driven by low wholesale energy prices in the region during that period.

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O&M - 2011 Compared to 2010: The $44.7 million increase in other O&M expense in 2011 as compared to 2010 was principally due to:

- $20.3 million of increased pension expenses relating to the settlement stipulation that reduced a portion of Idaho customers' future obligation through a reduction in the pension regulatory asset;
- increased pension and other benefit expenses of $11.5 million, primarily due to pension expense amortization that began in June 2010 and was increased in June 2011 in conjunction with recovery of deferred pension costs in rates;
- $5.0 million in higher thermal O&M due to maintenance outages at the Valmy plant, partially offset by an equipment impairment taken in 2010 at the Bridger plant that did not recur in 2011; and
- an increase in other payroll related costs of $5.7 million; offset by
- a combination of lower meter reading expense and the completed amortization of certain DSM expenses of $3.5 million, and lower outside service fees of $2.3 million.

Income Taxes

Income Tax Expense: IDACORP's and Idaho Power's income tax expense for 2012 increased significantly relative to 2011, primarily as a result of greater pre-tax earnings in 2012 and the tax benefits from IRS examination settlements recorded in 2011. Income tax expense in 2011 decreased significantly compared to 2010, principally as a result of an IRS examination settlement in 2011 related to Idaho Power's uniform capitalization tax accounting method. For additional information relating to IDACORP's and Idaho Power's income taxes, see Note 2 - “Income Taxes” to the consolidated financial statements included in this report.

Bonus Depreciation: The Small Business Jobs Act (Jobs Act) and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) include provisions for the extension and increase of bonus depreciation. Bonus depreciation provides for the accelerated deduction of current capital expenditures from certain asset classes. The Jobs Act extended 50 percent bonus depreciation to 2010 and the Tax Relief Act extended bonus depreciation to 2011-2012 and increased it to 100 percent for a portion of 2010 and 2011. In addition, the American Taxpayer Relief Act of 2012 extended 50 percent bonus depreciation to 2013. Idaho Power has included an estimated bonus deprecation deduction in its current income tax provision. The estimated deduction would reduce Idaho Power's 2012 federal income tax liability by approximately $81 million. Idaho Power is evaluating the impacts the extension of bonus depreciation could have on its 2013 income taxes. The state of Idaho did not conform to the federal bonus depreciation rules for 2010-2013.

Net Operating Loss and Tax Credit Carryforwards: IDACORP finished 2012 with a federal net operating loss carryforward of $156 million, a federal general business tax credit carryforward of $107 million, and a $38 million Idaho investment tax credit carryforward. Based on the expiration dates of the credits, as described in Note 2 - "Income Taxes - Tax Credit Carryforwards and Net Operating Loss Carryforwards" to the consolidated financial statements included in this report, these amounts are expected to provide future cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Overview

IDACORP's and Idaho Power's operating cash flows are driven principally by Idaho Power's sales of electricity and transmission capacity. Significant uses of cash flows from operations include the purchase of fuel and power, other operating expenses, capital expenditures, pension plan contributions, and interest. Operating cash flows can be significantly influenced by factors such as weather conditions, rates and the outcome of regulatory proceedings, and economic conditions. As fuel and purchased power are significant uses of cash, and at the same time their prices can be volatile and difficult to predict, Idaho Power has regulatory mechanisms in place that provide for the deferral and recovery of the majority of the fluctuation in those costs. However, if actual costs rise above the level allowed in retail rates, deferral balances increase (reflected as a regulatory asset), negatively affecting operating cash flows until such time as those costs, with interest, are recovered from customers. Idaho Power uses operating and capital budgets to control operating costs and optimize capital expenditures, and funds its liquidity needs for capital expenditures through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. Idaho Power seeks to recover its operating costs and earn a return on its capital expenditures through rates, periodically filing for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align Idaho Power's earned returns with those allowed by regulators.

Idaho Power continues to make significant infrastructure investments. During 2012 Idaho Power added capacity to its baseload generation through the completion of construction of the Langley Gulch power plant. Idaho Power has also been pursuing

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significant transmission system enhancements and upgrading distribution facilities in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Additionally, Idaho Power's aging hydroelectric and thermal generation facilities require continuing upgrades and component replacement, and the costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. Idaho Power estimates that total capital expenditures will be between $815 million and $835 million over the period from 2013 through 2015. A significant focus for 2013 will be to control costs and generate sufficient cash from operations to meet operating needs, contribute to capital expenditure requirements, and pay dividends to shareholders.

As of February 15, 2013, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- their respective $125 million and $300 million revolving credit facilities;
- IDACORP's shelf registration statement, which it may use for the issuance of debt securities and common stock, including up to 3.0 million shares of IDACORP common stock available for issuance under its continuous equity program. Approximately $539 million of debt and equity securities issuances remained available under the shelf registration statement;
- Idaho Power's shelf registration statement, which it may use for the issuance of first mortgage bonds and debt securities; $150 million remained available under the shelf registration statement, which expires in May 2013; and
- IDACORP's and Idaho Power's issuance of commercial paper, which may be issued up to an amount equal to the available credit capacity under their respective credit facilities, and is used to meet short-term liquidity requirements.

IDACORP and Idaho Power monitor capital markets with a view toward opportunistic debt and equity transactions where possible in light of future needs. To meet maturing long-term debt obligations and costs of infrastructure development, such as Idaho Power's 500-kV transmission projects, the companies may use a combination of internally generated funds, credit facilities, the issuance of long-term debt or equity and, in the case of Idaho Power, capital contributions from IDACORP. IDACORP and Idaho Power expect to continue financing capital requirements during 2013 with a combination of internally generated funds and externally financed capital, and believe that access to their credit facilities and commercial paper, operating cash flows generated by Idaho Power's utility business, and ability to issue medium-term notes will be sufficient to meet short-term obligations and debt maturities in 2013. Idaho Power has $70 million of first mortgage bonds due in October 2013, with no first mortgage bonds due thereafter until 2018. IDACORP and Idaho Power expect a minimal need for any additional external financing in 2013, other than for the repayment of the first mortgage bonds due in October 2013 and issuances of commercial paper to meet cash balancing needs from time-to-time.

Effective July 1, 2012, IDACORP discontinued original issuances of common stock and instructed the plan administrators to use market purchases of IDACORP common stock for purposes of acquiring IDACORP common stock for the IDACORP, Inc. Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan. However, IDACORP may determine at any time to resume original issuances of common stock under those plans. IDACORP may also determine to issue common stock from time-to-time under its continuous equity program, depending on market conditions and capital needs. An important component of that determination will be IDACORP's and Idaho Power's capital structure. IDACORP and Idaho Power seek to maintain capital structures of approximately 50 percent debt and 50 percent equity, and maintaining this ratio influences IDACORP's and Idaho Power's debt and equity issuance decisions. As of December 31, 2012, IDACORP's and Idaho Power's capital structures were as follows:

	IDACORP	Idaho Power
Debt	48%	49%
Equity	52%	51%

Operating Cash Flows

IDACORP’s and Idaho Power’s operating cash inflows for the year ended December 31, 2012 were $249 million and $258 million, respectively. IDACORP's operating cash flows decreased by $61 million and Idaho Power's decreased by $35 million compared to the year ended December 31, 2011. With the exception of cash flows related to income taxes, IDACORP’s operating cash flows are principally derived from the operating cash flows of Idaho Power. Significant items that affected the companies' operating cash flows in 2012 relative to 2011 included:

- Idaho Power made contributions of $44.3 million to its defined benefit pension plan in 2012, compared with a $18.5 million cash contribution in 2011;

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- cash outflows related to income taxes increased by $14 million for IDACORP, while cash inflows related to income taxes increased by $14 million for Idaho Power. IDACORP paid income taxes of $1 million in 2012 compared with receiving $12 million of income tax refunds in 2011. Idaho Power’s net refunds from IDACORP for income tax were $15 million for 2012, compared with $1 million for 2011;
- changes in regulatory assets associated with the Idaho and Oregon PCA mechanisms reduced cash flows by $100 million, as Idaho Power collected $24 million less of previously deferred costs due to decreases in PCA rates and incurred $76 million less in the current year PCA accrual, as compared with 2011; and
- Idaho Power's joint venture, BCC, made net distributions to Idaho Power of $18 million for 2012, as compared to a $3 million net contribution for 2011. The change from year to year is the result of BCC having more cash to distribute in 2012 than 2011. There were less capital investments in 2012 than 2011, less operating cash invested in coal inventory in 2012 than 2011, and higher reclamation activities in 2012 than 2011 causing an increase in the amount of disbursements from the reclamation trust to BCC.

IDACORP's and Idaho Power's operating cash inflows for the year ended December 31, 2011 were $310 million and $292 million, respectively. IDACORP's operating cash flows increased by $5 million and Idaho Power's decreased by $38 million compared to the year ended December 31, 2010. Significant items that affected operating cash flows in 2011 included:

- income before income taxes decreased by $27 million for IDACORP and $28 million for Idaho Power;
- in 2011, Idaho Power recorded a $27 million regulatory liability in addition to a $20 million reduction to pension-related regulatory assets as a result of sharing mechanisms, which reduced income before income taxes but did not reduce operating cash flows. No sharing was recorded during 2010;
- cash outflows related to the pension and postretirement benefit plans decreased by $44 million. Idaho Power made an $18.5 million cash contribution to its defined benefit pension plan in 2011, compared with a $60 million cash contribution in 2010;
- cash inflows related to income taxes decreased by $15 million and $57 million for IDACORP and Idaho Power, respectively. IDACORP received income tax refunds of $12 million in 2011 compared with $27 million in 2010. Idaho Power’s net refunds from IDACORP for income tax were $1 million for 2011, compared with $57 million for the same period in 2010;
- changes in regulatory assets associated with the Idaho and Oregon PCA mechanisms reduced cash flows by $13 million, as Idaho Power collected $56 million less of previously deferred costs due to decreases in PCA rates, partially offset by a $44 million increase in the 2011 PCA accrual, as compared with 2010;
- changes in fuel inventories reduced operating cash flows by $18 million, as fuel on hand increased by $20 million during 2011 due to decreased thermal plant operation, compared with $2 million during the same period in 2010; and
- differences in the timing of collections due to changes in retail accounts receivable and unbilled revenue balances decreased cash flows by $10 million, as Idaho Power collected more during 2010 than it recorded as revenues while collecting less during 2011 than it recorded as revenues.

Investing Cash Flows

Investing activities are predominantly related to capital expenditures for new construction and improvements to Idaho Power's generation, transmission, and distribution facilities. These capital expenditures address peak demand growth, aging plant and equipment, and customer growth. Idaho Power's construction expenditures were $240 million, $338 million, and $338 million in 2012, 2011, and 2010, respectively. Construction expenditures during the periods were heavily impacted by construction costs for the Langley Gulch power plant. In 2010, construction expenditures were partially offset by proceeds from the sale of $19 million of transmission-related assets to PacifiCorp. IDACORP cash flows relating to investments in affordable housing through IFS were $0.1 million, $2 million, and $13 million in 2012, 2011, and 2010, respectively.

Financing Cash Flows

Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. Idaho Power funds liquidity needs for capital investment, working capital, energy and price hedging, and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets, credit facilities, and contributions from IDACORP. IDACORP funds its cash requirements, such as payment of taxes, capital contributions to Idaho

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Power, and non-utility expenses allocated to IDACORP, through cash flows from operations, commercial paper markets, sales of common stock, and credit facilities.

Debt: On June 17, 2010, Idaho Power entered into a Selling Agency Agreement with Banc of America Securities LLC; BNY Mellon Capital Markets, LLC; J.P. Morgan Securities Inc.; KeyBanc Capital Markets Inc.; Merrill Lynch, Pierce, Fenner & Smith Incorporated; Mitsubishi UFJ Securities (USA), Inc.; RBC Capital Markets Corporation; SunTrust Robinson Humphrey, Inc.; U.S. Bancorp Investments, Inc.; and Wells Fargo Securities, LLC in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds under a shelf registration statement.

On August 30, 2010, Idaho Power issued $100 million of 3.40% first mortgage bonds, Series I due 2020 and $100 million of 4.85% first mortgage bonds, Series I due 2040 under a shelf registration statement. On March 2, 2011, Idaho Power repaid at maturity $120 million of its 6.60% first mortgage bonds (secured notes) using a portion of the proceeds from the first mortgage bonds issued in August 2010. On April 13, 2012, Idaho Power issued $75 million of 2.95% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2022 and $75 million of 4.30% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2042, under the Selling Agency Agreement and shelf registration statement. In April 2012, Idaho Power issued an irrevocable notice of redemption to redeem, prior to maturity, its $100 million in principal amount of 4.75% first mortgage bonds, medium-term notes due November 2012. In May 2012, Idaho Power used a portion of the net proceeds of the April 2012 issuance of first mortgage bonds, medium-term notes to effect the redemption. Idaho Power's next upcoming material long-term debt principal repayment obligation is its $70 million of 4.25% first mortgage bonds that mature in October 2013.

Equity: IDACORP has entered into sales agency agreements as a means of selling its common stock from time to time in at-the-market offerings. IDACORP did not issue any shares under these agreements in 2012 or 2011. In 2010, IDACORP received $34 million, net of agent's fees, from the issuance of 973,585 shares of IDACORP common stock at an average price of $35.47. IDACORP entered into a new sales agency agreement with BNY Mellon Capital Markets, LLC on December 16, 2011, replacing a December 2008 sales agency agreement that provided for the sale of up to 3 million shares of IDACORP common stock. At the time of expiration of the December 2008 sales agency agreement in December 2011, 1,165,233 shares were unissued. As of February 15, 2013, 3 million shares remained available for issuance under the current sales agency agreement.

During the first half of 2012, IDACORP continued to issue common stock under the pre-existing dividend reinvestment and employee-related stock purchase plans. Effective July 1, 2012, IDACORP discontinued original issuances of common stock and instructed the plan administrators to use market purchases for purposes of acquiring IDACORP common stock for the IDACORP, Inc. Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan. Under these plans, IDACORP issued 111,380 shares in 2012, 211,276 shares in 2011, and 250,030 shares in 2010, for proceeds of $4.5 million, $8.2 million, and $8.6 million, respectively.

IDACORP issued 8,600 shares of IDACORP common stock in 2012, 255,746 shares in 2011, and 194,860 shares in 2010, in connection with the exercise of stock options, for proceeds of $0.4 million, $9.4 million, and $5.4 million, respectively.

IDACORP and Idaho Power paid dividends of $69 million, $60 million, and $58 million in 2012, 2011, and 2010, respectively. IDACORP made capital contributions of $8 million, $16 million, and $50 million to Idaho Power in 2012, 2011, and 2010, respectively.

Financing Programs

Shelf Registrations: IDACORP has an effective shelf registration statement that, as of the date of this report, can be used for the issuance of up to $539 million of debt securities and common stock. Idaho Power has an effective registration statement that, as of the date of this report, can be used for the issuance of up to $150 million of first mortgage bonds and unsecured debt.

The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. Future issuances of first mortgage bonds are subject to satisfaction of covenants and security provisions set forth in the Indenture of Mortgage and Deed of Trust, market conditions, regulatory authorizations, and covenants contained in other financing agreements. The Indenture of Mortgage and Deed of Trust limits the amount of additional first mortgage bonds that Idaho Power may issue to the sum of (a) the principal amount of retired first mortgage bonds and (b) 60 percent of total unfunded property additions, as defined in the Indenture of Mortgage and Deed of Trust. As of December 31, 2012, Idaho Power could issue approximately $1.4 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. However, the Indenture of Mortgage and

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Deed of Trust further limits the maximum amount of first mortgage bonds at any one time outstanding to $2.0 billion, and as a result the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2012 was limited to approximately $489 million. Idaho Power may increase the $2.0 billion limit on the maximum amount of first mortgage bonds outstanding by filing a supplemental indenture with the trustee as provided in the Indenture of Mortgage and Deed of Trust.

Refer to Note 4 - “Long-Term Debt” to the consolidated financial statements included in this report for more information regarding long-term financing arrangements.

Credit Facilities: IDACORP and Idaho Power have $125 million and $300 million credit facilities, respectively. Each of the credit facilities may be used for general corporate purposes and commercial paper back-up. IDACORP's facility permits borrowings under a revolving line of credit of up to $125 million at any one time outstanding, including swingline loans not to exceed $15 million at any time and letters of credit not to exceed $50 million at any time. IDACORP's facility may be increased, subject to specified conditions, to $150 million. Idaho Power's facility permits borrowings through the issuance of loans and standby letters of credit of up to $300 million at any one time outstanding, including swingline loans not to exceed $30 million at any one time. Idaho Power's facility may be increased, subject to specified conditions, to $450 million. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. The companies also pay a facility fee based on the respective company's credit rating for senior unsecured long-term debt securities.

Each facility contains a covenant requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization equal to or less than 0.65 as of the end of each fiscal quarter. In determining the leverage ratio, “consolidated indebtedness” broadly includes all indebtedness of the respective borrower and its subsidiaries, including, in some instances, indebtedness evidenced by certain hybrid securities (as defined in the credit agreement). “Consolidated total capitalization” is calculated as the sum of all consolidated indebtedness, consolidated stockholders' equity of the borrower and its subsidiaries, and the aggregate value of outstanding hybrid securities. At December 31, 2012, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. IDACORP's and Idaho Power's ability to utilize the credit facilities is conditioned upon their continued compliance with the leverage ratio covenants included in the credit facilities, which could limit the ability of the companies to issue first mortgage bonds and debt securities. There are additional covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments, restrict the creation of certain liens, and prohibit entering into any agreements restricting dividend payments from any material subsidiary. At February 15, 2013, IDACORP and Idaho Power were in compliance with all facility covenants. Further, IDACORP and Idaho Power do not believe they will be in violation or breach of their respective debt covenants during 2013, but were circumstances to arise that may alter that view management would take appropriate action to mitigate any such issue.

The events of default under both facilities include, without limitation, non-payment of principal, interest, or fees; materially false representations or warranties; breach of covenants; bankruptcy or insolvency events; condemnation of property; cross-default to certain other indebtedness; failure to pay certain judgments; change of control; failure of IDACORP to own free and clear of liens the voting stock of Idaho Power; the occurrence of specified events or the incurring of specified liabilities relating to benefit plans; and the incurring of certain environmental liabilities, subject, in certain instances, to cure periods.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or Idaho Power or the appointment of a receiver, the obligations of the lenders to make loans under the applicable facility and 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 greater than 50 percent of the outstanding loans or greater than 50 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 to issue letters of credit under the facility and/or declare the obligations to be due and payable. During an event of default under the facilities, the lenders may, at their option, increase the applicable interest rates then in effect and the letter of credit fee by 2.0 percentage points per annum. A ratings downgrade would result in an increase in the cost of borrowing, but would not result in a default or acceleration of the debt under the facilities. However, if Idaho Power's ratings are downgraded below investment grade, Idaho Power must extend or renew its authority for borrowings under its IPUC and OPUC regulatory orders.

While the credit facilities provide for an original maturity date of October 26, 2016, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, in each case subject to certain conditions. On October 12, 2012, IDACORP and Idaho Power executed First Extension Agreements with each of the lenders, extending the maturity date under

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both agreements to October 26, 2017. No other terms of the credit agreements, including the amount of permitted borrowings under the credit agreements, were affected by the extension.

Without additional approval from the IPUC, the OPUC, and the Public Service Commission of Wyoming, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

Commercial Paper: IDACORP and Idaho Power have commercial paper programs under which they may issue unsecured commercial paper notes up to a maximum aggregate amount outstanding at any time not to exceed the available capacity under their respective credit facilities, described above. IDACORP's and Idaho Power's credit facilities are available to the companies to support borrowings under their commercial paper programs. The commercial paper issuances are used to provide an additional financing source for the companies' short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Individual instruments carry a fixed rate during their respective terms, although the interest rates are reflective of current market conditions, subjecting the companies to fluctuations in interest rates.

Available Short-Term Liquidity: The following table outlines available short-term borrowing liquidity as of the dates specified.

	December 31, 2012		December 31, 2011	
	IDACORP[2]	Idaho Power	IDACORP[2]	Idaho Power
Revolving credit facility	$125,000	$300,000	$125,000	$300,000
Commercial paper outstanding	(69,700)	—	(54,200)	—
Identified for other use[1]	—	(24,245)	—	(24,245)
Net balance available	$55,300	$275,755	$70,800	$275,755

(1) Port of Morrow and American Falls bonds that Idaho Power could be required to purchase prior to maturity under the optional or mandatory purchase provisions of the bonds, if the remarketing agent for the bonds were unable to sell the bonds to third parties.
(2) Holding company only.

At February 15, 2013, IDACORP had no loans outstanding under its credit facility and $64.0 million of commercial paper outstanding, and Idaho Power had no loans outstanding under its credit facility and no commercial paper outstanding. The table below presents additional information about short-term commercial paper borrowing during the years ended December 31, 2012 and 2011:

	December 31, 2012		December 31, 2011	
	IDACORP [1]	Idaho Power	IDACORP[1]	Idaho Power
Commercial paper:				
Year end:				
Amount outstanding	$69,700	$—	$54,200	$—
Weighted average interest rate	0.50%	—%	0.47%	—%
Daily average amount outstanding during the year	$57,947	$3,578	$65,574	$—
Weighted average interest rate during the year	0.48%	0.47%	0.41%	—%
Maximum month-end balance	$69,800	$12,000	$74,400	$—

(1) Holding company only.

Impact of Credit Ratings on Liquidity and Collateral Obligations

IDACORP’s and Idaho Power’s access to capital markets, including the commercial paper market, and their respective financing costs in those markets, depends in part on their respective credit ratings. The following table outlines the ratings of Idaho Power’s and IDACORP’s securities, and the ratings outlook, by Standard & Poor’s Ratings Services and Moody’s Investors Service as of the date of this report:

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	S&P IDACORP	S&P Idaho Power	Moody’s IDACORP	Moody’s Idaho Power
Corporate Credit Rating/Long-Term Issuer Rating	BBB	BBB	Baa 2	Baa 1
Senior Secured Debt	None	A-	None	A2
Senior Unsecured Debt	None	BBB	None	Baa 1
Short-Term Tax-Exempt Debt	None	BBB/A-2	None	Baa 1/ VMIG-2
Commercial Paper	A-2	A-2	P-2	P-2
Senior Unsecured Credit Facility	None	None	Baa 2	Baa 1
Rating Outlook	Stable	Stable	Stable	Stable

These security ratings reflect the views of the ratings 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 agency has its own methodology for assigning ratings and, accordingly, each rating should be evaluated independently of any other rating.

Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2012, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on its unsecured debt to below investment grade Idaho Power could be subject to requests by its wholesale counterparties to post additional performance assurance collateral, and counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power’s current energy and fuel portfolio and market conditions as of December 31, 2012, the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $7.2 million. To minimize capital requirements, Idaho Power actively monitors its portfolio exposure and the potential exposure to additional requests for performance assurance collateral, through sensitivity analysis.

Capital Requirements

Idaho Power's construction expenditures, excluding AFUDC, were $228 million during the year ended December 31, 2012, including $28 million for construction of the Langley Gulch power plant. The table below presents Idaho Power's estimated cash requirements for construction, excluding AFUDC, for 2013 through 2015 (in millions of dollars).

	2013	2014-2015
Ongoing capital expenditures (excluding item listed below in this table)	$210-218	$500-505
Jim Bridger plant SCR (detailed below)	35-37	70-75
Total	$245-255	$570-580

Major Infrastructure Projects: Idaho Power has recently completed and is undertaking a number of significant infrastructure projects, described below.

Langley Gulch Power Plant: The Langley Gulch power plant is a natural gas-fired combined-cycle combustion turbine power generating plant with a generation nameplate capacity of 318 MW. Idaho Power placed the plant in service on June 29, 2012. Idaho Power incurred approximately $397 million ($352 million, excluding AFUDC) of capital expenditures associated with the project from inception to December 31, 2012.

AMI/Smart Grid and American Recovery and Reinvestment Act of 2009 (ARRA): The advanced metering infrastructure project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. In December 2011, Idaho Power completed the installation of its advanced metering technology at a cost of $71.8 million. Under the ARRA, Idaho Power was awarded a grant of $47 million from the DOE for the advanced metering technology and a new customer information and billing system. The grant was signed by the DOE in April 2010 and applies to project costs incurred beginning in August 2009 for a three-year term. As of December 31, 2012, Idaho Power had invoiced approximately $41.5 million to the DOE, of which $41 million had been received. The costs to be reimbursed by the grant are not included in the Capital Requirements table above.

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Jim Bridger Plant Selective Catalytic Reduction: Idaho Power and the plant co-owners intend to install selective catalytic reduction (SCR) equipment to reduce nitrogen oxide (NO_x) emissions at the Jim Bridger power plant, in order to comply with regional haze rules. SCR is required to be installed and operational on unit 3 by 2015 and unit 4 by 2016. An equivalent technology will be required for NO_x reductions on unit 2 by 2021 and unit 1 by 2022. Idaho Power estimates that the total cost for Idaho Power's share of the upgrades on units 3 and 4 is approximately $120 million, excluding AFUDC. While Idaho Power does not have estimates for the cost to install SCR on units 1 and 2, particularly given the technological changes that may occur prior to the installation date on those units, it is possible that the costs will be equal to, or greater than, the costs for units 3 and 4. Refer to Part I, Item I - “Business - Environmental Regulation and Costs” and Part II, Item 7 - “MD&A - Environmental Matters” for additional discussion on environmental controls and anticipated costs, which will be significant in the foreseeable future.

Boardman-to-Hemingway Transmission Line: The Boardman-to-Hemingway line, a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho, would provide transmission service to meet needs identified in the 2011 IRP. Idaho Power's estimated share of the cost of the permitting phase of the project is $13 million, including AFUDC. Total cost estimates for the project are between approximately $890 million and $940 million, including AFUDC. This cost estimate excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs beyond the permitting phase are not included in the table above.

In January 2012, Idaho Power, PacifiCorp, and the Bonneville Power Administration (BPA) entered into a Joint Permit Funding Agreement (B2H Funding Agreement), which provides that the parties will seek to jointly fund and support the process of completing environmental studies, including an environmental impact statement (EIS) pursuant to the National Environmental Policy Act, and obtaining governmental authorizations and permits for rights-of-way over public lands, necessary to develop the project. The planning, design, procurement, and acquisition of private rights-of-way, private easements, and similar private property interests are not within the scope of the B2H Funding Agreement. Idaho Power is designated as the project manager, responsible for administering and overseeing the project and for the day-to-day activities involved in advancing the project. The B2H Funding Agreement assigns each party a permitting interest based on each party's specified capacity ownership interests. The agreement provides for permitting interests of 21.21 percent for Idaho Power, 24.24 percent for BPA, and 54.55 for PacifiCorp in the project. The agreement further provides that during future negotiations pertaining to development and construction agreements, the parties will seek to retain interests in the project equal to their respective permitting interests. PacifiCorp or BPA may withdraw from the B2H Funding Agreement at any time.

In October 2012, the BPA issued a statement that it had completed an initial prioritization of potential service arrangements for its customer load in southeastern Idaho and, while it had not made a final decision on options for this service, the BPA identified the Boardman-to-Hemingway line with a transmission asset swap as a top priority for pursuit during 2013 and beyond. According to the BPA, of the options it evaluated, the Boardman-to-Hemingway line with a transmission asset swap has the potential to keep the BPA's costs low relative to the other options considered.

Federal and state permitting continues to move forward with a draft EIS expected to be issued in mid-2013. The completion date of the project is subject to siting, permitting, regulatory approvals, in-service date requirements of the parties electing to construct the line, the terms of any resulting joint construction agreements, and other conditions. Based on Idaho Power's assessment of those and other factors, Idaho Power continues to believe that a project in-service date prior to 2018 is unlikely.

Memorandum of Understanding, dated January 12, 2012, among Idaho Power, PacifiCorp, and BPA (2012 MOU): Executed in connection with the BPA's participation in the joint funding agreement for the Boardman-to-Hemingway line, the 2012 MOU provides that the parties will negotiate in good faith the terms of mutually satisfactory definitive agreements that would allow BPA to meet its load service obligations in southeast Idaho. It provides that the parties will explore opportunities to establish eastern Idaho load service from the Hemingway substation in exchange for similar service from the Federal Columbia River Transmission System. The 2012 MOU outlines at least two potential alternatives for further negotiation, including a network service option and an asset ownership rights option on the parties' transmission systems, both of which include BPA participation in the Boardman-to-Hemingway transmission line. Any party may terminate the 2012 MOU at any time, without penalty, and the 2012 MOU automatically expires on December 31, 2014.

Gateway West Transmission Line: Idaho Power and PacifiCorp are pursuing the joint development of the Gateway West project, a 500-kV transmission project between a station located near Douglas, Wyoming and the Hemingway station. Idaho Power's estimated cost for the permitting phase of the Gateway West project is approximately $24 million, including AFUDC. As of the date of this report, Idaho Power estimates the total cost for its share of the project (including both permitting and construction) to be between $150 million and $300 million, including AFUDC. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs are not included in the table above. Timing of the construction of each segment of the project is subject to siting, permitting, regulatory approvals, in-service date requirements of the parties electing to construct the line, the terms of any resulting joint construction agreements, and other conditions.

In January 2012, Idaho Power and PacifiCorp entered into a Project Development Agreement (Gateway Funding Agreement) outlining the terms under which the parties will jointly own, develop, design, permit, site, and acquire rights-of-way for the Gateway West transmission project. Idaho Power's interest in the Gateway West project applies to four of ten segments involved in the project, referred to as segments 6 (which Idaho Power had previously constructed and is included only for purposes of federal permitting related to the Gateway West project), 8, 9, and 10, comprised of 88, 126, 152, and 34 miles, respectively and each of which is 500-kV. PacifiCorp is designated as the project manager under the agreement. The Gateway Funding Agreement provides that the project manager may seek to reconfigure portions of the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations. Further, PacifiCorp retains the right to remove specified segments from the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations specified in the Gateway Funding Agreement.

Each party is responsible for its pro rata share, based on its respective federal and state permitting ownership interest, of the costs incurred under the agreement. Idaho Power's state permitting interest in its segments is 100 percent for segment 6 and 33 percent for each of segments 8, 9, and 10, with a federal permitting interest in the project of 11 percent. The Gateway Funding Agreement provides for the parties to subsequently meet to negotiate the terms and conditions of one or more definitive development and construction agreements for the Gateway West transmission line. The agreement specifies that the parties intend that the terms of any construction agreement would provide that Idaho Power is entitled to one-third of the anticipated bi-directional transmission capacity on segments 8, 9, and 10, and one-third of any total incremental system capacity on those segments, and that PacifiCorp is entitled to the remaining two-thirds interest. A party may withdraw from the federal permitting project, all or a portion of the state permitting project (relating to one or two of segments 8, 9, and 10), or the agreement in its entirety. Upon withdrawal, the withdrawing party forfeits its rights, title, and interest in the agreement and associated tangible and intangible property rights or, if withdrawing from less than all segments, its rights, title, and interest in those segments from which it withdraws.

In October 2012, the U.S. Bureau of Land Management (BLM) released its preferred routes for the project, and Idaho Power is engaged in discussions with stakeholders as the routes are evaluated. While the BLM's schedule provides for the issuance of a final EIS in the first quarter of 2013 and a record of decision in mid-2013, Idaho Power expects that those milestones could be delayed until later in 2013.

Shoshone Falls Plant Expansion: The Shoshone Falls plant expansion project was included in Idaho Power's 2011 IRP and consists of constructing a new powerhouse, intake structure, penstock, and substation and the installation of a new turbine to increase the nameplate generation capacity of the plant from 12.5 MW to 61.5 MW. Idaho Power estimates the total cost of the generation capacity expansion project to be $116 million, excluding AFUDC, with an in-service date during 2019, subject to the outcomes of further engineering and cost studies and regulatory authorization. The estimated 2019 in-service date is a two year delay from the prior estimated 2017 in-service date.

2013 IRP Update and Potential Changes to Capital Project Mix: As a public utility under the jurisdiction of the FERC, the IPUC, and the OPUC, Idaho Power is obligated to plan for and expand its transmission system to provide requested firm transmission service to third parties, to construct and place in service sufficient generation and transmission capacity to reliably deliver resources to network customers and the company’s retail customers, and otherwise take actions to fulfill its obligation to provide safe and reliable electric service. As part of its resource planning, and in accordance with regulatory requirements, Idaho Power prepares and publishes an IRP every two years. The IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and near-term and long-term action plans. Idaho Power's future resource build-out plans are heavily influenced by the results of the IRP process. Refer to Item 1 - "Business - Utility Operations - Resource Planning" in this report for additional information on Idaho Power's IRP.

Based on preliminary work conducted on the 2013 IRP, Idaho Power expects a significant change in its assumptions relative to the 2011 IRP. In the 2011 IRP, Idaho Power identified resource needs in the relative near-term. However, based on one scenario that would exclude demand response programs and power capacity from the proposed Boardman-to-Hemingway 500-kV transmission line, the preliminary peak-hour load and resource balance prepared for the 2013 IRP indicates no peak-hour load deficit until 2016. Under those assumptions, the need for near-term peak-hour resources does not exist. Idaho Power anticipates that the expected near-term resource sufficiency will impact the timing of development of supply-side resources, including those described above, and the need for demand response programs in the near-term.

At times, Idaho Power may seek to accelerate, scale back, modify, or eliminate projects, or seek alternative projects, to accommodate anticipated resource needs and to help ensure its ability to provide reliable electric service and meet load and transmission capacity obligations. Scaling back or eliminating a project due to regulatory challenges or other factors influencing the feasibility of a project may result in Idaho Power pursuing one or more separate, more costly projects. For instance, if Idaho Power were unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads, it may terminate those projects and, as an alternative, develop additional generation facilities within areas where Idaho Power has available transmission capacity. Idaho Power's IRP seeks to address these potential alternatives and their associated risks and costs. Termination of a project carries with it the potential for a write-off of all or a significant portion of the costs associated with the project.

Environmental Regulation Costs: Idaho Power anticipates that it will incur significant expenditures for the installation of environmental controls at its coal plants and for its hydroelectric relicensing efforts. These cost estimates are summarized in Item 1 - "Business" of this report. The capital portion of these amounts is included in the Capital Requirements table above but do not include costs related to possible changes in current or new environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and emissions from coal-fired and gas-fired generation plants.

Other Capital Requirements: IDACORP's non-regulated capital expenditures are primarily related to IFS's tax-structured investments. As of the date of this report, IDACORP does not anticipate any significant non-regulated expenditures for the period from 2013 through 2015.

Defined Benefit Pension Plan Contributions

Idaho Power contributed $44.3 million, $18.5 million, and $60 million to its defined benefit pension plan in 2012, 2011, and 2010, respectively. Idaho Power has evaluated the potential impact of recently approved federal legislation that will alter the timing and amount of future contributions to the defined benefit pension plan. The legislation, signed into law in July 2012, provides a smoothing mechanism applicable to the calculation of plan minimum contributions, and will reduce minimum amounts required to be contributed to the plan in at least the next few years. The legislation's partial funding relief is automatically effective for all contributions beginning in 2013, and Idaho Power chose to adopt the funding relief for its 2012 contributions. Idaho Power does not have a minimum contribution requirement for 2013. In 2014 and beyond, Idaho Power expects significant contribution obligations under the pension plan. Refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and the section titled "Contractual Obligations" below in this MD&A for information relating to those obligations. In May 2011, the IPUC authorized Idaho Power to increase its annual recovery and amortization of deferred pension costs from $5.4 million to $17.1 million. The primary impact of pension contributions is on cash flows, as cost recovery lags the timing of contributions.

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Contractual Obligations

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

	Payment Due by Period				
	Total	2013	2014-2015	2016-2017	Thereafter
Idaho Power:	(millions of dollars)				
Long-term debt[(1)]	$1,540	$71	$2	$2	$1,465
Future interest payments[(2)]	1,304	79	152	152	921
Operating leases	24	2	4	2	16
Purchase obligations:					
Cogeneration and small power production	3,858	171	369	379	2,939
Fuel supply agreements	308	74	120	19	95
Purchased power & transmission[(3)]	27	6	9	7	5
Other[(4)]	169	49	37	24	59
Pension and postretirement benefit plans[(5)]	277	7	91	136	43
Other long-term liabilities - Idaho Power	1	—	—	1	—
Total Idaho Power	7,508	459	784	722	5,543
Other	1	1	—	—	—
Total IDACORP	$7,509	$460	$784	$722	$5,543

(1) For additional information, see Note 4 – "Long-Term Debt" to the consolidated financial statements included in this report.
(2) 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, 2012.
(3) Approximately $9 million of the obligations included in 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 has been included in the table for presentation purposes.
(4) Approximately $114 million of the amounts in other purchase obligations are 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, has been included in the table for presentation purposes.
(5) Idaho Power estimates pension contributions based on actuarial data. As of the date of this report, Idaho Power cannot estimate pension contributions beyond 2017 with any level of precision, and amounts through 2017 are estimates only. For more information on pension and postretirement plans, refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report.

Dividends

The amount and timing of dividends paid on IDACORP's common stock are within the discretion of IDACORP's board of directors. IDACORP's board of directors reviews the dividend rate periodically to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power 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 Idaho Power.

IDACORP has a dividend policy that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the IDACORP board of directors' dividend decisions. Notwithstanding the dividend policy adopted by the IDACORP board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will continue to take into account the foregoing factors, among others.

On January 19, 2012, IDACORP's board of directors voted to increase the quarterly dividend, commencing with the dividend paid on February 29, 2012, to $0.33 per share of IDACORP common stock, from the prior quarterly dividend amount of $0.30 per share of IDACORP common stock. On September 20, 2012, IDACORP's board of directors voted to increase the quarterly dividend again in 2012, commencing with the dividend payable on November 30, 2012, to $0.38 per share of IDACORP

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common stock. As of the date of this report, IDACORP’s management anticipates recommending to the board of directors an additional increase to the quarterly dividend in September 2013 of at least ten percent.

For additional information relating to IDACORP and Idaho Power dividends, including additional restrictions on IDACORP’s and Idaho Power’s payment of dividends, see Note 6 – “Common Stock” to the consolidated financial statements included in this report.

Contingencies and Proceedings

IDACORP and Idaho Power are involved in a number of litigation, alternative dispute resolution, and administrative proceedings, and are subject to claims and legal actions arising in the ordinary course of business, that could affect their future results of operations and financial condition. Certain legal or administrative proceedings to which IDACORP or Idaho Power are parties or are otherwise involved, and certain actual or potential legal claims pertaining to Idaho Power, are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. Except where noted in Note 10, in many instances IDACORP and Idaho Power are unable to predict the outcomes of the matters or estimate the impact the proceedings may have on their financial positions, results of operations, or cash flows.

Idaho Power is also actively monitoring various environmental regulations that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to determine the financial impact of potential new regulations, but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

Off-Balance Sheet Arrangements

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $66 million at December 31, 2012, representing IERCo's one-third share of BCC's total reclamation obligation of $199 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2012, the value of the reclamation trust fund totaled $72 million. During 2012 the reclamation trust fund distributed approximately $20 million for reclamation activity costs associated with the BCC surface mine. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

Impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) establishes regulatory jurisdiction by the Commodity Futures Trading Commission (CFTC) and the SEC for certain swaps (which include a variety of derivative instruments) and the users of such swaps. While Idaho Power believes that a number of obligations arising from rules issued under the Dodd-Frank Act will not directly apply to Idaho Power, the company believes that other participants in the commodities markets (such as swap dealers and major swap participants) will pass along their increased costs. While implementation of the rules is in its infancy, and temporary operational disruptions and liquidity in the commodities markets could be adversely impacted, as of the date of this report Idaho Power expects that the long-term financial and operational impact of the swap-related provisions of the Dodd-Frank Act and the CFTC's and SEC's associated rules will not be significant.

REGULATORY MATTERS

Introduction

As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the IPUC and the OPUC, which determine the rates that Idaho Power charges to its general business customers. Idaho Power 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. Also, as a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its OATT. Idaho Power uses general rate cases, cost adjustment mechanisms, and subject-specific filings to recover its costs of providing service and the costs of its energy efficiency and demand-side resources programs, seeking to earn a return on

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investment where permitted by regulators. Idaho Power remains focused on communicating with regulators the necessity of investments to better serve its customers, the prudence of the costs incurred, and the importance of a reasonable return on investment for IDACORP's shareholders.

Idaho Power's need for rate relief and the development of rate case plans takes into consideration short-term and long-term needs, as well as specific factors that can affect the timing of rate filings. Such factors include, among other things, in-service dates of major capital investments and the timing of changes in major revenue and expense items. Idaho Power filed general rate cases in Idaho and Oregon during 2011, as well as a single-issue rate case for the Langley Gulch power plant in Idaho and Oregon in 2012, which have largely concluded. Idaho Power will continue to assess its need for general rate relief in consideration of the factors described above. Between general rate cases, Idaho Power relies upon power cost adjustment mechanisms, riders, and other mechanisms to reduce regulatory lag, which refers to the period of time between making an investment or incurring an expense and earning a return and recovering that investment or expense. Management's focus on constructive regulatory outcomes in 2011 and 2012 has been targeted largely at general revenue rate cases and rate mechanisms. For 2013, management will have a renewed focus on optimizing operations, evaluating and managing employee attrition, and managing growth in expenses.

Regulatory mechanisms and other regulatory matters, including in many cases their design and their financial impact on IDACORP and Idaho Power, are also discussed in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, which should be read in conjunction with the discussion below.

Idaho and Oregon Significant Regulatory Developments

Included below are notable regulatory developments affecting Idaho Power and largely completed during 2010, 2011, and 2012. Refer to Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report for a description of the applicable regulatory mechanism and associated orders of the IPUC and OPUC.

Description	Effective Date	Estimated Annualized $ Impact (millions)[1]
2010 Idaho settlement	6/1/2010	$ 89
2010 Idaho PCA [2]	6/1/2010	(147)
2010 Idaho pension expense recovery	6/1/2010	5
2010 Oregon annual power cost update [2]	6/1/2010	3
2011 Idaho PCA [2]	6/1/2011	(40)
2011 Idaho pension expense recovery	6/1/2011	12
2011 Oregon annual power cost update [2]	6/1/2011	(2)
2011 Idaho general rate case settlement	1/1/2012	34
2012 Oregon general rate case settlement	3/1/2012	2
2012 Idaho PCA[2]	6/1/2012	43
Idaho - Boardman power plant cost recovery	6/1/2012	1
Revenue sharing pursuant to January 2010 Idaho settlement agreement [2]	6/1/2012	(27)
Idaho depreciation rate for non-AMI meters	6/1/2012	(11)
Idaho depreciation update (other than non-AMI meters and Boardman plant)	6/1/2012	(1)
2012 Oregon annual power cost update [2]	6/1/2012	2
Idaho - Langley Gulch power plant	7/1/2012	58
Oregon - Langley Gulch power plant	10/1/2012	3

[1] The annual amount collected in rates is typically not recovered on a linear basis (i.e., 1/12th per month), and is instead recovered based on seasonality of sales and through Idaho Power's tiered rate structure, described above in this

MD&A. Under a tiered rate structure, Idaho Power generally records revenues disproportionately during higher-load periods.
(2) The rate changes for the Idaho PCA and $27.1 million rate decrease resulting from revenue sharing pursuant to the January 2010 settlement agreement are applicable only for one-year periods. Similarly, a portion of the rate changes from the Oregon annual power cost update are applicable only for one-year periods.

Resetting of Idaho Base Rates -- 2011 Idaho General Rate Case Settlement: In December 2011, the IPUC approved a settlement stipulation in Idaho Power's Idaho general rate case, which provided for a 7.86 percent authorized rate of return on

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an Idaho-jurisdiction rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdictional base rate revenues. New rates in conformity with the settlement became effective on January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity.

Resetting of Oregon Base Rates - 2012 Oregon General Rate Case Settlement: On February 23, 2012, the OPUC approved a settlement stipulation in Idaho Power's Oregon general rate case providing for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation went into effect on March 1, 2012. The OPUC is conducting a second phase of the proceedings to address the prudence of Idaho Power's pollution control investments at the Jim Bridger coal-fired power plant.

Idaho ROE Support Through 2014 via December 2011 Settlement: In December 2011, the IPUC issued an order, separate from the then-pending Idaho general rate case proceeding, approving a settlement stipulation that provided as follows:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more than $25 million in 2012;
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho-jurisdictional earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA adjustment; and
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho-jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 25 percent to Idaho Power and 75 percent to benefit Idaho customer rates through an offset in the pension balancing account, which would reduce the amount Idaho Power would collect from customers in future rates.

The December 2011 settlement stipulation provided that the Idaho ROE thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be automatically adjusted prospectively in the event the IPUC approves a change to Idaho Power's authorized return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2015. As Idaho Power's 2012 Idaho ROE exceeded 10.5 percent, Idaho Power did not amortize additional ADITC in 2012. In accordance with the sharing provisions of the settlement stipulation, Idaho Power recorded a $7.2 million provision against current revenues, to be refunded to customers through a future rate reduction, and an additional $14.6 million of pension expense, which will benefit Idaho customers by reducing the amount of deferred pension expense that will be collected from customers in the future.

The December 2011 settlement and sharing mechanism followed a similar Idaho settlement and sharing mechanism approved in January 2010, described further in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, which had a substantial impact on IDACORP's and Idaho Power's 2011 results of operations (as discussed in Note 3).

Increase in Rate Base -- Completion and Inclusion of the Langley Gulch Power Plant: The Langley Gulch power plant became commercially available on June 29, 2012. On that date the IPUC issued an order approving a $58.1 million, or 6.83 percent, increase in annual Idaho-jurisdiction base rates, effective July 1, 2012, for recovery of Idaho Power's investment in the power plant and associated costs. On September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon-jurisdiction base rates for recovery of the investment and associated costs, with new rates in effect October 1, 2012.

Change in Deferred (Accrued) Net Power Supply Costs

Deferred power supply costs represent certain differences between Idaho Power's actual net power supply costs and the costs included in its retail rates, the latter being based on annual forecasts of power supply costs. Deferred power supply costs are recorded on the balance sheets for future recovery or refund through customer rates. The table that follows summarizes the change in deferred net power supply costs over the last two years.

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	Idaho	Oregon[1]	Total
Balance at December 31, 2010	$17,559	$12,194	$29,753
Current period net power supply costs accrued	(27,768)	(1,523)	(29,291)
Prior costs expensed and recovered through rates	(6,849)	(2,357)	(9,206)
Transfer of energy efficiency expenditures	10,000	—	10,000
SO_2 allowance and renewable energy certificate (REC) sales	(5,884)	(447)	(6,331)
Interest and other	(179)	623	444
Balance at December 31, 2011	(13,121)	8,490	(4,631)
Current period net power supply costs deferred	45,063	1,523	46,586
2011 revenue sharing liability applied to PCA true-up mechanism[2]	(27,201)	—	(27,201)
Prior deferred costs amortized and refunded (recovered) through rates	33,332	(2,178)	31,154
SO_2 allowance and renewable energy certificate (REC) sales	(3,217)	(160)	(3,377)
Interest and other	(285)	656	371
Balance at December 31, 2012	$34,571	$8,331	$42,902

(1) Oregon power supply cost deferrals are subject to a statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year (approximately $3 million). Deferrals are amortized sequentially.
(2) 2011 revenue sharing includes a $27.1 million liability together with carrying charges.

FERC Compliance Programs

The FERC has approved an extensive number of reliability standards developed by the NERC and the Western Electricity Coordinating Council (WECC), including critical infrastructure protection (CIP) standards and regional standard variations. As part of its compliance program, Idaho Power periodically reviews its operations for compliance with FERC rules, orders, and standards and self-reports compliance issues to the FERC and the WECC. Recent reports Idaho Power has submitted to the FERC have generally focused on Standards of Conduct and Idaho Power’s FERC OATT. Consistent with prior years, during 2012 Idaho Power self-reported to the FERC and received notices of alleged violations from the FERC and the WECC. Idaho Power has also received notification that the FERC intends to take no further action regarding several issues previously reported by Idaho Power. Consistent with its historical practice, Idaho Power is working with the FERC and the WECC to resolve alleged violations and items it self-reported to the FERC and the WECC. Idaho Power is unable to predict what action, if any, the WECC or the FERC will take on those unresolved matters, but based on the nature of the potential violations Idaho Power does not expect any material adverse effect from currently alleged violations on its financial position, results of operations, or cash flows. Idaho Power plans to continue its efforts to reduce potential violations through its compliance program and its approach of self-reporting compliance issues to, and working with, the FERC and the WECC.

Relicensing of Hydroelectric Projects

Idaho Power, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses have a term of 30 to 50 years depending on the size, complexity, and cost of the project. Costs for the relicensing of Idaho Power's hydroelectric projects are recorded in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges are transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $161 million for the HCC, Idaho Power's largest hydroelectric complex and a major relicensing effort, were included in construction work in progress at December 31, 2012. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho jurisdiction rates approximately $6.5 million annually ($10.6 million grossed up for income taxes) of AFUDC relating to the HCC relicensing project. Collecting these amounts now will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. Through December 31, 2012, Idaho Power has collected approximately $24.7 million ($41.6 million grossed up for income taxes) of AFUDC related to the HCC relicensing project through customer rates. In addition to the discussion below, see "Environmental Matters" in this MD&A for a discussion of environmental compliance under FERC licenses for Idaho Power's hydroelectric generating plants.

Hells Canyon Complex: The HCC, located on the Snake River where it forms the border between Idaho and Oregon, provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 32 percent of its total generating nameplate capacity. In July 2003, Idaho Power filed an application with the FERC for a new license in anticipation of the July 2005 expiration of the then-existing license. Since the expiration of that license, Idaho Power has been operating the project under annual licenses issued by the FERC. In December 2004, Idaho Power and eleven other parties, including NMFS and

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USFWS, involved in the HCC relicensing process entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on ESA listed species pending the relicensing of the project. In August 2007 the FERC Staff issued a final EIS for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, federal and state agencies, Native American tribes, and the public about the environmental effects of Idaho Power's operation of the HCC. Certain portions of the final EIS involve issues that may be influenced by water quality certifications for the project under Section 401 of the Clean Water Act (CWA) and formal consultations under the Endangered Species Act (ESA), which remain unresolved.

In connection with its relicensing efforts, Idaho Power has filed water quality certification applications, required under Section 401 of the CWA, with the states of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. Section 401 of the CWA requires that a state either approve or deny a Section 401 water quality certification application within one year of the filing of the application or the state may be considered to have waived its certification authority under the CWA. As a consequence, Idaho Power has been filing and withdrawing its Section 401 certification applications with Oregon and Idaho on an annual basis while it has been working with the states to identify measures that will provide reasonable assurance that discharges from the HCC will adequately address applicable water quality standards.

In September 2007, in connection with the issuance of its final EIS, the FERC notified the NMFS and the USFWS of its determination that the licensing of the HCC was likely to adversely affect ESA-listed species, including the bull trout and fall Chinook salmon and steelhead, under the NMFS's and USFWS's jurisdiction and requested that the NMFS and USFWS initiate formal consultation under Section 7 of the ESA on the licensing of the HCC. Each of the NMFS and USFWS responded to the FERC that the conditions relating to the licensing of the HCC were not fully described or developed in the final EIS as the measures to address the water quality effects of the project were yet to be fully defined by the Section 401 certification process pending before the Oregon and Idaho Departments of Environmental Quality. The NMFS and USFWS therefore recommended that formal consultation under the ESA be delayed until the Section 401 certification process is completed. Idaho Power continues to work with Idaho and Oregon in the development of measures to provide reasonable assurance that any discharges from the HCC will comply with applicable state water quality standards so that appropriate water quality certifications can be issued for the project, and continues to cooperate with the USFWS, NMFS, and the FERC in an effort to address ESA concerns. Measures that have been contemplated include potential watershed improvements or the installation of a temperature control structure to address water temperatures during a small portion of the year. Both the watershed approach and temperature control structure would add substantially to project costs. For instance, in its August 2007 final EIS the FERC's proposed protection, mitigation, and enhancement measures had an estimated cost of approximately $15 million per year, excluding costs associated with the Section 401 certification because they had not been defined at that time, and remain undefined. As of the date of this report, Idaho Power is unable to predict the timing of issuance by the FERC of any license order or the ultimate capital investment and ongoing operating and maintenance costs Idaho Power will incur in complying with the license.

Swan Falls Project: In September 2012, the FERC issued to Idaho Power a 30-year license for continued operation of the Swan Falls hydroelectric project (SFP). Idaho Power believes that operational changes associated with the new license for the SFP will be modest and that the capital investments it will be required to make under the terms of the license will be within the range Idaho Power expected at the time of submission of its application for the license.

Shoshone Falls Plant Expansion: On July 1, 2010, the FERC amended the license for the Shoshone Falls project to expand its nameplate generating capacity from approximately 12.5 MW to approximately 61.5 MW. The amended license has an expiration date of 2034, but provides that the license will be extended to 2044 following completion of the proposed generation capacity expansion project. On May 1, 2012, FERC granted Idaho Power a two-year schedule extension, through July 2017, to complete construction of the expansion. However, Idaho Power does not expect that it would complete the generation capacity expansion project prior to 2019, and thus plans to request an additional two-year extension from the FERC. Idaho Power's determination to proceed with the expansion project remains subject to the outcome of additional cost studies and analysis and the results of further engineering and design work, and further analysis of Idaho Power's supply-side resource needs. If Idaho Power ultimately determines to move forward with the full project, Idaho Power plans to obtain regulatory support from the IPUC and OPUC prior to commencement of construction to mitigate in part the regulatory cost-recovery risk associated with the project.

Renewable Energy Contracts, Renewable Energy Certificates, and Emission Allowances

Renewable Portfolio Standards: Numerous proponents have introduced legislation in the U.S. Congress that would require electric utilities to obtain a specified percentage of their electricity from renewable sources, commonly referred to as a "renewable portfolio standard" or "RPS." However, as of the date of this report no federal or State of Idaho RPS is in effect.

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Idaho Power will be required to comply with a 10-percent RPS in Oregon beginning in 2025, and Idaho Power expects to meet this requirement with RECs from the Elkhorn Valley wind project. Idaho Power continues to monitor proposed federal RPS legislation and the possibility of additional state RPS legislation.

Pursuant to an IPUC order, Idaho Power is selling its near-term RECs and returning to customers their share (shared 95% with customers in the Idaho jurisdiction) of those proceeds through the PCA. For the years ended December 31, 2012 and 2011, Idaho Power's REC sales totaled $3.5 million and $6.5 million, respectively. Idaho Power has sold all of its 2011 and earlier vintage RECs. Idaho Power has sold a portion of its 2012 RECs and intends to continue selling its 2012 and later RECs as they are generated and become available for sale.

Were Idaho Power to be subject to additional RPS legislation, it may cease in full or in part the sale of RECs it receives, seek to obtain RECs from additional projects, generate RECs from any REC-generating facilities it may own, or purchase RECs in the market. Ordinarily, Idaho Power does not receive the RECs associated with PURPA projects. However, an order issued by the IPUC on December 18, 2012, described below, provides that Idaho Power will own a portion of the RECs generated by some future PURPA projects. The required purchase of RECs to meet RPS requirements would increase Idaho Power's costs, which Idaho Power expects would be wholly or largely passed on to customers through rates and the power cost adjustment mechanism.

Renewable Energy Contracts: Idaho Power purchases wind power from both cogeneration and small power production (CSPP) and non-CSPP facilities, including its largest non-CSPP wind power project -- the Elkhorn Valley wind project with a 101 MW nameplate capacity. As of December 31, 2012, Idaho Power had contracts to purchase energy from on-line CSPP wind power projects with a combined nameplate rating of 577 MW. In addition to its power purchase arrangements with wind power generators, Idaho Power has contracts for the purchase of power from other renewable generation sources, such as biomass, solar, and small hydroelectric projects. As of December 31, 2012, Idaho Power had the number and nameplate capacity of signed CSPP-related agreements with terms ranging from one to 35 years set forth in the table below.

Status	Number of CSPP Contracts	Nameplate Capacity (MW)
On-line as of December 31, 2012	103	779
Contracted and projected to come on-line by year-end 2014	6	52

Pursuant to the requirements of Section 210 of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power's purchase of power from CSPP facilities. A key component of the PURPA power purchase contracts is the energy price contained within the agreements. Regulatory-mandated execution of PURPA agreements may result in Idaho Power acquiring energy it does not need at above wholesale market prices and require additional operational integration measures, thus increasing costs to Idaho Power's customers. Substantially all PURPA power purchase costs are recovered through base rates and Idaho Power's power supply cost mechanisms, and thus the primary impact of PURPA agreements is on customer rates.

PURPA Proceedings at the IPUC and OPUC: In response to a November 5, 2010 application filed by Idaho Power and two other electric utilities with Idaho service territories, on February 7, 2011 the IPUC issued an order temporarily reducing the eligibility cap for PURPA projects entitled to published avoided cost rates from 10 aMW to 100 kW for wind and solar PURPA projects while the IPUC further investigated the implications of large projects disaggregating into smaller projects to qualify for higher published avoided cost rates and other benefits. On June 8, 2011, the IPUC issued an order maintaining the 100 kW eligibility cap for published avoided cost rates for wind and solar PURPA projects, and initiating additional proceedings to allow the parties to investigate and analyze the methodologies used in determining the appropriate power purchase price for PURPA projects. On that same date, the IPUC issued orders disapproving 13 PURPA wind power purchase agreements. Idaho Power estimates that the payments over the lives of the disapproved agreements would have totaled approximately $1.3 billion.

Idaho Power recently concluded proceedings at the IPUC relating to the determination of appropriate power purchase prices and other terms of PURPA power purchase agreements. On December 18, 2012, the IPUC issued an order addressing that and other aspects of PURPA contracts. The IPUC retained the existing 100 kW threshold for wind and solar projects eligible for published avoided cost rates and determined that for projects not eligible for published avoided cost rates, the price used for power purchase determinations would be updated annually based on updated natural gas prices and Idaho Power's updated load forecast. The IPUC also determined that RECs will be owned by the PURPA project developer for projects eligible for published avoided cost rates, and apportioned equally between the project developer and Idaho Power for other projects. The IPUC's order also provided that new projects will be paid for capacity based on the project's ability to deliver during peak hours and when Idaho Power's long-range plan shows the company is capacity deficient. Similar proceedings at the OPUC are also ongoing.

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ENVIRONMENTAL MATTERS

Overview

Idaho Power is subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the environment. Current and pending environmental legislation relates to, among other items, climate change, greenhouse gas emissions and air quality, mercury and other emissions, hazardous wastes, polychlorinated biphenyls, and endangered and threatened species, and include, among others, the Clean Air Act (CAA), the CWA, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Comprehensive Environmental Response, Compensation and Liability Act, and the ESA. In addition to imposing continuing compliance obligations and associated costs, these laws and regulations provide authority to levy substantial penalties for noncompliance, injunctive relief, and other sanctions. These laws and regulations are administered by federal agencies including the U.S. Environmental Protection Agency (EPA), the USFWS, and the National Oceanic and Atmospheric Administration (NOAA) (formerly the National Marine Fisheries Service), and state and local agencies. Idaho Power's three coal-fired power plants and three natural gas-fired combustion turbine power plants are also subject to many of these regulations. Idaho Power's 17 hydroelectric projects are also subject to a number of water discharge standards and other environmental requirements. Because these plants utilize different fuel sources, there is the likelihood that each plant will be subject to different regulations and requirements. See Part I, Item 2 - "Properties" in this report for further information on these power plants.

Compliance with current and future environmental laws and regulations may:
- increase the operating costs of generating plants;
- increase the construction costs and lead time for new facilities;
- require the modification of existing generating plants;
- require the curtailment or shut down of existing generating plants; or
- reduce the output from current generating facilities.

Current and future environmental laws and regulations will increase the cost of operating coal-fired power plants and constructing new facilities, will necessitate installation of additional pollution control devices at existing generating plants, or result in Idaho Power discontinuing operation of one or more coal-fired plants where operation becomes uneconomical. These regulations could, in turn, affect IDACORP's and Idaho Power's results of operations and financial condition if the costs associated with these environmental requirements and plant shut-downs cannot be fully recovered in rates on a timely basis. Part I - "Business - Environmental Regulation and Costs" in this report includes a summary of Idaho Power's expected capital and operating expenditures for environmental matters during the period from 2013 to 2015. Given the uncertainty of future environmental regulations, Idaho Power is unable to predict its environmental-related expenditures beyond that time, though they could be substantial. IDACORP's and Idaho Power's boards of directors review environmental issues on a regular basis, including in connection with the strategic planning process.

In connection with its IRP process, Idaho Power has been conducting cost studies and scenario analysis to assess the potential future investments necessary for the continued operation of the Jim Bridger and Valmy coal generation facilities, in light of the body of environmental laws and regulations impacting the cost of operating those plants. The Boardman coal facility was not included in the study because of the existing schedule to cease coal-fired operations at that plant by the end of 2020. Some of the future environmental control requirements for the Jim Bridger and Valmy plants are known; however, many potential additional requirements could arise from future regulations. In the analysis, the cost of future compliance was compared to the cost of replacement generation capacity provided by combined-cycle combustion turbine technology. Because of the speculative nature of many of the future requirements, the analysis was performed under a range of fuel pricing assumptions, carbon cost assumptions, plant upgrade and retirement costs, environmental regulation assumptions, and replacement costs. Idaho Power published the results of the study with its 2011 IRP update filed with the IPUC and OPUC in February 2013. Idaho Power concluded in its study that both plants should be retained in its resource portfolio. In addition to the estimated cost savings of retaining the plants under most scenarios, even with the installation of planned controls, retaining the plants also satisfies Idaho Power's desire to maintain a diversified portfolio of generation assets and fuel diversity that can mitigate risk associated with increases in natural gas prices. However, in the event significant additional operating and maintenance or capital expenditures are necessary at the Valmy plant as a result of new environmental requirements, Idaho Power will conduct a further review to determine whether such investments are economically appropriate, and whether conversion of the facility to a natural-gas fired plant would be appropriate.

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Endangered Species and Fisheries Matters

Overview: The listing of a species of fish, wildlife, or plants as threatened or endangered under the ESA may have an adverse impact on Idaho Power's ability to construct generation, transmission, or distribution facilities or relicense or operate its hydroelectric projects. When a species is added to the federal list of threatened and endangered species, it is protected from “take” and from being transported, traded, or sold. The term “take” under the ESA is interpreted to include “harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such conduct.” Section 7 of the ESA also provides that each federal agency shall ensure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of its critical habitat. The construction of generation, transmission, or distribution facilities and the licensing of Idaho Power's hydroelectric projects can be federally authorized actions that fall under Section 7 of the ESA. There are a number of threatened or endangered species within Idaho Power's service territory, which have the potential to impact the ability to construct, or the timing of construction, of infrastructure such as transmission lines. Further, there are a number of ESA listed fish and other aquatic species located in waterways in which Idaho Power has hydroelectric facilities, including fall Chinook salmon, bull trout, Bliss Rapids snail, and Snake River physa snail. To date, efforts to protect these and other listed species have not significantly affected generation levels at any of Idaho Power's hydroelectric facilities. However, the ongoing relicensing of the HCC presents endangered species and fisheries issues that may require generation or other operational adjustments. These adjustments may reduce the generation output or operating costs (and hence the economics) of the plants, potentially causing Idaho Power to rely on more expensive sources for power generation or market purchases.

ESA Developments Related to Specific Species:

Slickspot Peppergrass: This southwestern Idaho plant species was listed as threatened by the USFWS in 2009. In May 2011, the USFWS issued a proposed rule to designate critical habitat for the slickspot peppergrass and proposed to designate approximately 58,000 acres of critical habitat in four southeast Idaho counties. Approximately 98 percent of the plant species is located on federal land owned by the BLM and the U.S. Department of Defense. To date the USFWS has yet to issue a final designation of critical habitat. In August 2012, a federal district court in Idaho issued a decision vacating and remanding the USFWS's decision to list slickspot peppergrass. The BLM is now treating the species as a proposed species under ESA and will confer with the USFWS until a final decision is made. Parts of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines will cross BLM land upon which this species is located. The listing of the slickspot peppergrass will require that Idaho Power engage in an ESA Section 7 consultation with the USFWS, which will increase the cost of the transmission projects and potentially delay the receipt of a permit for construction.

Greater Sage Grouse: The greater sage grouse is considered a “candidate species” under the ESA, which allows land management agencies to implement additional conservation measures. In March 2010, the USFWS announced that listing of the greater sage grouse as threatened or endangered under the ESA is warranted but precluded by higher priority listing actions. On February 2, 2012, a federal district court in Idaho issued an order denying a request to expedite the listing of the greater sage grouse under the ESA. As a result, the USFWS has until 2015 to make a final listing determination under the ESA. On February 6, 2012, the same court issued an order holding that the BLM had violated the National Environmental Policy Act and other federal laws in connection with the granting of livestock grazing permit renewals in sage grouse habitat. Due to the presence of sage grouse in the vicinity of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines, siting of these projects has required more extensive, costly, and time consuming evaluation, permitting, and engineering. In the event the USFWS lists the greater sage grouse as threatened or endangered, federal agencies that may authorize rights-of-way to Idaho Power would be required to conduct a Section 7 consultation under the ESA for these transmission projects. Any required additional conservation measures may increase the costs of existing operations and impact the timing for siting, permitting, and constructing the Boardman-to-Hemingway and Gateway West transmission lines and other construction and transmission projects.

ESA Developments Related to Specific Projects:

Hells Canyon Relicensing Project: In 2007, the FERC requested initiation of formal consultation under the ESA with the NMFS (now the NOAA) and the USFWS regarding potential effects of HCC relicensing on several listed aquatic and terrestrial species. Formal consultation has yet to be initiated and the NOAA and USFWS continue to gather and consider information relative to the effects of relicensing on relevant ESA listed species. Idaho Power continues to cooperate with the USFWS, the NOAA, and the FERC in an effort to address ESA concerns. In December 2004, Idaho Power and eleven other parties, including NOAA and USFWS, involved in the HCC relicensing process entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on ESA listed species pending the relicensing of the project. At the conclusion of formal consultation and with the issuance of biological opinions by NOAA and USFWS and a license by the FERC, Idaho

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Power may be required to further modify or adjust operations to comply with Section 7 of the ESA. The issuance of a final biological opinion during 2013 is unlikely.

Bliss and Lower Salmon Falls Projects: As part of a settlement agreement for the current FERC hydroelectric license, Idaho Power has finalized a snail protection plan for the Bliss and Lower Salmon Falls projects in cooperation with the USFWS. Idaho Power has filed applications with the FERC to amend the licenses for the projects that will maintain operating flexibility at both projects for the remainder of their licenses. The FERC requested formal consultation with the USFWS regarding the license amendments in July 2012. The ESA Section 7 consultation included two listed snails -- the Bliss Rapids snail and the Snake River physa snail. The USFWS filed its biological opinion with the FERC in November 2012.

Swan Falls Project: In August 2010, the FERC issued a final EIS in connection with the relicensing of the SFP. The Snake River physa snail was found in the area during the EIS review. While the biological opinion includes a provision for the incidental take of the snail, Idaho Power is required to study the status of the Snake River physa snail and its habitat within and downstream of the project area for the term of the new license.

Boardman-to-Hemingway and Gateway West Transmission Projects: As noted above, the existence of slickspot peppergrass and the greater sage grouse in the proposed routes for these projects is impacting, and Idaho Power expects it to continue to impact, the cost and timing of permitting and construction of the projects.

Climate Change and the Regulation of Greenhouse Gas (GHG) Emissions

Overview: Long-term climate change could significantly affect Idaho Power's business in a variety of ways, including:

- changes in temperature and precipitation could affect customer demand and energy loads;
- extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of energy commodities;
- changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation;
- legislative and/or regulatory developments related to climate change could affect plants and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general; and
- consumer preference for, and resource planning decisions requiring, renewable or low GHG-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure.

Some recent initiatives regarding GHG emissions contemplate market-based compliance programs, such as cap-and-trade programs or emission offsets. However, the regulation of GHG emissions under the CAA could result in GHG emission limits on stationary sources that do not provide market-based compliance options. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because many new technologies for reducing CO_2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Emission standards could require significant increases in capital expenditures and operating costs, which may accelerate the retirement of coal-fired units. Due in part to the uncertainty of future GHG regulations, in its 2011 IRP Idaho Power did not include any new conventional coal resources in its resource portfolios.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions, including the specific GHG emissions limits, the timing of implementation of these limits, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through rates. Accordingly, Idaho Power cannot predict the effect on its results of operations, financial position, or cash flows of any GHG emission or other global climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be substantial. A more detailed discussion of legislative and regulatory developments related to climate change follows.

National and International GHG Initiatives: There is concern both nationally and internationally about climate change and the possible contribution of GHG emissions to climate change. In support of international efforts to reduce GHG emissions, in January 2010 the Obama Administration pledged to cut GHG emissions in the United States from 2005 levels by 17 percent by 2020 and 80 percent by 2050. Other communications from the Obama Administration have proposed the adoption of a clean

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energy standard in the U.S., calling for 80 percent of American energy to come from clean sources by 2035. Further, climate change regulation has been a recent priority of the U.S. Congress. In prior legislative sessions, legislation in both the U.S. House and Senate was introduced to enact a comprehensive climate change program, but these attempts were unsuccessful. At the same time, legislation has also been introduced seeking to amend the CAA to prohibit the EPA from promulgating regulations on the emissions of GHGs to address climate change and excluding GHGs from the definition of an "air pollutant" for purposes of addressing climate change. Neither areas of focus have culminated in legislation and have led to greater uncertainty as to the direction of GHG regulation.

At the same time, the EPA has become increasingly active in the regulation of GHGs. The EPA's endangerment finding in 2009 that GHGs threaten public health and welfare resulted in enactment of a series of EPA regulations to address GHG emissions. The EPA has issued final rules regulating GHG emissions under the New Source Review (NSR)/Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs under the CAA. Specifically, in May 2010 the EPA issued the “Tailoring Rule,” which set thresholds for GHG emissions that define when permits are required for new and existing industrial facilities. The final rule “tailors” the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. Additionally, in December 2010 the EPA issued a series of final regulations for GHG emissions designed to ensure that industrial facilities can obtain CAA permits for GHG emissions, and that facilities emitting GHGs at levels below those established in the Tailoring Rule do not need federal CAA permits. The first phase of the rules took effect in January 2011 and required imposition of Best Available Control Technology (BACT) for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year (CO_2 equivalent). In addition, Title V permit renewals or modifications for existing major sources must include applicable requirements relating to GHGs. Lawsuits opposing EPA's endangerment finding and Tailoring Rule were unsuccessful. While the rules are complex, Idaho Power believes that its owned and co-owned generation plants are, as of the date of this report, in compliance with the new GHG Tailoring Rules.

In addition, in April 2012, the EPA proposed New Source Performance Standards (NSPS) limiting CO_2 emissions from new electric utility generating units (EGUs) fired by fossil fuels. The proposed requirements, which are limited to new sources, would require new fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of CO_2 per MWh. The EPA did not propose standards of performance for existing EGUs whose CO_2 emissions increase as a result of installation of pollution controls for conventional pollutants. While Idaho Power does not expect the new NSPS to impact its existing generation facilities, if promulgated the new rule would impact the cost effectiveness of developing new generation units.

State and Regional GHG Initiatives: On a regional level, there are a number of initiatives, including the Western Regional Climate Action Initiative, considering market-based mechanisms to reduce GHG emissions. Separately, in August 2007 the Oregon legislature enacted legislation setting goals of reducing GHG levels to 10 percent below 1990 levels by 2020 and at least 75 percent below 1990 levels by 2050. Oregon imposes GHG emission reporting requirements on facilities emitting 2,500 metric tons or more of CO_2 equivalent annually. The mechanism was implemented in two phases, with Title V sources and entities with an air discharge permit required to start reporting 2009 emissions in 2010 and all other sources required to start reporting 2010 emissions in 2011. The Boardman coal-fired power plant, in which Idaho Power is a 10-percent owner, is subject to and in compliance with Oregon's GHG reporting requirements.

The State of Idaho has not passed legislation specifically regulating GHGs, but in May 2007 Governor Otter issued Executive Order 2007-05, which directed the Idaho Department of Environmental Quality to work with the state government to implement GHG reductions within each agency, complete a statewide emissions inventory, and provide recommendations to the Governor, among other tasks. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but are members of the Climate Registry, a national, voluntary GHG emission reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emission reporting system across states, provinces, and tribes to track GHG emissions nationally. All states for which Idaho Power has traditional fuel plants operating (i.e. Idaho, Oregon, Wyoming, and Nevada) are members of the Climate Registry.

Idaho Power's Voluntary GHG Reduction Initiatives: Despite the current absence of a national mandatory GHG reduction program, Idaho Power is engaged in voluntary GHG emission intensity reduction efforts. Also, Idaho Power has voluntarily submitted information to the Carbon Disclosure Project, an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world. Idaho Power's estimated CO_2 emission intensity (lbs/MWh) from its generation facilities as submitted to the Carbon Disclosure Project was 672, 1,051, 1,004, 1,097, and 1,150 lbs/MWh for 2011, 2010, 2009, 2008, and 2007, respectively.

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In 2010, Idaho Power and Ida-West together ranked as the 37th lowest emitter of CO_2 per MWh produced and the 35th lowest emitter of CO_2 by tons of emissions among the nation's 100 largest electricity producers, according to a July 2012 collaborative report from Ceres, the Natural Resources Defense Council, and other entities using publicly reported 2010 generation and emissions data. According to the report, out of the 100 companies named, Idaho Power and Ida-West together ranked as the 58th largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

Public Nuisance-Related Suits for GHGs: In June 2011, the U.S. Supreme Court held that federal courts do not have jurisdiction to hear federal common law nuisance claims relating to GHG emissions because the legal authority to regulate GHGs has been delegated by Congress to the EPA, not to federal courts. The Court did not address, however, whether state common law nuisance claims would also be barred by the federal CAA. Accordingly, the Supreme Court's decision did not completely eliminate the potential for future nuisance-related suits for GHG emissions.

Clean Air Act Developments

Overview: In addition to the CAA developments related to GHG emissions described above, several other regulatory programs developed under the CAA impact Idaho Power. These include the final Utility Maximum Available Control Technology (MACT) rule, National Ambient Air Quality Standards (NAAQS), NSR/PSD Rules, and the Regional Haze Rule.

Final MACT Rule: The CAA requires the EPA to develop industry-based standards to control emissions of hazardous air pollutants, or HAPs. These standards are referred to as the MACT rules. In February 2012, the EPA issued final MACT rules to control emissions of mercury and other HAPs from coal- and oil-fired EGUs under the CAA and new NSPS for fossil fuel-fired EGUs. The regulations impose MACT and NSPS on all coal-fired EGUs and replace the former Clean Air Mercury Rule. Specifically, the regulations set numeric emission limitations on coal-fired EGUs for total particulate matter (a surrogate for non-mercury HAPs), hydrogen chloride, and mercury. In addition, the regulations impose a work practice standard for organic HAPs, including dioxins and furans. For the revised NSPS, for EGUs commencing construction of a new source after publication of the final rule, the EPA has established amended emission limitations for particulate matter, sulfur dioxide, and nitrogen oxides. The compliance deadline for the new MACT rules could be as early as 2015. Mercury continuous emission monitoring systems have been installed on all of the coal-fired units at the Jim Bridger, Boardman, and Valmy generating plants in compliance with the NSPS rule. Idaho Power is reviewing the MACT final rule and is in the process of determining how these regulations will impact the Bridger, Boardman, and Valmy generating plants, including whether those coal-fired plants can meet HAP limits with current and planned control technologies. While Idaho Power does not expect the new NSPS to impact its existing generation facilities, the new rules would impact the cost effectiveness of developing new EGUs.

NAAQS: The CAA requires the EPA to set ambient air quality standards for six "criteria" pollutants considered harmful to public health and the environment. These six pollutants are carbon monoxide, lead, ozone, particulate matter, nitrogen dioxide, and sulfur dioxide. States are then required to develop emission reduction strategies through State Implementation Plans, or SIPs, based on attainment of these ambient air quality standards. Recent developments related to three of these pollutants - $PM_{2.5}$, NO_x, and SO_2 are relevant to Idaho Power.

- Particular Matter ($PM_{2.5}$). In 1997, the EPA adopted NAAQS for fine particulate matter of less than 2.5 micrometers in diameter ($PM_{2.5}$ standard), setting an annual limit of 15 micrograms per cubic meter ($\mu g/m^3$), calculated as a three-year average. In 2006, the EPA adopted a 24-hour NAAQS for $PM_{2.5}$. of 35 $\mu g/m^3$. All of the counties in Idaho, Nevada, Oregon, and Wyoming in which Idaho Power's power plants are located have been designated as "attainment" with these $PM_{2.5}$ standards. However, on December 14, 2012, the EPA released final revisions to the $PM_{2.5}$ NAAQS. The revised annual standard is 12 $\mu g/m^3$, calculated as a three-year average. The EPA retained the existing 24-hour standard of 35 $\mu g/m^3$. Now that the PM2.5 NAAQS has been finalized, states will make recommendations to the EPA regarding designations of attainment or non-attainment. States also will be required to review, modify, and supplement their SIPs, which could require the installation of additional controls and requirements for Idaho Power's coal-fired generation plants, depending on the level ultimately finalized. The revised NAAQS would also have an impact on the applicable air permitting requirements for new and modified facilities. The EPA has stated that it plans to issue nonattainment designations by late 2014, with states having until 2020 to comply with the standards.

NO_x. In 2010, the EPA adopted a new NAAQS for NO_x at a level of 100 parts per billion averaged over a 1-hour period. In connection with the new NAAQS, in February 2012 the EPA issued a final rule designating all of the counties in Idaho, Nevada, Oregon, and Wyoming where Idaho Power owns or has an interest in a natural gas or coal-fired power plant as “unclassifiable/attainment” for NO_x. The EPA indicated it will review the designations after 2015, when three years of air quality monitoring data are available, and may formally designate the counties as attainment or non-attainment for NO_x. A designation of non-attainment may increase the likelihood that Idaho Power would be

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required to install costly pollution control technology at one or more of its plants. As the designations have not yet been finalized, as of the date of this report Idaho Power is unable to predict the impact of the NAAQS for NO_x on its operations. However, the costs of installation and implementation of any additional pollution reduction technology could be substantial.

- SO_2. In 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. In 2011, the states of Idaho, Nevada, Oregon, and Wyoming sent letters to the EPA recommending that all counties in these states be classified as "unclassifiable" under the new one-hour SO_2 NAAQS because of a lack of definitive monitoring and modeling data.

Because the EPA has not yet completed the designation of areas as attaining or not attaining these new NAAQS, Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations, though it does expect at least some increases in capital and operating costs from the standards.

Regional Haze Rules: In accordance with federal regional haze rules under the CAA, coal-fired utility boilers are subject to regional haze - best available retrofit technology (RH BART) if they were built between 1962 and 1977 and affect any "Class I" (wilderness) areas. This includes all four units at the Jim Bridger and the Boardman coal-fired plants.

Jim Bridger Plant: In December 2009, the Wyoming Department of Environmental Quality (WDEQ) issued a RH BART permit to PacifiCorp as the operator of the Jim Bridger plant. The WDEQ determined that low NO_x burners with over-fire air is RH BART for NO_x for all four Bridger units and that RH BART is not required for SO_2 at the Jim Bridger plant. As part of the WDEQ's long term strategy for regional haze, the permit requires that PacifiCorp install selective catalytic reduction (SCR) for NO_x control at Jim Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively, and submit an application by January 15, 2015 to install add-on NO_x controls at Jim Bridger Units 1 by 2022 and 2 by 2021. PacifiCorp has installed low NO_x burners and SO_2 scrubber upgrades at the plant. The SO_2 scrubber upgrade project has been completed on all four Jim Bridger units. Idaho Power spent approximately $1 million in 2012 for its share of these pollution control projects. Idaho Power's estimated share of the cost to install SCR on Jim Bridger Units 3 and 4 is $120 million. In addition to the installation costs, installation of SCR could require extended maintenance outages. Design and cost estimates for add-on NO_x controls at Jim Bridger Units 1 and 2 are not yet available.

In November 2010, PacifiCorp and the WDEQ signed a settlement agreement under which PacifiCorp agreed to the timing and nature of controls described above. The settlement agreement is conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze State Implementation Plan (RH SIP) that are consistent with the terms of the settlement agreement. In May 2012, the EPA proposed to partially reject Wyoming's regional haze SIP for NO_x reduction at the Jim Bridger plant, instead proposing to substitute the EPA's own RH BART determination and its Federal Implementation Plan (FIP). The EPA's primary proposal would result in an acceleration of the installation of SCR additions at Bridger Units 1 and 2 to within five years after the FIP, or a SIP revised to be consistent with the proposed FIP, is adopted by the EPA. In November 2012, the EPA approved the general provisions of the WDEQ's RH SIP. However, in December 2012 the EPA announced that it would re-propose the plant-specific NO_x control provisions of its RH FIP in March 2013 and would not finalize the RH FIP until September 2013.

Boardman Plant: Following the introduction of various plans and an extensive public process, in December 2010 the Oregon Environmental Quality Commission (OEQC) approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. The rules implementing the plan were approved by the EPA and published in the Federal Register in July 2011, and require the installation of a number of emissions controls. The new rules repeal the OEQC's 2009 BART rule, which would have allowed continued operation of the Boardman plant through at least 2040 with installation of a more extensive suite of emissions controls. The estimated combined total capital cost of the required controls under the plan approved by the OEQC for controlling mercury, NO_x and SO_2 is approximately $60 million. Idaho Power is a 10 percent owner of the Boardman plant, and thus Idaho Power's estimated share of the capital cost is $6 million, which is in addition to normal capital expenditures and maintenance costs. As of December 31, 2012, Idaho Power had incurred charges of $3.8 million, including AFUDC, of its total estimated share of the capital cost for the new controls.

NSR / PSD: NSR/PSD is a preconstruction permitting program that requires a stationary source of air pollution to obtain a permit before beginning construction. The purpose of the program is to ensure that air quality is not significantly degraded by the addition of new and modified facilities, industrial boilers, and power plants. Under current NSR provisions of the CAA, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory equivalent before beginning the construction of a stationary source that will emit regulated pollutants, or before modifying an existing stationary source that will increase its emission levels. Since 1999, the EPA and the U.S. Department of Justice have been pursuing a national enforcement initiative focused on the compliance status of coal-fired power plants with the NSR permitting requirements and NSPS under the CAA. This initiative has resulted in both enforcement litigation and significant settlements with a large number of public utilities and other owners of coal-fired power plants across the country. As part of an industry-wide assessment of compliance with NSR and NSPS, EPA has sought information from a number of utilities regarding their coal-fired generating facilities. In 2003, the EPA sent information requests pursuant to the CAA to the Jim Bridger plant, seeking information relevant to NSR and NSPS compliance. Additional requests were received by the Valmy plant in 2009 and the Boardman plant in 2008, with a follow up request for information in 2009. In September 2010, the EPA issued a Notice of Violation to Portland General Electric Company, the operator of the Boardman plant, alleging that PGE violated the NSPS under Section 111 of the CAA and operating permit requirements under Title V of the CAA at the Boardman coal-fired plant as a result of certain modifications made to the plant in 1998 and 2004. To date, the EPA has not taken action on the Notice of Violation, and a related private lawsuit under the CAA was settled in 2011.

Potential Regulation of Coal Combustion Residuals (CCRs)

The Resource Conservation and Recovery Act is a federal statute regulating the generation, treatment, storage, and disposal of solid and hazardous wastes. In December 2008, the breach of a dike at the Tennessee Valley Authority's Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties. In response, in June 2010 the EPA proposed regulations governing the disposal and management of CCRs. The EPA requested comments on two options for regulating CCRs. The first option would regulate CCRs as a new “special waste” subject to many of the requirements for hazardous waste, while the second would regulate CCRs in a manner similar to typical solid waste, subject to fewer and less stringent requirements. To date the EPA has not issued final regulations. Both of the EPA's proposed options represent a shift toward more comprehensive and potentially more expensive requirements for CCR management and disposal. If this or other new legislation or regulations increase the cost of managing and disposing of CCRs or create additional liability with respect to historic disposal practices, they could have an adverse impact on Idaho Power's consolidated financial position, operations, or cash flows. However, the financial and operational consequences cannot be determined until final legislation is passed or regulations are issued.

Regulation of Polychlorinated Biphenyls (PCBs)

The Toxic Substances Control Act is a federal statute providing the EPA with the authority to, among other things, require use restrictions relating to chemical substances including PCBs. Generally, PCBs are prohibited from use, but some uses of PCBs - such as in electrical equipment - remain authorized under certain conditions. In April 2010, the EPA issued an advance notice of proposed rulemaking stating that it is considering revisiting the authorization allowing the continued use of PCBs in equipment. If new regulations require the replacement of existing equipment, they could have an adverse effect on IDACORP's and Idaho Power's financial condition and results of operations. However, the financial and operational consequences cannot be determined until final regulations are issued. Idaho Power currently records asset retirement obligation liabilities and associated regulatory assets for the estimated retirement costs of equipment containing PCBs. Final regulations could accelerate Idaho Power's estimated timing for the retirement of equipment with PCBs.

CWA - Potential Section 316(b) Regulation of Cooling Water Intake Structures

The CWA generally prohibits the discharge of any "pollutant" from a point source into waters of the United States without a permit. Pollutants are broadly defined to include changes in temperature. Section 316(b) of the CWA requires that National Pollutant Discharge Elimination System permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures employ the best technology available (BTA) to minimize harmful impacts on the environment, such as the removal of fish, fish larvae, marine mammals and other aquatic organisms from waters of the U.S.

In March 2011, the EPA issued a proposed rule that would establish requirements under Section 316(b) of the CWA for all existing power generation facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed rule establishes national requirements applicable to cooling water intake structures at these facilities that reflect the BTA for minimizing adverse environmental impacts. An existing facility may choose one of two options for meeting BTA requirements for impingement mortality under this proposed rule. The owner or operator may monitor to show the specified performance standards for impingement mortality of fish and shellfish have been met, or they may demonstrate that the intake velocity meets specified design criteria. For entrainment mortality, this proposed rule establishes requirements for studies and information as part of the permit application, and then establishes a process by which the BTA for entrainment mortality would be implemented at each facility. Since issuing the proposed rule, EPA has collected more than 80 studies from

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the public with additional biological data, some of which may help address the intent of the proposed rule to reduce damage to ecosystems while accommodating site-specific circumstances and providing cost-effective options for compliance. Based on the qualification criteria, Idaho Power expects that the new requirements would apply to the Jim Bridger plant, but it is unable to determine the potential increased costs that may result from implementation of the rule until the final rule is issued and cost studies are performed. The EPA has announced it intends to finalize the rules by June 2013.
Idaho Power is also addressing CWA issues associated with the relicensing of its HCC. See “Relicensing of Hydroelectric Projects” in this MD&A for additional information on the impact of the CWA on that relicensing effort.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

When preparing financial statements in accordance with generally accepted accounting principles (GAAP), IDACORP’s and Idaho Power’s management must apply accounting policies and make estimates that affect the reported amounts of assets, liabilities, revenues, and expenses and related disclosure of contingent assets and liabilities. These estimates often involve judgment about factors that are difficult to predict and are beyond management’s control. Management adjusts these estimates based on historical experience and on other assumptions and factors that are believed to be reasonable under the circumstances. Actual amounts could materially differ from the estimates. Management believes the accounting policies and estimates discussed below are the most critical 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 and may change in subsequent periods.

Accounting for Rate Regulation

Entities that meet specific conditions are required by GAAP to reflect the impact of regulatory decisions in their consolidated financial statements and to defer certain costs as regulatory assets until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities. Idaho Power must satisfy three conditions to apply regulatory accounting: (1) an independent regulator must set rates; (2) the regulator must set the rates to cover specific costs of delivering service; and (3) the service territory must lack competitive pressures to reduce rates below the rates set by the regulator.

Idaho Power has determined that it meets these conditions, and its financial statements reflect the effects of the different rate-making principles followed by the jurisdictions regulating Idaho Power. The primary effect of this policy is that Idaho Power had recorded $1.2 billion of regulatory assets and $386 million of regulatory liabilities at December 31, 2012. Idaho Power expects to recover these regulatory assets from customers through rates and refund these regulatory liabilities to customers through rates, but recovery or refund is subject to final review by the regulatory bodies. If future recovery or refund of these amounts ceases to be probable, or if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power could be required to eliminate those regulatory assets or liabilities. Either circumstance could have a material effect on Idaho Power’s financial condition or results of operations.

Income Taxes

IDACORP and Idaho Power use judgment and estimation in developing the provision for income taxes and the reporting of tax-related assets and liabilities. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income taxes could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities.

Idaho Power provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes for other items are provided for the temporary differences between the income tax and financial accounting treatment of such items. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax temporary differences where the prescribed regulatory accounting methods, or flow-through, direct Idaho Power to recognize the tax impacts currently for rate making and financial reporting.

Refer to Note 1 - “Summary of Significant Accounting Policies” and Note 2 - “Income Taxes” to the consolidated financial statements included in this report for additional information relating to income taxes.

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Asset Impairment

Available-for-sale Securities: Idaho Power is required to evaluate available-for-sale securities periodically to determine whether a decline in fair value below cost is other than temporary. If the decline in fair value is other than temporary, the cost of the investment is written down to fair value and the loss is recorded as a realized loss. Two significant factors that are considered when evaluating investments for impairment are the length of time and the extent to which the market value has been less than cost.

Idaho Power has investments in four mutual funds that experienced a significant decline in fair value in 2008. Idaho Power's investments had lost between 32 percent and 43 percent of their value, primarily during the stock market downturn in September and October 2008, and had been in loss positions from 6 to 12 months at December 31, 2008. Because of the severity of the declines in value, Idaho Power determined that the loss in value was other-than-temporary and recorded a pre-tax loss of $6.8 million in the fourth quarter of 2008. At December 31, 2012 and 2011, the fair values of these investments were at or above their new cost bases and no impairment was recorded.

Equity-Method Investments: IFS has affordable housing investments with a net book value of $51 million at December 31, 2012, and Ida-West has investments in four joint ventures that own electric power generation facilities. Except for one investment which is consolidated, these investments are accounted for under the equity method of accounting and have a net book value of $12 million. The standard for determining whether impairment must be recorded for these investments is whether the investment has experienced a loss in value that is considered an other-than-temporary decline in value. Impairment analyses are performed on these investments when indicators of impairment are noted. An immaterial impairment was recorded on one of the Ida-West joint ventures in 2011, and no impairments were recorded in 2012 or in 2010. These estimates required IDACORP to make assumptions about future 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.

Pension and Other Postretirement Benefits

Idaho Power maintains a tax-qualified, noncontributory defined benefit pension plan covering most employees, an unfunded nonqualified deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP), and a postretirement benefit plan (consisting of health care and death benefits).

The costs IDACORP and Idaho Power record for these plans depend on the provisions of the plans, changing employee demographics, actual returns on plan assets, and several assumptions used in the actuarial valuations from which the expense is derived. 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 used to develop the actuarial assumptions are 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 Idaho Power determined the discount rate for each plan through the construction of hypothetical portfolios of bonds selected from high-quality corporate bonds available as of December 31, 2012, with maturities matching the projected cash outflows of the plans. The discount rate used to calculate the 2013 pension expense will be decreased to 4.2 percent from the 4.9 percent used in 2012.

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 Idaho Power believes 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 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. The long-term rate of return used to calculate the 2013 pension expense will be 7.75 percent, which is the same assumption as was used for 2012.

Gross net periodic pension and other postretirement benefit cost for these plans totaled $51 million, $39 million, and $39 million for the years ended December 31, 2012, 2011, and 2010, respectively, including amounts deferred as regulatory assets (see discussion below) and amounts allocated to capitalized labor. For 2013, gross pension and other postretirement benefit

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costs are expected to total approximately $57 million, which takes into account the change 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 the discount rate and rate-of-return on plan assets actuarial assumptions on historical and future pension and postretirement expense:

	Discount rate		Rate of return	
	2013	2012	2013	2012
	(millions of dollars)			
Effect of 0.5% rate increase on net periodic benefit cost	$(6.9)	$(5.7)	$(2.5)	$(2.2)
Effect of 0.5% rate decrease on net periodic benefit cost	8.0	6.6	2.4	2.2

Additionally a 0.5 percent increase in the plans' discount rates would have resulted in a $67 million decrease in the combined benefit obligations of the plans as of December 31, 2012. A 0.5 percent decrease in the plans' discount rates would have resulted in a $76 million increase in the combined benefit obligations of the plans as of December 31, 2012.

Idaho Power made contributions of $60 million, $18.5 million, and $44.3 million to the pension plan in 2010, 2011, and 2012 respectively. Idaho Power's required contributions to the pension plan during 2013 are estimated to be zero. Under the SMSP, Idaho Power makes payments directly to participants in the plan. Benefit payments are expected to be $3.7 million in 2013 and averaged $3.3 million per year from 2010 to 2012. Postretirement benefit plan contributions are expected to be $0.3 million in 2013, and averaged $0.9 million from 2010 to 2012.

The IPUC has authorized Idaho Power to account for its defined benefit pension plan expense on a cash basis, and to defer and account for accrued pension expense as a regulatory asset. The IPUC acknowledged that it is appropriate for Idaho Power to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. In 2007, Idaho Power began deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. At December 31, 2012, a total of $65 million of expense was deferred as a regulatory asset. Approximately $26 million is expected to be deferred in 2013. Idaho Power recorded pension expense in 2012, 2011, and 2010 of $34 million, $34 million, and $5 million, respectively.

Refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report for additional information relating to pension and postretirement benefit plans.

Contingent Liabilities

An estimated loss from a loss contingency is charged to income if (a) it is probable that a liability had been incurred at the date of the financial statements and (b) the amount of the loss can be reasonably estimated. If a probable loss cannot be reasonably estimated, no accrual is recorded but disclosure of the contingency in the notes to the financial statements is required. Gain contingencies are not recorded until realized.

IDACORP and Idaho Power have a number of unresolved issues related to regulatory and legal matters. If the recognition criteria 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.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

There have been no recently issued accounting pronouncements that have had or are expected to have a material impact on IDACORP's or Idaho Power's results of operations or financial condition. See Note 1 - “Summary of Significant Accounting Policies” to the consolidated financial statements included in this report for a summary of significant accounting policies.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and Idaho Power are exposed to 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, 2012.

Interest Rate Risk

IDACORP and Idaho Power manage interest expense and short- and long-term liquidity through 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, 2012, IDACORP and Idaho Power had $96.6 million and $24.1 million, respectively, in net floating-rate debt. The fair market value of this debt was $96.6 million and $24.1 million, respectively. Assuming no change in financial structure, if variable interest rates were to average one percentage-point higher than the average rate on December 31, 2012, interest rate expense would increase and pre-tax earnings would decrease by approximately $1.0 million for IDACORP and $0.2 million for Idaho Power.

Fixed Rate Debt: As of December 31, 2012, IDACORP and Idaho Power each had $1.5 billion in fixed rate debt, with a fair market value equal to $1.8 billion. These instruments are fixed rate and, therefore, do not expose the companies to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $147 million for both IDACORP and Idaho Power if interest rates were to decline by one percentage point from their December 31, 2012 levels.

Commodity Price Risk

Idaho Power's exposure to changes in commodity prices is related to its ongoing utility operations that produce electricity to meet the demand of its retail electric customers. To supplement its generation resources and balance its supply of power with the demand of its retail customers, Idaho Power participates in the wholesale marketplace. These purchased power arrangements allow Idaho Power to respond to fluctuations in the demand for electricity and variability in generating plant operations. Idaho Power also enters into arrangements for the purchase of fuel for natural gas and coal-fired generating plants. Idaho Power anticipates that the additional volume of natural gas needed to operate the Langley Gulch power plant will increase its exposure in the future to natural gas commodity price risk. These contracts for the purchase of power and fuel expose Idaho Power to commodity price risk.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. The weather is a major uncontrollable factor affecting the local and regional demand for electricity and the availability and cost of production. Other factors include the occurrence and timing of demand peaks due to seasonal, daily, and hourly power demand; power supply; power transmission capacity; changes in federal and state regulation and compliance obligations; fuel supplies; and market liquidity.

Idaho Power’s exposure to commodity price risk is largely offset by the PCA mechanisms in Idaho and Oregon. Therefore, the primary objectives of Idaho Power’s energy purchase and sale activity are 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. Idaho Power has adopted a risk management program, which has been reviewed and accepted by the IPUC, designed to reduce exposure to power supply cost-related uncertainty, further mitigating commodity price risk. Idaho Power's Energy Risk Management Policy (Policy) and associated standards implementing the Policy describe a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of selected Idaho Power officers and other senior staff, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to the Idaho Power Board of Directors and to the CAG, and Idaho Power's Audit Committee is responsible for approving the Policy and associated standards. The RMC is also responsible for conducting an ongoing general assessment of the appropriateness of Idaho Power's strategies for energy risk management activities. In its risk management process, Idaho Power considers both demand-side and supply-side options consistent with its IRP. The primary tools for risk mitigation are physical and financial forward power transactions and fueling alternatives for utility-owned generation resources. Idaho Power does not engage in trading activities for non-retail purposes.

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The Policy requires monitoring monthly volumetric electricity position and total monthly 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 based on factors such as forecasted resource availability, stream flows, and load, and orders risk mitigating actions, including resource optimization and hedging strategies, dictated by the limits stated in the Policy to bring exposures within pre-established risk guidelines. The RMC evaluates the actions initiated by Power Supply for consistency and compliance with the Policy. Idaho Power 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.

Credit Risk

Idaho Power is subject to credit risk based on its activity with market counterparties. Idaho Power 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. Idaho Power mitigates this exposure by actively establishing credit limits; measuring, monitoring, and reporting credit risk using appropriate contractual arrangements; and transferring of credit risk through the use of financial guarantees, cash, or letters of credit. Idaho Power maintains a current list of acceptable counterparties and credit limits.

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2012, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on Idaho Power’s unsecured debt to below investment grade, Idaho Power could be subject to requests by its wholesale counterparties to post performance assurance collateral. Counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power’s current energy and fuel portfolio and market conditions as of December 31, 2012, the approximate amount of collateral that could be requested upon a downgrade to below investment grade is approximately $7.2 million. Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements.

Idaho Power is obligated to provide service to all electric customers within its service area. Credit risk for Idaho Power’s retail customers is managed by credit and collection policies that are governed by rules issued by the IPUC or OPUC. Idaho Power records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. Idaho Power will continue to monitor the impact of the current economic conditions on nonpayment from customers and will make any necessary adjustments to its provision for uncollectible accounts.

Idaho utility customer relations rules prohibit Idaho Power from terminating electric service during the months of December through February to any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, elderly, or infirm persons. Idaho Power’s provision for uncollectible accounts could be affected by changes in future prices as well as changes in IPUC or OPUC regulations.

Equity Price Risk

IDACORP and Idaho Power are exposed to price fluctuations in equity markets, primarily through their defined benefit pension plan assets, a mine reclamation trust fund owned by an equity-method investment of Idaho Power, and other equity investments at Idaho Power. During 2012, the fair value of the defined benefit pension plan’s assets increased; however, increases in the benefit liabilities were greater than the increases in the plan’s assets, therefore resulting in an increase in future amounts required to be contributed to the plan. A hypothetical ten percent decrease in equity prices would result in an approximate $3.2 million decrease in the fair value of financial instruments that are classified as available-for-sale securities as of December 31, 2012.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Financial Statement Schedules

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IDACORP, Inc.
Consolidated Statements of Income

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$937,765	$834,545	$870,371
Off-system sales	61,534	101,602	78,133
Other revenues	77,426	86,581	84,548
Total electric utility revenues	1,076,725	1,022,728	1,033,052
Other	3,937	4,028	2,977
Total operating revenues	1,080,662	1,026,756	1,036,029
Operating Expenses:			
Electric utility:			
Purchased power	196,935	163,336	143,769
Fuel expense	159,413	131,542	159,673
Power cost adjustment	(61,090)	38,497	51,226
Other operations and maintenance	349,033	338,640	293,925
Energy efficiency programs	27,300	37,663	44,184
Depreciation	123,941	119,789	115,921
Taxes other than income taxes	30,489	28,895	24,046
Total electric utility expenses	826,021	858,362	832,744
Other	12,039	13,042	11,474
Total operating expenses	838,060	871,404	844,218
Operating Income	242,602	155,352	191,811
Allowance for Equity Funds Used During Construction	22,433	25,484	16,551
(Losses) Earnings of Unconsolidated Equity-Method Investments	(328)	798	3,008
Other Income, Net	4,209	4,621	5,473
Interest Expense:			
Interest on long-term debt	78,922	79,349	80,490
Other interest	6,876	5,510	5,299
Allowance for borrowed funds used during construction	(11,929)	(13,333)	(10,675)
Total interest expense, net	73,869	71,526	75,114
Income Before Income Taxes	195,047	114,729	141,729
Income Tax Expense (Benefit)	26,113	(52,133)	(731)
Net Income	168,934	166,862	142,460
Adjustment for (income) loss attributable to noncontrolling interests	(173)	(169)	338
Net Income Attributable to IDACORP, Inc.	$168,761	$166,693	$142,798
Weighted Average Common Shares Outstanding - Basic (000's)	49,930	49,457	48,193
Weighted Average Common Shares Outstanding - Diluted (000's)	50,010	49,558	48,340
Earnings Per Share of Common Stock:			
Earnings Attributable to IDACORP, Inc. - Basic	$3.38	$3.37	$2.96
Earnings Attributable to IDACORP, Inc. - Diluted	$3.37	$3.36	$2.95
Dividends Declared Per Share of Common Stock	$1.37	$1.20	$1.20

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,		
	2012	2011	2010
	(thousands of dollars)		
Net Income	$168,934	$166,862	$142,460
Other Comprehensive Income:			
Net unrealized holding gains (losses) arising during the year, net of tax of $1,006, ($257), and $738	1,567	(400)	1,149
Unfunded pension liability adjustment, net of tax of ($4,532), ($1,062), and ($1,573)	(7,061)	(1,654)	(2,450)
Total Comprehensive Income	163,440	164,808	141,159
Comprehensive (income) loss attributable to noncontrolling interests	(173)	(169)	338
Comprehensive Income Attributable to IDACORP, Inc.	$163,267	$164,639	$141,497

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2012	2011
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$26,527	$27,813
Receivables:		
Customer (net of allowance of $1,551 and $1,239, respectively)	66,111	66,296
Other (net of allowance of $322 and $196, respectively)	23,608	8,197
Income taxes receivable	1,753	421
Accrued unbilled revenues	51,448	46,441
Materials and supplies (at average cost)	51,037	46,490
Fuel stock (at average cost)	42,388	47,865
Prepayments	12,823	12,405
Deferred income taxes	56,532	16,159
Current regulatory assets	30,078	34,279
Other	4,948	4,606
Total current assets	367,253	310,972
Investments	189,020	199,931
Property, Plant and Equipment:		
Utility plant in service	4,915,772	4,466,873
Accumulated provision for depreciation	(1,703,159)	(1,677,609)
Utility plant in service - net	3,212,613	2,789,264
Construction work in progress	298,470	591,475
Utility plant held for future use	7,101	6,974
Other property, net of accumulated depreciation	17,847	18,877
Property, plant and equipment - net	3,536,031	3,406,590
Other Assets:		
American Falls and Milner water rights	17,909	20,015
Company-owned life insurance	22,646	24,060
Regulatory assets	1,132,960	953,068
Long-term receivables (net of allowance of $1,260 and $2,743, respectively)	4,437	5,621
Other	49,260	40,352
Total other assets	1,227,212	1,043,116
Total	$5,319,516	$4,960,609

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2012	2011
	(thousands of dollars)	
Liabilities and Equity		
Current Liabilities:		
Current maturities of long-term debt	$71,064	$101,064
Notes payable	69,700	54,200
Accounts payable	90,165	81,769
Income taxes accrued	1,005	505
Interest accrued	22,311	21,797
Accrued compensation	42,343	39,726
Current regulatory liabilities	30,277	29,738
Other	24,438	39,448
Total current liabilities	351,303	368,247
Other Liabilities:		
Deferred income taxes	894,616	772,047
Regulatory liabilities	355,362	332,057
Pension and other postretirement benefits	423,409	363,209
Other	65,228	75,805
Total other liabilities	1,738,615	1,543,118
Long-Term Debt	1,466,632	1,387,550
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (shares authorized 120,000,000; 50,158,486 and 49,964,172 shares issued, respectively)	834,922	828,389
Retained earnings	940,968	840,916
Accumulated other comprehensive loss	(17,116)	(11,622)
Treasury stock (1,817 and 12,177 shares at cost, respectively)	(21)	(29)
Total IDACORP, Inc. shareholders' equity	1,758,753	1,657,654
Noncontrolling interests	4,213	4,040
Total equity	1,762,966	1,661,694
Total	$5,319,516	$4,960,609

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,		
	2012	2011	2010
	(thousands of dollars)		
Operating Activities:			
Net income	$168,934	$166,862	$142,460
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	128,611	124,659	121,849
Deferred income taxes and investment tax credits	26,293	(52,913)	41,742
Changes in regulatory assets and liabilities	(53,468)	68,045	46,510
Pension and postretirement benefit plan expense	45,230	45,223	14,728
Contributions to pension and postretirement benefit plans	(47,695)	(22,088)	(65,601)
Losses (earnings) of unconsolidated equity-method investments	328	(798)	(3,008)
Distributions from unconsolidated equity-method investments	18,546	2,500	6,530
Allowance for equity funds used during construction	(22,433)	(25,484)	(16,551)
Other non-cash adjustments to net income, net	5,919	4,487	3,061
Change in:			
Accounts receivable and prepayments	(3,919)	(2,232)	14,243
Accounts payable and other accrued liabilities	10,580	5,428	4,014
Taxes accrued/receivable	(604)	15,113	(14,216)
Other current assets	(4,077)	(19,684)	3,848
Other current liabilities	(8,500)	2,171	13,682
Other assets	(7,064)	4,330	(3,662)
Other liabilities	(7,412)	(5,376)	(4,229)
Net cash provided by operating activities	249,269	310,243	305,400
Investing Activities:			
Additions to property, plant and equipment	(239,761)	(337,765)	(338,252)
Proceeds from the sale of utility assets	—	—	18,982
Proceeds from the sale of emission allowances and RECs	2,739	6,314	6,408
Investments in affordable housing	(139)	(1,558)	(13,390)
Investments in unconsolidated affiliates	—	(2,645)	—
Purchase of available-for-sale securities	(7,000)	—	(7,000)
Other	340	3,296	4,918
Net cash used in investing activities	(243,821)	(332,358)	(328,334)
Financing Activities:			
Issuance of long-term debt	150,000	—	200,000
Retirement of long-term debt	(101,064)	(121,064)	(1,064)
Dividends on common stock	(68,928)	(59,668)	(57,872)
Net change in short-term borrowings	15,500	(12,700)	13,150
Issuance of common stock	4,882	17,501	48,644
Acquisition of treasury stock	(2,062)	(1,933)	(869)
Other	(5,062)	(885)	(3,365)
Net cash (used in) provided by financing activities	(6,734)	(178,749)	198,624
Net (decrease) increase in cash and cash equivalents	(1,286)	(200,864)	175,690
Cash and cash equivalents at beginning of the year	27,813	228,677	52,987
Cash and cash equivalents at end of the year	$26,527	$27,813	$228,677
Supplemental Disclosure of Cash Flow Information:			

Cash paid (received) during the year for:			
Income taxes	$1,451	$(12,405)	$(27,112)
Interest (net of amount capitalized)	$70,887	$70,969	$69,049
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$26,882	$26,331	$33,949
Investments in affordable housing	$—	$—	$1,509

The accompanying notes are an integral part of these statements.

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IDACORP, Inc.
Consolidated Statements of Equity

	Year ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$828,389	$807,842	$756,475
Issued	4,882	17,501	48,644
Other	1,651	3,046	2,723
Balance at end of year	834,922	828,389	807,842
Retained Earnings:			
Balance at beginning of year	840,916	733,879	649,180
Net income attributable to IDACORP, Inc.	168,761	166,693	142,798
Common stock dividends ($1.37, $1.20, and $1.20 per share, respectively)	(68,709)	(59,656)	(58,099)
Balance at end of year	940,968	840,916	733,879
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(11,622)	(9,568)	(8,267)
Net unrealized holding gain (loss) on securities (net of tax)	1,567	(400)	1,149
Unfunded pension liability adjustment (net of tax)	(7,061)	(1,654)	(2,450)
Balance at end of year	(17,116)	(11,622)	(9,568)
Treasury Stock:			
Balance at beginning of year	(29)	(40)	(53)
Issued	2,070	1,944	882
Acquired	(2,062)	(1,933)	(869)
Balance at end of year	(21)	(29)	(40)
Total IDACORP, Inc. shareholders' equity at end of year	1,758,753	1,657,654	1,532,113
Noncontrolling Interests:			
Balance at beginning of year	4,040	3,871	4,209
Net income (loss) attributable to noncontrolling interests	173	169	(338)
Balance at end of year	4,213	4,040	3,871
Total equity at end of year	$1,762,966	$1,661,694	$1,535,984

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, 2012	2011	2010
	(thousands of dollars)		
Operating Revenues:			
General business	$937,765	$834,545	$870,371
Off-system sales	61,534	101,602	78,133
Other revenues	77,426	86,581	84,548
Total operating revenues	1,076,725	1,022,728	1,033,052
Operating Expenses:			
Operation:			
Purchased power	196,935	163,336	143,769
Fuel expense	159,413	131,542	159,673
Power cost adjustment	(61,090)	38,497	51,226
Other operations and maintenance	349,033	338,640	293,925
Energy efficiency programs	27,300	37,663	44,184
Depreciation	123,941	119,789	115,921
Taxes other than income taxes	30,489	28,895	24,046
Total operating expenses	826,021	858,362	832,744
Income from Operations	250,704	164,366	200,308
Other Income (Expense):			
Allowance for equity funds used during construction	22,433	25,484	16,551
Earnings of unconsolidated equity-method investments	9,412	9,018	11,281
Other expense, net	(4,982)	(4,462)	(2,868)
Total other income	26,863	30,040	24,964
Interest Charges:			
Interest on long-term debt	78,922	79,349	80,490
Other interest	6,436	5,039	4,110
Allowance for borrowed funds used during construction	(11,929)	(13,333)	(10,675)
Total interest charges	73,429	71,055	73,925
Income Before Income Taxes	204,138	123,351	151,347
Income Tax Expense (Benefit)	35,970	(41,399)	10,713
Net Income	$168,168	$164,750	$140,634

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Net Income	$168,168	$164,750	$140,634
Other Comprehensive Income:			
Net unrealized holding gains (losses) arising during the year, net of tax of $1,006, ($257), and $738	1,567	(400)	1,149
Unfunded pension liability adjustment, net of tax of ($4,532), ($1,062), and ($1,573)	(7,061)	(1,654)	(2,450)
Total Comprehensive Income	$162,674	$162,696	$139,333

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Consolidated Balance Sheets

	December 31, 2012	2011
	(thousands of dollars)	
Assets		
Electric Plant:		
In service (at original cost)	$4,915,772	$4,466,873
Accumulated provision for depreciation	(1,703,159)	(1,677,609)
In service - net	3,212,613	2,789,264
Construction work in progress	298,470	591,475
Held for future use	7,101	6,974
Electric plant - net	3,518,184	3,387,713
Investments and Other Property	128,145	128,674
Current Assets:		
Cash and cash equivalents	17,251	19,316
Receivables:		
Customer (net of allowance of $1,551 and $1,239, respectively)	66,111	66,296
Other (net of allowance of $322 and $196, respectively)	20,618	8,011
Income taxes receivable	2,559	4,644
Accrued unbilled revenues	51,448	46,441
Materials and supplies (at average cost)	51,037	46,490
Fuel stock (at average cost)	42,388	47,865
Prepayments	12,688	12,274
Deferred income taxes	48,774	14,099
Current regulatory assets	30,078	34,279
Other	4,950	4,606
Total current assets	347,902	304,321
Deferred Debits:		
American Falls and Milner water rights	17,909	20,015
Company-owned life insurance	22,646	24,060
Regulatory assets	1,132,960	953,068
Other	47,965	38,988
Total deferred debits	1,221,480	1,036,131
Total	$5,215,711	$4,856,839

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Consolidated Balance Sheets

	December 31, 2012	2011
	(thousands of dollars)	
Capitalization and Liabilities		
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	712,258	704,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	834,732	735,304
Accumulated other comprehensive loss	(17,116)	(11,622)
Total common stock equity	1,625,654	1,524,220
Long-term debt	1,466,632	1,387,550
Total capitalization	3,092,286	2,911,770
Current Liabilities:		
Long-term debt due within one year	71,064	101,064
Accounts payable	89,651	81,054
Accounts payable to related parties	252	1,512
Interest accrued	22,311	21,797
Accrued compensation	42,282	39,670
Current regulatory liabilities	30,277	29,738
Other	23,813	38,777
Total current liabilities	279,650	313,612
Deferred Credits:		
Deferred income taxes	1,001,877	863,044
Regulatory liabilities	355,362	332,057
Pension and other postretirement benefits	423,409	363,209
Other	63,127	73,147
Total deferred credits	1,843,775	1,631,457
Commitments and Contingencies		
Total	$5,215,711	$4,856,839

The accompanying notes are an integral part of these statements.

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Idaho Power Company
Consolidated Statements of Cash Flows

	Year ended December 31,		
	2012	2011	2010
	(thousands of dollars)		
Operating Activities:			
Net income	$168,168	$164,750	$140,634
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	128,009	124,028	121,219
Deferred income taxes and investment tax credits	48,255	(57,929)	78,631
Changes in regulatory assets and liabilities	(53,467)	68,045	46,509
Pension and postretirement benefit plan expense	45,230	45,223	14,728
Contributions to pension and postretirement benefit plans	(47,695)	(22,088)	(65,601)
Earnings of unconsolidated equity-method investments	(9,412)	(9,018)	(11,281)
Distributions from unconsolidated equity-method investments	17,921	—	4,755
Allowance for equity funds used during construction	(22,433)	(25,484)	(16,551)
Other non-cash adjustments to net income, net	236	1,159	(576)
Change in:			
Accounts receivables and prepayments	(4,519)	(2,468)	13,118
Accounts payable	10,762	5,357	4,080
Taxes accrued/receivable	3,301	19,217	(9,392)
Other current assets	(4,077)	(19,684)	3,848
Other current liabilities	(8,506)	2,169	13,674
Other assets	(7,064)	4,330	(3,662)
Other liabilities	(6,856)	(5,117)	(3,711)
Net cash provided by operating activities	257,853	292,490	330,422
Investing Activities:			
Additions to utility plant	(239,761)	(337,765)	(338,252)
Proceeds from the sale of utility assets	—	—	18,982
Proceeds from the sale of emission allowances and RECs	2,739	6,314	6,408
Investments in unconsolidated affiliates	—	(2,645)	—
Purchase of available for sale securities	(7,000)	—	(7,000)
Other	367	2,665	4,366
Net cash used in investing activities	(243,655)	(331,431)	(315,496)
Financing Activities:			
Issuance of long-term debt	150,000	—	200,000
Retirement of long-term debt	(101,064)	(121,064)	(1,064)
Dividends on common stock	(68,740)	(59,705)	(58,070)
Capital contribution from parent	7,500	16,000	50,000
Other	(3,959)	(1,207)	(3,184)
Net cash (used in) provided by financing activities	(16,263)	(165,976)	187,682
Net (decrease) increase in cash and cash equivalents	(2,065)	(204,917)	202,608
Cash and cash equivalents at beginning of the year	19,316	224,233	21,625
Cash and cash equivalents at end of the year	$17,251	$19,316	$224,233
Supplemental Disclosure of Cash Flow Information:			
Cash (received) paid during the year for:			
Income taxes	$(14,558)	$(759)	$(57,378)
Interest (net of amount capitalized)	$70,447	$70,491	$67,868

Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$26,882	$26,331	$33,949

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,		
	2012	2011	2010
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$735,304	$630,259	$547,695
Net Income	168,168	164,750	140,634
Dividends on Common Stock	(68,740)	(59,705)	(58,070)
Retained Earnings, End of Year	$834,732	$735,304	$630,259

The accompanying notes are an integral part of these statements.

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IDACORP, INC. AND IDAHO POWER COMPANY
NOTES TO 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 (Idaho Power). Therefore, the Notes to the Consolidated Financial Statements apply to both IDACORP and Idaho Power. However, Idaho Power 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 Idaho Power. Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

IDACORP's other wholly-owned 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 Services Co. (IESCo), which is the former limited partner of, and current successor by merger to, IDACORP Energy L.P. (IE), a marketer of energy commodities that wound down operations in 2003.

Principles of Consolidation

IDACORP's and Idaho Power's consolidated financial statements include the accounts of each company, the subsidiaries that the companies control, and any variable interest entities (VIEs) for which the companies are the primary beneficiaries. Intercompany balances have been eliminated in consolidation. Investments in subsidiaries that the companies do not control and investments in VIEs for which the companies 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 of accounting.

The entities that IDACORP and Idaho Power consolidate consist primarily of the wholly-owned subsidiaries discussed above. In addition, IDACORP consolidates one VIE, Marysville Hydro Partners (Marysville), which is a joint venture owned 50 percent by Ida-West and 50 percent by Environmental Energy Company (EEC). At December 31, 2012, Marysville had approximately $20 million of assets, primarily a hydroelectric plant, and approximately $15 million of intercompany long-term debt, which is eliminated in consolidation. EEC has borrowed amounts from Ida-West to fund a portion of its required capital contributions to Marysville. The loans are payable from EEC's share of distributions and are secured by the stock of EEC and EEC's interest in Marysville. Ida-West is the primary beneficiary because the ownership of the intercompany note and the EEC note result in it controlling the entity. Creditors of Marysville have no recourse to the general credit of IDACORP and there are no other arrangements that could require IDACORP to provide financial support to Marysville or expose IDACORP to losses.

The BCC joint venture is also a VIE, but because the power to direct the activities that most significantly impact the economic performance of BCC is shared with the joint venture partner, the company is not the primary beneficiary. The carrying value of BCC was $94 million at December 31, 2012, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $66 million guarantee for mine reclamation costs, which is discussed further in Note 9.

IFS's investments in affordable housing and other real estate are also VIEs for which IDACORP is not the primary beneficiary. IFS's limited partnership interests range from 5 to 99 percent and were acquired between 1996 and 2010. As a limited partner, IFS does not control these entities and they are not consolidated. IFS’s maximum exposure to loss in these developments is limited to its net carrying value, which was $51 million at December 31, 2012.

Management Estimates

Management makes estimates and assumptions when preparing financial statements in conformity with generally accepted accounting principles (GAAP). These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, litigation, asset impairment, income taxes, unbilled revenues, and bad debt. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the

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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 Idaho Power 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

IDACORP's and Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would. In these instances, the amounts are deferred as regulatory assets or regulatory liabilities on the balance sheet and recorded on the income statement when recovered or returned 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. The effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and highly-liquid temporary investments that mature within 90 days of the date of acquisition.

Receivables and Allowance for Uncollectible Accounts

Customer receivables are recorded at the invoiced amounts and do not bear interest. A late payment fee of one percent may be assessed on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The allowance is reviewed periodically and adjusted based upon a combination of historical write-off experience, aging of accounts receivable, and an analysis of specific customer accounts. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off through a charge to the allowance and a credit to accounts receivable.

Other receivables, primarily notes receivable from business transactions, are also reviewed for impairment periodically, based upon transaction-specific facts. When it is probable that IDACORP or Idaho Power will be unable to collect all amounts due according to the contractual terms of the agreement, an allowance is established for the estimated uncollectible portion of the receivable and charged to income.

There were no impaired receivables without related allowances at December 31, 2012 and 2011. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

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 and natural gas markets. All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet unless they are designated as normal purchases and normal sales. Idaho Power's physical forward contracts are designated as normal purchases and normal sales with the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities. The objective of Idaho Power's risk management program is to mitigate the price risk associated with the purchase and sale of electricity and natural gas. Because of Idaho Power’s regulatory accounting mechanisms, Idaho Power records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Revenues

Operating revenues related to Idaho Power’s sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. Idaho Power collects franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement. Beginning in February 2009, Idaho Power is collecting in base rates a portion of the

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allowance for funds used during construction (AFUDC) related to its Hells Canyon Complex relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue but is instead recorded as a regulatory liability.

Property, Plant and Equipment and Depreciation

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

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.75 percent in 2012, 2.83 percent in 2011, and 2.84 percent in 2010.

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. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment must be recognized in the financial statements. There were no material impairments of these assets in 2012, 2011, or 2010.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, as discussed above for the Hells Canyon Complex relicensing project, cash is not realized currently from such allowance; it is realized under the ratemaking 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 AFUDC attributable to borrowed funds is included as a reduction to total interest expense. Idaho Power’s weighted-average monthly AFUDC rates for 2012, 2011, and 2010 were 7.7 percent, 7.8 percent, and 8.0 percent, respectively.

Income Taxes

IDACORP and Idaho Power account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method (commonly referred to as normalized accounting), deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. In general, deferred income tax expense or benefit for a reporting period is recognized as the change in deferred tax assets and liabilities at the beginning and end of the period. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date unless Idaho Power's primary regulator, the Idaho Public Utilities Commission (IPUC), orders direct deferral of the effect of the change in tax rates over a longer period of time.

Consistent with orders and directives of the IPUC, unless contrary to applicable income tax guidance, Idaho Power does not provide deferred income taxes for certain income tax temporary differences and instead recognizes the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, Idaho Power's effective income tax rate is impacted as these differences arise and reverse. 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.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes are provided for other temporary differences unless accounted for using flow-through.

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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.

Income taxes are discussed in more detail in Note 2.

Comprehensive Income

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to a deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan. The following table presents IDACORP’s and Idaho Power’s accumulated other comprehensive loss balance at December 31 (net of tax):

	2012	2011
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$4,136	$2,569
Senior Management Security Plan	(21,252)	(14,191)
Total	$(17,116)	$(11,622)

Other Accounting Policies

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

Reclassifications

Certain prior year amounts on the IDACORP consolidated statements of income have been reclassified to conform to the current year presentation. In the current year, the allowance for equity funds used during construction has been classified to a separate line item. Previously, such amounts had been classified within the line item captioned "Other Income, Net." In addition, the components of the line item "Other interest, net of AFUDC" have been expanded to present a separate line item for the portion attributable to the allowance for borrowed funds used during construction. See also Note 18 concerning a corrective reclassification made to certain 2011 and 2010 operating expenses.

To conform with IDACORP's and Idaho Power's 2012 consolidated balance sheet presentation, certain employee compensation liabilities as of December 31, 2011, have been reclassified from "Accounts payable" and "Other" current liabilities and are now reported in the accompanying 2011 consolidated balance sheet in a separate line item captioned "Accrued compensation."

Previously reported net income, cash flows, and shareholders' equity were not affected by these reclassifications.

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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			Idaho Power		
	2012	2011	2010	2012	2011	2010
	(thousands of dollars)					
Federal income tax expense at 35% statutory rate	$68,206	$40,096	$49,723	$71,448	$43,173	$52,972
Change in taxes resulting from:						
AFUDC	(12,027)	(13,586)	(9,529)	(12,027)	(13,586)	(9,529)
Capitalized interest	5,075	6,465	3,674	5,075	6,465	3,674
Investment tax credits	(3,267)	(3,355)	(3,378)	(3,267)	(3,355)	(3,378)
Removal costs	(2,697)	(2,244)	(2,850)	(2,697)	(2,244)	(2,850)
Capitalized overhead costs	(8,750)	(5,950)	(3,500)	(8,750)	(5,950)	(3,500)
Capitalized repair costs	(19,250)	(14,000)	(10,500)	(19,250)	(14,000)	(10,500)
Tax method change – uniform capitalization	—	—	(65,333)	—	—	(65,333)
Tax method change – capitalized repairs	(7,845)	—	(44,466)	(7,845)	—	(44,466)
Uncertain tax positions – established	—	—	74,436	—	—	74,436
Uncertain tax positions – settled	—	(63,138)	(1,138)	—	(63,138)	(1,138)
State income taxes, net of federal benefit	7,503	1,375	4,565	7,646	1,846	5,074
Depreciation	14,398	14,100	13,138	14,398	14,100	13,138
Affordable housing tax credits	(5,493)	(6,438)	(7,309)	—	—	—
Other, net	(9,740)	(5,458)	1,736	(8,761)	(4,710)	2,113
Total income tax expense (benefit)	$26,113	$(52,133)	$(731)	$35,970	$(41,399)	$10,713
Effective tax rate	13.4%	(45.5)%	(0.5)%	17.6%	(33.6)%	7.1%

The items comprising income tax expense (benefit) are as follows:

	IDACORP			Idaho Power		
	2012	2011	2010	2012	2011	2010
	(thousands of dollars)					
Income taxes current:						
Federal	$547	$(10)	$(39,518)	$(13,131)	$9,234	$(62,338)
State	306	790	(5,960)	846	7,296	(5,580)
Total	853	780	(45,478)	(12,285)	16,530	(67,918)
Income taxes deferred:						
Federal	26,026	23,940	(22,582)	48,839	24,559	10,902
State	(9,822)	(1,285)	(4,436)	(9,640)	(6,920)	(4,036)
Total	16,204	22,655	(27,018)	39,199	17,639	6,866
Uncertain tax positions:						
Federal	—	(66,225)	65,222	—	(66,225)	65,222
State	—	(8,211)	8,076	—	(8,211)	8,076
Total	—	(74,436)	73,298	—	(74,436)	73,298
Investment tax credits:						
Deferred	12,323	2,223	1,845	12,323	2,223	1,845
Restored	(3,267)	(3,355)	(3,378)	(3,267)	(3,355)	(3,378)
Total	9,056	(1,132)	(1,533)	9,056	(1,132)	(1,533)
Total income tax expense (benefit)	$26,113	$(52,133)	$(731)	$35,970	$(41,399)	$10,713

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

	IDACORP		Idaho Power	
	2012	2011	2012	2011
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$55,085	$45,473	$55,085	$45,473
Advances for construction	3,010	5,118	3,010	5,118
Deferred compensation	23,556	22,172	23,463	22,067
Advanced payments	17,856	12,958	17,856	12,958
Power cost adjustments	—	1,711	—	1,711
Tax credits	145,710	119,310	21,217	8,571
Net operating losses	53,254	—	47,351	—
Revenue sharing	2,796	10,594	2,796	10,594
Retirement benefits	146,546	122,445	146,546	122,445
Other	5,834	5,380	4,340	3,758
Total	453,647	345,161	321,664	232,695
Deferred tax liabilities:				
Property, plant and equipment	406,283	333,335	406,283	333,335
Regulatory assets	677,795	599,992	677,795	599,992
Conservation programs	5,114	3,464	5,114	3,464
Power cost adjustments	16,832	—	16,832	—
Fixed cost adjustment	5,246	5,652	5,246	5,652
Partnership investments	19,178	19,749	7,970	6,181
Retirement benefits	142,270	122,712	142,270	122,712
Other	19,013	16,145	13,257	10,304
Total	1,291,731	1,101,049	1,274,767	1,081,640
Net deferred tax liabilities	$838,084	$755,888	$953,103	$848,945

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. See Note 1 for further discussion of accounting policies related to income taxes.

Tax Credit Carryforwards and Net Operating Loss Carryforwards

As of December 31, 2012, IDACORP had $107 million of general business credit and $1 million of alternative minimum tax credit carryforwards for federal income tax purposes and $38 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2024 to 2032, and the Idaho investment tax credit expires from 2019 to 2026. IDACORP has a $156 million federal net operating loss carryforward with expiration periods from 2031 to 2032.

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Uncertain Tax Positions

A reconciliation of the beginning and ending amount of unrecognized tax benefits for IDACORP and Idaho Power is as follows (in thousands of dollars):

	2012	2011	2010
Balance at January 1,	$—	$74,436	$1,138
Additions for tax positions of the current year	—	—	2,822
Additions for tax positions of prior years	—	—	71,614
Reductions for tax positions of prior years	—	(66,379)	(1,138)
Settlements with taxing authorities	—	(8,057)	—
Balance at December 31,	$—	$—	$74,436

IDACORP and Idaho Power recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Both companies recognized no interest expense in 2012, a net reduction of $0.2 million in 2011, and $0.2 million of interest expense in 2010. Accrued interest at both companies was zero as of December 31, 2012 and 2011, and $0.2 million as of December 31, 2010. No penalties are accrued.

IDACORP and Idaho Power are subject to examination by their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2012 for federal and 2009-2012 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items. In 2012, the IRS completed its examination of IDACORP's 2011 tax year with no unresolved income tax issues. IDACORP and Idaho Power believe there are no material tax uncertainties for 2012 and prior tax years.

Tax Accounting Method Change for Repair-Related Expenditures

In June 2010, Idaho Power completed its evaluation of a tax accounting method change for its 2009 tax year that allows a current income tax deduction for repair-related expenditures on its utility assets that are currently capitalized for financial reporting and tax purposes. In September 2010, Idaho Power adopted this method following the automatic consent procedures with the filing of IDACORP's 2009 consolidated federal income tax return. The method was subject to audit under IDACORP's 2009 CAP examination.

For the year ended December 31, 2010, Idaho Power recorded a $44.5 million tax benefit related to the filed deduction for the cumulative method change adjustment and an additional $11.7 million tax benefit for the annual deduction estimate included in its 2010 income tax provision. As of December 31, 2010, Idaho Power had a current uncertain tax position liability of $14.7 million related to this method.

In April 2011, IDACORP and the IRS reached an agreement on Idaho Power's tax accounting method change for capitalized repairs. Accordingly, the IRS finalized the 2009 CAP examination and submitted its report on the 2009 tax year to the U.S. Congress Joint Committee on Taxation (Joint Committee) for review. The capitalized repairs method is effectively settled and no material income tax uncertainties remain for the method. As such, Idaho Power recognized $3.4 million of its previously unrecognized tax benefits for this method in 2011.

In the third quarter of 2012 Idaho Power completed an income tax accounting method change for its 2011 tax year related to a portion of the capitalized repairs method. The change was made pursuant to Revenue Procedure 2011-43 to bring Idaho Power's existing method into alignment with the Revenue Procedure's safe harbor unit-of-property definitions for electric transmission and distribution property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP's 2011 consolidated federal income tax return. The IRS approved the method change prior to the filing of the return as part of IDACORP's 2011 CAP examination. A $7.8 million tax benefit was recognized in 2012 for the filed deduction related to the cumulative method change adjustment for years prior to 2011.

For the year ended December 31, 2012, the capitalized repairs annual tax deduction estimate included in Idaho Power's income tax provision produced a $21.5 million tax benefit (federal and state). The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. Idaho Power's primary regulator, the IPUC, requires flow-through accounting for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

Tax Accounting Method Change for Uniform Capitalization

In September 2009, the IRS issued Industry Director Directive #5 (IDD), which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. Within IDACORP's 2009 CAP examination, the IRS and Idaho Power worked through the impact the IDD guidance had on Idaho Power's uniform capitalization method and reached agreement during 2010. The agreement provided that Idaho Power change its uniform capitalization method to the agreed upon method under the IDD with the filing of IDACORP's 2009 consolidated federal income tax return. While Idaho Power had an agreement with the IRS for examination and return filing purposes, the agreement required Joint Committee approval to be final.

The resulting tax deductions available under the agreed upon uniform capitalization method were significantly greater than Idaho Power's prior method. For the year ended December 31, 2010, Idaho Power recorded a tax benefit of $65.3 million related to the cumulative method change adjustment (tax years 1986 through 2009) for this method and $5.6 million of tax expense from the reversal of this temporary difference. As of December 31, 2010, Idaho Power had a current uncertain tax position liability equal to the $59.7 million net tax benefit recorded for the method change. Due to the method change agreement with the IRS, Idaho Power reversed the uncertain tax position liability for its 2009 uniform capitalization deduction, resulting in a $1.1 million tax benefit for the year ended December 31, 2010.

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review of IDACORP's 2009 tax year and approved the uniform capitalization method agreement. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized the remaining $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

For the year ended December 31, 2012, the uniform capitalization annual tax deduction estimate included in Idaho Power's income tax provision produced a $9.8 million tax benefit (federal and state). The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. Idaho Power's primary regulator, the IPUC, requires flow-through accounting for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

Cash Impacts of Tax Method Changes

In 2011, IDACORP and Idaho Power paid previously accrued income tax liabilities of $3.9 million and $8.1 million, respectively, related to the capitalized repairs examination agreement. The difference in liabilities is primarily due to IDACORP's utilization of deferred federal general business tax credits. There were no 2011 cash impacts related to the uniform capitalization method settlement as income tax refunds for the method change were received in 2010.

In 2010, IDACORP and Idaho Power realized federal and state cash benefits associated with the 2009 capitalized repairs and uniform capitalization method changes of $33 million and $42 million, respectively. The majority of this cash benefit was realized through reductions to cash payments that would have otherwise been owed to taxing authorities for the 2009 tax year and a federal refund of $24 million received in 2010. Additionally, approximately $6 million of state cash benefits were realized through reduced tax payments for the 2010 year.

The capitalized repairs and uniform capitalization method changes produced an income statement tax benefit of $45 million and $65 million, respectively, in 2010 prior to the accrual for uncertain tax positions. A portion of this earnings benefit related to previously deferred income tax expense being flowed through the income statement, which does not deliver any cash benefits. In addition, federal tax credits of $17 million previously recognized were restored due to the reduction of 2009 taxable income by the two method changes. The restored credits were a reduction to cash received in 2010, but will be available to deliver cash benefits in future periods.

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3. REGULATORY MATTERS

As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies, including the prices that Idaho Power is authorized to charge for its electric service. These approvals are a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition.

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. Regulatory liabilities represent obligations to make refunds to customers for previous collections, except for cost of removal (which represents the cost of removing future electric assets). The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

Description	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	Total as of December 31, 2012	2011
Regulatory Assets:					
Income taxes		$—	$677,795	$677,795	$603,772
Unfunded postretirement benefits[2]		—	308,850	308,850	262,503
Pension expense deferrals[3]		50,036	14,959	64,995	58,044
Energy efficiency program costs[3]		17,085	—	17,085	15,956
Power supply costs[3]	Varies	60,680	—	60,680	8,490
Fixed cost adjustment[3]	2013-2014	13,418	—	13,418	14,457
Asset retirement obligations[4]		—	15,411	15,411	15,557
Mark-to-market liabilities[5]		—	1,055	1,055	4,707
Other	2013-2021	1,202	2,547	3,749	3,861
Total		$142,421	$1,020,617	$1,163,038	$987,347
Regulatory Liabilities:					
Income taxes		$—	$55,085	$55,085	$49,253
Removal costs[4]		—	168,651	168,651	163,173
Investment tax credits		—	79,897	79,897	70,841
Deferred revenue-AFUDC [3]		29,404	16,269	45,673	33,145
Energy efficiency program costs[3]		4,130	—	4,130	—
Power supply costs [3]	Varies	17,778	—	17,778	13,121
Settlement agreement sharing mechanism[3]	2013-2014	7,151	—	7,151	27,099
Mark-to-market assets[5]		—	4,579	4,579	3,754
Other		2,439	256	2,695	1,409
Total		$60,902	$324,737	$385,639	$361,795

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.
(2) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11.
(3) These items are discussed in more detail in this Note 3.
(4) Asset retirement obligations and removal costs are discussed in Note 13.
(5) Mark-to-market assets and liabilities are discussed in Note 16.

Idaho Power’s regulatory assets and liabilities are amortized over the period in which they are reflected in customer rates. In the event that recovery of Idaho Power’s costs through rates becomes unlikely or uncertain, regulatory accounting would no longer apply to some or all of Idaho Power’s operations and the items above may represent stranded investments. If not allowed full recovery of these items, Idaho Power would be required to write off the applicable portion, which could have a significant financial impact.

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Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

In both its Idaho and Oregon jurisdictions, Idaho Power's power cost adjustment (PCA) mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The PCA mechanisms compare Idaho Power's actual and forecast net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs currently being recovered in retail rates. Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs included in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund through retail rates. The power supply costs deferred primarily result from changes in wholesale market prices and transaction volumes, changes in contracted power purchase prices and volumes (including PURPA power purchases), and the levels of hydroelectric and thermal generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustments consist of (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and (b) a true-up component, based on the difference between the previous year’s actual net power supply costs and the previous year’s forecast. The latter component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The Idaho PCA mechanism also includes:

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exception of expenses associated with PURPA power purchases, which are allocated 100 percent to customers;
- a load change adjustment rate (LCAR), which is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns; and
- third-party transmission expenses (paid to third parties to facilitate wholesale purchases and sales of energy) as a component of net power supply costs for purposes of calculating the PCA.

The table below summarizes Idaho PCA rate adjustments during each of the years ended December 31, 2012, 2011, and 2010.

Effective Date	$ Change (millions)	Notes
June 1, 2012	$43.0	The PCA rate increase was offset by $27.1 million to be shared with customers pursuant to the revenue sharing order described below, resulting in a net rate increase of $15.9 million for these orders.
June 1, 2011	$(40.4)	The reduction to Idaho PCA rates was net of $10.0 million of Idaho Power’s energy efficiency rider deferral balance that the IPUC authorized for recovery in Idaho Power’s Idaho PCA rates.
June 1, 2010	$(146.9)	The IPUC’s order was made in conjunction with a January 2010 rate settlement agreement described below. Concurrent with the PCA rate decrease, the IPUC authorized an $88.7 million increase in base rates, $63.7 million of which was related to power supply costs.

Oregon Jurisdiction Power Cost Adjustment Mechanism: Idaho Power’s power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual return on equity (ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that Idaho Power's actual ROE for that year is no less than 100 basis points above Idaho Power's last authorized ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of the three years ended December 31, 2012, 2011, and 2010 are summarized in the table that follows.

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Year and Mechanism	APCU or PCAM Adjustment
2012 PCAM	Idaho Power estimates that actual net power supply costs were within the deadband, which would result in no deferral.
2012 APCU	A rate increase of $1.8 million annually took effect June 1, 2012.
2011 PCAM	Actual net power supply costs were below the deadband, which would have resulted in a $1.5 million deferral. However, Oregon-jurisdiction earnings were below the ROE threshold described above, resulting in no deferral.
2011 APCU	A rate decrease of $2.2 million annually took effect June 1, 2011.
2010 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2010 APCU	A rate increase of $2.6 million annually took effect June 1, 2010.

Idaho Regulatory Matters

2011 Idaho General Rate Case Settlement: On June 1, 2011, Idaho Power filed a general rate case with the IPUC requesting approximately $82.6 million in additional Idaho jurisdiction annual revenues through base rates. On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case, and on December 30, 2011 the IPUC issued an order approving the settlement stipulation. The settlement stipulation approved by the December 2011 order provided for a 7.86 percent authorized rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues, effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity and did not impose a moratorium on Idaho Power's filing a general rate case at a future date.

In addition to a base rate increase, the settlement stipulation addressed Idaho Power's calculation of the load change adjustment rate (LCAR) to be applied in Idaho Power's PCA mechanism. The LCAR is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The LCAR adjusts power supply cost recovery within the Idaho-jurisdiction PCA formula upwards or downwards for differences between actual load and the load used in calculating base rates. The settlement stipulation provided for a LCAR of $18.16 per megawatt-hour, effective January 1, 2012, compared to the rate of $19.67 per megawatt-hour in effect prior to that date.

January 2010 Idaho Settlement Agreement: In January 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power’s customers, the IPUC Staff, and other interested parties. Significant elements of the settlement agreement included:

- a specified distribution of the reduction in 2010 PCA that would reduce customer rates, provide up to a $25 million general increase in annual base rates, and reset base power supply costs for the PCA, effective with the June 1, 2010 PCA rate change;
- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent return on equity in any calendar year from 2009 to 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho-jurisdiction rate of return on year-end equity (Idaho ROE) is below 9.5 percent in any calendar year from 2009 to 2011. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more than $15 million in any one year unless there is a carryover. Carryover amounts were added to the $15 million annual allowance up to a maximum amortization of $25 million in any one year.

In April 2010, Idaho Power filed its annual application with the IPUC to implement new PCA rates to be effective June 1, 2010 through May 31, 2011, and to change base rates, pursuant to the terms of the January 2010 Idaho settlement agreement. In May 2010, the IPUC issued its order approving a $146.9 million decrease in the PCA, along with a base rate increase of $88.7 million, effective June 1, 2010. The $88.7 million base rate increase reflects a $63.7 million increase in base power supply costs and a $25 million increase in base rates.

Because Idaho Power's actual Idaho ROE was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and amortization provisions of the January 2010 settlement agreement were not triggered. However, recognition of income tax benefits in 2011 had a significant impact on Idaho Power's actual Idaho ROE and contributed to the triggering of the sharing mechanism for 2011. In accordance with the terms of the settlement agreement, Idaho Power recorded a $27.1 million reduction in revenue and regulatory liability in 2011, reflecting 50 percent of Idaho Power's 2011 Idaho-jurisdiction earnings above a 10.5 percent Idaho ROE to be shared with Idaho customers.

December 2011 Idaho Settlement Agreement: The sharing and ADITC amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011. On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power extending, with modifications, some of the provisions of the January 2010 settlement agreement. The settlement stipulation provided that:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more than $25 million in 2012;
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho-jurisdiction earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA adjustment; and
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers as a reduction to the pension regulatory asset and 25 percent to Idaho Power.

The December 2011 settlement stipulation provides that the return on year-end equity thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be automatically adjusted prospectively in the event the IPUC approves a change to Idaho Power's authorized return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2015. The automatic adjustments would be as follows: (a) the 9.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 95 percent of the new authorized return on equity, (b) the 10.0 percent return on year-end equity trigger in the settlement stipulation would be re-established at the new authorized return on equity amount, and (c) the 10.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 105 percent of the new authorized return on equity.

In consideration of these terms, the December 2011 settlement stipulation further provided that Idaho Power would allocate to customers as a reduction to the pension regulatory asset 75 percent of Idaho Power's own share of 2011 Idaho jurisdictional earnings over a 10.5 percent Idaho ROE.

Revenue Sharing Under January 2010 and December 2011 Idaho Settlement Agreements: On May 31, 2012, the IPUC issued an order approving Idaho Power's request to share revenues under the January 2010 and December 2011 settlement agreements. Idaho Power recorded in 2011 a $27.1 million reduction to revenue for amounts to be refunded to customers and a $20.3 million pre-tax charge to pension expense and an associated decrease in deferred pension regulatory asset, representing the additional amount to be allocated to Idaho customers (reducing Idaho customers' future obligation). The refund is being applied to the PCA rates in effect from June 1, 2012 to May 31, 2013.

Idaho Power's 2012 Idaho ROE exceeded 10.5 percent, triggering the sharing mechanism of the December 2011 settlement stipulation. For 2012, Idaho Power recorded a $7.2 million provision against current revenues, to be refunded to customers through a future rate reduction, and an additional $14.6 million of pension expense, to benefit Idaho customers by reducing the amount of deferred pension expense that will be collected from customers in the future.

Fixed Cost Adjustment: The fixed cost adjustment (FCA) began as a pilot program for Idaho Power’s Idaho residential and small general service customers, with a term from 2007 through 2009. The FCA is designed to remove Idaho Power’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. The FCA is adjusted each year to collect, or refund, the difference between the allowed fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. In April 2010, the IPUC approved a two-year extension of the FCA pilot program, effective retroactive to January 1, 2010, through December 31, 2011, and in March 2012 the IPUC issued an order approving the FCA as a permanent program. The order also maintained the existing cap on the FCA of no more than 3 percent of base revenue, with any excess deferred for collection in a subsequent year. The IPUC noted in its order, however, that the FCA does not isolate or identify changes in cost recovery associated solely with Idaho Power's energy efficiency programs, and instead responds to all changes in load, and

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directed Idaho Power to file with the IPUC a proposal to adjust the FCA. On September 28, 2012, Idaho Power submitted a compliance filing and motion to the IPUC requesting that the IPUC approve the FCA methodology used during the pilot program, without change, or an alternative methodology proposed by Idaho Power. On January 31, 2013, the IPUC issued an order stating that the FCA will continue unchanged, but that the IPUC will continue to monitor the FCA results annually.

On May 8, 2012, the IPUC issued an order authorizing Idaho Power to increase its annual FCA collection to $10.3 million for the period from June 1, 2012 to May 31, 2013. The following table summarizes FCA rate adjustments since inception:

FCA Year	Period rates in effect	Annual Amount (in millions)
2011	June 1, 2012-May 31, 2013	$10.3
2010	June 1, 2011-May 31, 2012	$9.3
2009	June 1, 2010-May 31, 2011	$6.3
2008	June 1, 2009-May 31, 2010	$2.7

As of December 31, 2012, Idaho Power had a $13.4 million regulatory asset associated with the FCA.

Cost Recovery for Langley Gulch Power Plant: On March 2, 2012, Idaho Power filed an application with the IPUC requesting an increase in annual Idaho-jurisdiction base rates of $59.9 million for recovery of Idaho Power's investment and associated costs for the Langley Gulch power plant, which became commercially available on June 29, 2012. Idaho Power's application stated that its estimated investment in the plant through June 2012 was approximately $398 million. After the impact of depreciation, deferred income taxes, amounts currently included in rates, and an Idaho-jurisdictional cost allocation, Idaho Power's application requested a $336.7 million increase in Idaho-jurisdiction rate base. Idaho Power's requested base rate increase was based on an overall rate of return of 7.86 percent, as authorized by a prior IPUC order. On June 29, 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rates, effective July 1, 2012. The order also provided for a $335.9 million increase in Idaho rate base. Inclusion of the Langley Gulch power plant in Idaho Power's power supply portfolio also resulted in a change in Idaho Power's power supply cost assumptions. Accordingly, in the Langley Gulch order the IPUC also updated Idaho Power's LCAR to $17.64 per MWh, effective July 1, 2012.

Defined Benefit Pension Plan Contribution Recovery: Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2012, Idaho Power's deferral balance associated with the Idaho-jurisdiction was $62.9 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions. Idaho Power has made substantial contributions to its defined benefit pension plan in recent years. The single largest contribution occurred in September 2010, when Idaho Power elected to make a $60 million contribution to its defined benefit pension plan, rather than the minimum required funding amount. The amount contributed over the minimum required contribution was intended to bring the defined benefit pension plan to a more funded position, potentially reducing future required contributions and Pension Benefit Guaranty Corporation premiums. On March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power’s application, with new rates effective on June 1, 2011. In September 2011, Idaho Power contributed an additional $18.5 million to its defined benefit pension plan and during 2012 contributed $44.3 million.

The order issued by the IPUC pertaining to the December 2011 Idaho settlement agreement described above provided that Idaho Power's allocation to customers of 75 percent of Idaho Power's share of 2011 Idaho ROE over 10.5 percent would be in the form of a $20.3 million reduction to Idaho Power's pension regulatory asset to reduce the future customer obligation.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs. Typically, a majority of energy efficiency activities are funded through a rider mechanism on customer bills. Program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. In the 2012 PCA filing, $14.5 million of certain demand response program costs were shifted from the rider mechanism to the PCA mechanism, as these costs are closely related to and directly impact the other power supply costs collected through the PCA.

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On March 15, 2012, Idaho Power filed an application with the IPUC requesting an order designating Idaho Power's 2011 demand-side management expenditures of $42.6 million as prudently incurred. On October 22, 2012 and December 11, 2012, the IPUC issued orders approving as prudently incurred $42.5 million of demand-side management expenditures, and deferring a portion of Idaho Power's additional requested amount for further review. Of Idaho Power's 2011 demand-side management expenditures, approximately $36 million were funded through a rider mechanism on customer bills and approximately $7 million were recorded as a regulatory asset. As of December 31, 2012, the Idaho energy efficiency rider balance was a regulatory liability of $4.1 million. Idaho Power's previous application filed in March 2011, which was approved by the IPUC in August 2011, designated Idaho Power's 2010 Idaho energy efficiency rider expenditures of approximately $42 million as prudently incurred expenses. The IPUC also issued an order in November 2010 designating energy efficiency expenditures of $50.7 million incurred in 2008 and 2009 as prudently incurred and approved for ratemaking purposes.

On October 31, 2012, Idaho Power filed an application with the IPUC requesting authorization to begin amortization and collection of the 2011 portion of the regulatory asset associated with its custom efficiency program (a demand-side resources program) over a four-year period, equal to approximately $2.9 million per year, including a carrying charge. A decision of the IPUC is pending.

The December 2011 IPUC general rate case settlement order also reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date.

Cost Recovery for Cessation of Boardman Coal-Fired Operations: In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. The plan results in increased revenue requirements for Idaho Power related to accelerated depreciation expense, additional plant investments, and decommissioning costs. In response to an application filed by Idaho Power, on February 15, 2012 the IPUC issued an order accepting Idaho Power's regulatory accounting and cost recovery plan associated with the early plant shut-down and approving the establishment of a balancing account whereby incremental costs and benefits associated with the early shut-down will be tracked for recovery in a subsequent proceeding. On May 17, 2012, the IPUC issued an order approving a $1.5 million annual increase in Idaho-jurisdiction base rates, with new rates effective June 1, 2012. As of December 31, 2012, Idaho Power's net book value in the Boardman plant was $23.1 million.

Idaho Depreciation Rate Filings: Idaho Power's advanced metering infrastructure (AMI) project provides the means to automatically retrieve and store energy consumption information, eliminating manual meter reading expense. Commencing June 1, 2009, the IPUC approved a rate increase, coincident with a related increase in depreciation expense, allowing Idaho Power to recover the three-year accelerated depreciation of the existing non-AMI metering equipment and to begin earning a return on its AMI investment. On April 27, 2012, the IPUC approved Idaho Power's February 15, 2012 application requesting approval of a $10.6 million decrease in rates for specified customer classes, effective June 1, 2012, as a result of the removal of accelerated depreciation expense associated with non-AMI metering equipment.

In connection with a depreciation study authorized by Idaho Power and conducted by a third party, on February 15, 2012, Idaho Power filed an application with the IPUC seeking to institute revised depreciation rates for electric plant-in-service, based upon updated service life estimates and net salvage percentages for all plant assets, and adjust Idaho-jurisdiction base rates to reflect the revised depreciation rates. Idaho Power's application requested a $2.7 million increase in Idaho-jurisdiction base rates. On May 31, 2012, the IPUC issued an order approving a settlement stipulation agreed to by Idaho Power, the IPUC Staff, and a large industrial customer of Idaho Power, which provided for a $1.3 million annual decrease in Idaho-jurisdiction base rates, effective June 1, 2012.

Oregon Regulatory Matters

2011 Oregon General Rate Case: On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues and an authorized rate of return on equity of 10.5 percent, with an Oregon retail rate base of approximately $121.9 million. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolved all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The OPUC approved the settlement stipulation on February 23, 2012, which provided for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation were effective March 1, 2012. The OPUC is conducting a second phase of the proceedings to address the prudence of Idaho Power's pollution control investments at the Jim Bridger plant.

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Cost Recovery for Langley Gulch Power Plant: On March 9, 2012, Idaho Power filed an application with the OPUC requesting an annual increase in Oregon jurisdiction revenues of $3.0 million for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base. On September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates effective October 1, 2012.

Federal Regulatory Matters - Open Access Transmission Tariff Rates

In 2006, Idaho Power moved from a fixed rate to a formula rate for transmission service provided under its open access transmission tariff (OATT), which allows transmission rates to be updated annually based on financial and operational data Idaho Power files with the FERC. Idaho Power's OATT rates submitted to the FERC in Idaho Power's four most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate (per kW-year)[1]
October 1, 2012 to September 30, 2013	$21.32
October 1, 2011 to September 30, 2012	$19.79
October 1, 2010 to September 30, 2011	$19.60
October 1, 2009 to September 30, 2010	$15.83

[1] In September 2010, Idaho Power made corrections to its OATT rates for the period beginning October 1, 2007 through September 30, 2010, which resulted in the issuance of a $0.5 million refund to transmission customers.

Idaho Power's most recent OATT filing was based on a net annual transmission revenue requirement of $108.4 million.

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4. LONG-TERM DEBT

The following table summarizes IDACORP's and Idaho Power's long-term debt at December 31 (in thousands of dollars):

	2012	2011
First mortgage bonds:		
4.75% Series due 2012	$—	$100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50% Series Due 2020	130,000	130,000
3.40% Series Due 2020	100,000	100,000
2.95% Series Due 2022	75,000	—
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
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
4.30% Series due 2042	75,000	—
Total first mortgage bonds	1,345,000	1,295,000
Pollution control revenue bonds:		
5.15% Series due 2024[1]	49,800	49,800
5.25% Series due 2026[1]	116,300	116,300
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	5,318	6,382
Unamortized premium/discount - net	(2,967)	(3,113)
Total IDACORP and Idaho Power outstanding debt[2]	1,537,696	1,488,614
Current maturities of long-term debt	(71,064)	(101,064)
Total long-term debt	$1,466,632	$1,387,550

[1] Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2012 to $1.511 billion.
[2] At December 31, 2012 and 2011, the overall effective cost of Idaho Power's outstanding debt was 5.44 percent and 5.43 percent, respectively.

At December 31, 2012, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2013	2014	2015	2016	2017	Thereafter
$71,064	$1,064	$1,064	$1,064	$1,064	$1,465,343

IDACORP Long-Term Financing

As of December 31, 2012, IDACORP had approximately $539 million remaining on a shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) that can be used for the issuance of debt securities or

IDACORP common stock. Common stock is discussed further in Note 6.

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Idaho Power Long-Term Financing

In May 2010, Idaho Power registered with the SEC the issuance of up to $500 million of first mortgage bonds and debt securities. On June 17, 2010, Idaho Power entered into a selling agency agreement with ten banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds. In August 2010, Idaho Power issued $100 million of 3.40% first mortgage bonds, medium-term notes, Series I maturing in August 2020, and $100 million of 4.85% first mortgage bonds, medium-term notes, Series I maturing in August 2040. On April 13, 2012, Idaho Power issued $75 million of 2.95% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2022, and $75 million of 4.30% first mortgage bonds, medium-term notes, Series I, maturing on April 1, 2042. The first mortgage bonds were issued under Idaho Power's shelf registration statement. As a result of these issuances, as of December 31, 2012, $150 million remained on Idaho Power’s shelf registration for the issuance of first mortgage bonds and debt securities.

In May 2012, Idaho Power used a portion of the net proceeds of the April 2012 sale of first mortgage bonds, medium-term notes to effect the early redemption in full of its $100 million of 4.75% first mortgage bonds, medium-term notes due November 2012.

Mortgage: As of December 31, 2012, Idaho Power could issue under its Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R.G. Page, as Trustees (Stanley Burg, successor individual trustee) (Mortgage) approximately $1.4 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Mortgage.

The Mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority, or distinction. First mortgage bonds issued in the future will also be secured by the Mortgage. The lien of the indenture constitutes a first mortgage on all the properties of Idaho Power, 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 Idaho Power 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 Idaho Power 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 Idaho Power. The Mortgage requires Idaho Power to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement, or amortization of its properties. Idaho Power may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Mortgage for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 billion to $2.0 billion. The amount issuable is also restricted by property, earnings, and other provisions of the Mortgage and supplemental indentures to the Mortgage. Idaho Power may amend the Mortgage and increase this amount without consent of the holders of the first mortgage bonds. The Mortgage requires that Idaho Power's net earnings be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that Idaho Power 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.

5. NOTES PAYABLE

Credit Facilities

IDACORP and Idaho Power have $125 million and $300 million credit facilities, respectively, which may be used for general corporate purposes and commercial paper backup. IDACORP's credit facility consists of a revolving line of credit not to exceed the aggregate principal amount at any one time outstanding of $125 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $15 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million.

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IDACORP and Idaho Power have the right to request an increase in the aggregate principal amount of the facilities to $150 million and $450 million, respectively, in each case subject to certain conditions.

The IDACORP and Idaho Power credit facilities have similar terms and conditions. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under their respective facilities, the companies pay a facility fee on the commitment based on the respective company's credit rating for senior unsecured long-term debt securities. While the credit facilities provide for an original maturity date of October 26, 2016, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, in each case subject to certain conditions. On October 12, 2012, IDACORP and Idaho Power executed First Extension Agreements with each of the lenders, extending the maturity dates under both agreements to October 26, 2017.

At December 31, 2012, no amounts were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2012, Idaho Power had regulatory authority to incur up to $450 million principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and interest rates of IDACORP's and Idaho Power's short-term borrowings were as follows at December 31:

	IDACORP		Idaho Power		Total	
	2012	2011	2012	2011	2012	2011
Commercial paper balances:						
At the end of year	$69,700	$54,200	$—	$—	$69,700	$54,200
Average during the year	$57,947	$65,574	$3,578	$—	$61,525	$65,574
Weighted-average interest rate						
At the end of the year	0.50 %	0.47 %	— %	— %	0.50 %	0.47 %

6. COMMON STOCK

IDACORP Common Stock

The following table summarizes common stock transactions during the last three years and shares reserved at December 31, 2012:

	Shares issued			Shares reserved
	2012	2011	2010	December 31, 2012
Balance at beginning of year	49,964,172	49,419,452	47,925,882	
Continuous equity program	—	—	973,585	3,000,000
Dividend reinvestment and stock purchase plan	62,084	119,999	144,655	2,576,723
Employee savings plan	49,296	91,277	105,375	3,567,954
Long-term incentive and compensation plan	82,934	333,444	256,662	1,618,260
Restricted stock plan	—	—	13,293	256,154
Balance at end of year	50,158,486	49,964,172	49,419,452	

IDACORP enters into sales agency agreements as a means of selling its common stock from time to time pursuant to a continuous equity program. IDACORP's current sales agency agreement is with BNY Mellon Capital Markets, LLC. As of December 31, 2012, there were approximately 3 million shares remaining available to be sold under the current sales agency agreement. No shares were issued under the sales agency agreement in 2011 or 2012. IDACORP sold 973,585 shares in 2010 at an average price of $35.47.

Idaho Power Common Stock

In 2012, 2011, and 2010, IDACORP contributed $7.5 million, $16 million, and $50 million, respectively, of additional equity to Idaho Power. No additional shares of Idaho Power common stock were issued in exchange for the contributions.

Restrictions on Dividends

A covenant under IDACORP's credit facility and Idaho Power's credit facility requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. Idaho Power'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 violate the covenants in their respective credit facilities or Idaho Power's Revised Code of Conduct. At December 31, 2012, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $889 million and $794 million, respectively, at December 31, 2012. There are additional facility covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments; restrict the creation of certain liens; and prohibit entering into any agreements restricting dividend payments to the company from any material subsidiary. At December 31, 2012, IDACORP and Idaho Power were in compliance with all facility covenants.

Idaho Power's Revised Code of Conduct, approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. At December 31, 2012, Idaho Power's common equity capital was 51 percent of its total adjusted capital. Further, Idaho Power must obtain the approval of the OPUC before it may directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power's articles of incorporation also contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. As of the date of this report, Idaho Power has no shares of preferred stock outstanding.

In addition to contractual restrictions on the amount and payment of dividends, the Federal Power Act prohibits the payment of dividends from "capital accounts." The term "capital accounts" is undefined in the Federal Power Act but could be interpreted to limit the payment of dividends by Idaho Power to the amount of Idaho Power's retained earnings.

7. STOCK-BASED COMPENSATION

IDACORP has two share-based compensation plans -- 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.

The LTICP (for officers, key employees, and directors) permits the grant of nonqualified stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2012, the maximum number of shares available under the LTICP and RSP were 1,371,305 and 15,796, respectively.

Stock Awards: Restricted stock awards have three-year vesting periods and entitle the recipients to dividends and voting rights. Unvested shares are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of these awards is based on the closing market price of common stock on the grant date and is charged to compensation expense over the vesting period, based on the number of shares expected to vest.

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to the attainment of specific performance conditions over the three-year vesting period. Based on the level of attainment of the performance conditions, the final number of shares awarded can range from zero to 150 percent of the target award. Dividends are accrued during the vesting period and paid out based on the final number of shares awarded.

The performance awards are based on two equally-weighted 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 closing market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of these awards is charged to compensation expense over the requisite service period, based on the number of shares expected to vest. The fair value of the TSR portion is estimated using the market value at the date of grant and a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of these awards is charged to compensation expense over the requisite service period, provided the requisite service period is rendered, regardless of the level of TSR metric attained.

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

	IDACORP		Idaho Power	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2012	339,938	$ 26.40	337,183	$ 26.40
Shares granted	123,048	37.59	120,549	37.56
Shares forfeited	(2,098)	35.59	(2,098)	35.59
Shares vested	(140,150)	22.42	(138,923)	22.42
Nonvested shares at December 31, 2012	320,738	$ 32.36	316,711	$ 32.32

The total fair value of shares vested during the years ended December 31, 2012, 2011, and 2010 was $4.9 million, $4.1 million, and $3.3 million, respectively. At December 31, 2012, IDACORP had $4.8 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. Idaho Power's share of this amount was $4.7 million. These costs are expected to be recognized over a weighted-average period of 1.71 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2012, a total of 14,820 shares were awarded to directors at a grant date fair value of $40.48 per share. Directors elected to defer receipt of 7,410 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: No stock options have been granted since 2006. The remaining unexercised stock option awards were granted with exercise prices equal to the market value of the stock on the date of grant, with a term of 10 years from the grant date and a five-year vesting period. The fair value of each option was amortized into compensation expense using graded vesting and, as of December 31, 2012, all compensation costs have been recognized. IDACORP uses original issue and/or treasury shares to satisfy exercised options.

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

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (000s)
IDACORP				
Outstanding at December 31, 2011	27,806	$32.29	1.75	$281
Exercised	(8,600)	33.62		
Expired	(4,000)	39.50		
Outstanding at December 31, 2012	15,206	$29.64	1.45	$208
Vested and exercisable at December 31, 2012	15,206	$29.64	1.45	$208
Idaho Power				
Outstanding at December 31, 2011	9,456	$33.67	1.58	$83
Exercised	(1,500)	28.45		
Expired	(4,000)	39.50		
Outstanding at December 31, 2012	3,956	$29.75	2.05	$54
Vested and exercisable at December 31, 2012	3,956	$29.75	2.05	$54

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The following table presents information about options vested and exercised (in thousands of dollars):

	IDACORP			Idaho Power		
	2012	2011	2010	2012	2011	2010
Fair value of options vested	$—	$—	$110	$—	$—	$96
Intrinsic value of options exercised	74	884	1,491	36	535	1,475
Cash received from exercises	289	9,423	5,475	77	3,838	5,394
Tax benefits realized from exercises	29	345	583	14	209	577

Compensation Expense: 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 Idaho Power for those costs associated with Idaho Power's employees (in thousands of dollars):

	IDACORP			Idaho Power		
	2012	2011	2010	2012	2011	2010
Compensation cost	$4,696	$4,207	$3,706	$4,577	$4,082	$3,489
Income tax benefit	1,836	1,645	1,449	1,789	1,596	1,364

No equity compensation costs have been capitalized.

8. EARNINGS PER SHARE

The following table presents the computation of IDACORP's basic and diluted earnings per share (EPS) for the years ended December 31, 2012, 2011, and 2010 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2012	2011	2010
Numerator:			
Net income attributable to IDACORP, Inc.	$168,761	$166,693	$142,798
Denominator:			
Weighted-average common shares outstanding - basic	49,930	49,457	48,193
Effect of dilutive securities:			
Options	4	16	32
Restricted Stock	76	85	115
Weighted-average common shares outstanding - diluted	50,010	49,558	48,340
Basic earnings per share	$3.38	$3.37	$2.96
Diluted earnings per share	$3.37	$3.36	$2.95

The diluted EPS computation excludes 137,880 and 332,182 options for the years ended December 31, 2011 and 2010, respectively, because the options' exercise prices were greater than the average market price of the common stock during that year. No such options were required to be excluded from the December 31, 2012 calculation. In total, 15,206 options were outstanding at December 31, 2012, with expiration dates between 2014 and 2015.

9. COMMITMENTS

Purchase Obligations

At December 31, 2012, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2013	2014	2015	2016	2017	Thereafter
Cogeneration and power production	$170,939	$182,123	$187,151	$189,880	$188,734	$2,938,582

Power and transmission rights	6,408	5,035	4,320	3,992	2,840	4,743
Fuel	73,627	63,236	56,942	9,418	9,317	94,849

As of December 31, 2012, Idaho Power had 779 MW nameplate capacity of PURPA-related projects on-line, with an additional 52 MW nameplate capacity of projects projected to be on-line by the end of 2014. The power purchase contracts for these projects have terms ranging from one to 35 years. During 2012, Idaho Power purchased 1,961,208 megawatt-hours (MWh) from these projects at a cost of $118 million, resulting in a blended price of $59.98 per MWh. Idaho Power purchased 1,495,108 MWh at a cost of $90 million in 2011, and 910,429 MWh at a cost of $55 million in 2010.

In addition, Idaho Power has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees (in thousands of dollars):

	2013	2014	2015	2016	2017	Thereafter
Operating leases	$1,888	$2,116	$2,123	$1,243	$955	$15,741
Equipment, maintenance, and service agreements	35,233	9,483	5,464	4,277	4,484	21,176
FERC and other industry-related fees	13,789	11,066	11,066	7,472	7,472	37,361

IDACORP’s expense for operating leases was approximately $6.1 million in 2012, $5.3 million in 2011, and $3.4 million in 2010.

Guarantees

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $66 million at December 31, 2012, representing IERCo's one-third share of BCC's total reclamation obligation of $199 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. As of December 31, 2012, the value of the reclamation trust fund totaled $72 million. During 2012 the reclamation trust fund distributed approximately $20 million for reclamation activity costs associated with the BCC surface mine. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

IDACORP and Idaho Power enter into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. IDACORP and Idaho Power periodically evaluate the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2012, management believes the likelihood is remote that IDACORP or Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Neither IDACORP nor Idaho Power has recorded any liability on their respective consolidated balance sheets with respect to these indemnification obligations.

10. CONTINGENCIES

IDACORP and Idaho Power have in the past and expect in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described in this Note 10. Some of these claims, controversies, disputes, and other contingent matters involve litigation and regulatory or other contested proceedings. The ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, IDACORP and Idaho Power, as applicable, establish an accrual for legal proceedings when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. In such cases, there may be a possible exposure to loss in excess of any amounts accrued. IDACORP and Idaho Power monitor those matters for developments that could affect the likelihood of a loss and the accrued amount, if any, thereof, and adjust the amount as appropriate. If the loss contingency at issue is not both probable and reasonably estimable, IDACORP and Idaho Power do not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable. As of the date of this report, IDACORP's and Idaho Power's accruals for loss contingencies are not material to their financial statements as a whole; however, future accruals could be material in a given period. IDACORP's and Idaho Power's determination is based on currently available information, and estimates

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presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. As available information changes, the matters for which IDACORP and Idaho Power are able to estimate the loss may change, and the estimates themselves may change. For matters that affect Idaho Power's operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery through the ratemaking process of costs incurred.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit. Idaho Power and IESCo (as successor to IE) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of pending petitions and predict that these matters will not have a material adverse effect on IDACORP's or Idaho Power's results of operations or financial condition. However, the settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which involve potential claims for refunds from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. The FERC characterized these ripple claims as "speculative." However, the FERC refused to dismiss Idaho Power and IESCo from the proceedings in the Pacific Northwest and refused to approve a settlement that provided for waivers of all claims in those proceedings, despite only limited objections from two market participants. Idaho Power and IESCo have petitioned for review of the FERC's decision. Based on its evaluation of the merits of such claims and the inability to estimate any potential exposure should the claims ultimately have merit, Idaho Power and IESCo have no remaining amount accrued for financial statement purposes relating to the western energy proceedings. To the extent the availability of any ripple claims materializes, Idaho Power and IESCo will continue to vigorously defend their positions in the proceedings.

Water Rights - Snake River Basin Adjudication

Idaho Power holds water rights, acquired under applicable state law, for its hydroelectric projects. In addition, Idaho Power holds water rights for domestic, irrigation, commercial, and other necessary purposes related to project lands and other holdings within the states of Idaho and Oregon. Idaho Power's water rights for power generation are, to varying degrees, subordinated to future upstream appropriations for irrigation and other authorized consumptive uses. Over time, increased irrigation development and other consumptive uses within the Snake River watershed led to a reduction in flows of the Snake River. In the late 1970s and early 1980s these reduced flows resulted in a conflict between the exercise of Idaho Power's water rights at certain hydroelectric projects on the Snake River and upstream consumptive diversions. The Swan Falls Agreement, signed by Idaho Power and the State of Idaho on October 25, 1984, resolved the conflict and provided a level of protection for Idaho Power's hydropower water rights at specified projects on the Snake River through the establishment of minimum stream flows and an administrative process governing future development of water rights that may affect those minimum stream flows. In 1987, Congress enacted legislation directing the FERC to issue an order approving the Swan Falls settlement together with a finding that the agreement was neither inconsistent with the terms and conditions of Idaho Power's project licenses nor the Federal Power Act. The FERC entered an order implementing the legislation in March 1988.

The Swan Falls Agreement provided that the resolution and recognition of Idaho Power's water rights together with the State Water Plan provided a sound comprehensive plan for management of the Snake River watershed. The Swan Falls Agreement also recognized, however, that in order to effectively manage the waters of the Snake River basin, a general adjudication to determine the nature, extent, and priority of the rights of all water uses in the basin was necessary. Consistent with that recognition, in 1987 the State of Idaho initiated the Snake River Basin Adjudication (SRBA), and pursuant to the commencement order issued by the SRBA court that same year, all claimants to water rights within the basin were required to file water rights claims in the SRBA. Idaho Power has filed claims to its water rights and has been actively participating in the SRBA since its commencement. Questions concerning the effect of the Swan Falls Agreement on Idaho Power's water rights claims, including the nature and extent of the subordination of Idaho Power's rights to upstream uses, resulted in the filing of litigation in the SRBA in 2007 between Idaho Power and the State of Idaho. This litigation was resolved by the Framework Reaffirming the Swan Falls Settlement (Framework) signed by Idaho Power and the State of Idaho on March 25, 2009. In that Framework, the parties acknowledged that the effective management of Idaho's water resources remains critical to the public interest of the State of Idaho by sustaining economic growth, maintaining reasonable electric rates, protecting and preserving existing water rights, and protecting water quality and environmental values. The Framework further provided that the State of Idaho and Idaho Power would cooperate in exploring approaches to resolve issues of mutual concern relating to the management of Idaho's water resources. Idaho Power continues to work with the State of Idaho and other interested parties on these issues.

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One such issue involves the management of the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer in southeastern Idaho that is hydrologically connected to the Snake River. House Concurrent Resolution No. 28, adopted by the Idaho Legislature in 2007, directed the Idaho Water Resource Board to pursue the development of a comprehensive management plan for the ESPA, to include measures that would enhance aquifer levels, springs, and river flows on the eastern Snake River plain to the benefit of both agricultural development and hydropower generation. In May of 2007, the Idaho Water Resource Board appointed an advisory committee, charged with the responsibility of developing a management plan for the ESPA. Idaho Power was a member of that committee. In January 2009, the Idaho Water Resource Board, based on the committee's recommendations, adopted a Comprehensive Aquifer Management Plan (CAMP) for the ESPA. The Idaho Legislature approved the CAMP that same year. Idaho Power is a member of the CAMP Implementation Committee and continues to work with the Idaho Water Resource Board, other stakeholders, and the Idaho Legislature in exploring opportunities for implementation of the CAMP management plan.

Idaho Power also continues its active participation in the SRBA in seeking to ensure that its water rights are protected and that the operation of its hydroelectric projects is not adversely impacted. While Idaho Power cannot predict the outcome, as of the date of this report Idaho Power does not anticipate any material modification of its water rights as a result of the SRBA process.

Other Proceedings

IDACORP and Idaho Power are parties to legal claims and legal and regulatory actions and proceedings in the ordinary course of business that are in addition to those discussed above and, as noted above, records an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report the companies believe that resolution of those matters will not have a material adverse effect on their consolidated financial statements. Idaho Power is also actively monitoring various environmental regulations that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to determine the financial impact of these regulations but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

11. BENEFIT PLANS

Idaho Power sponsors defined benefit and other postretirement benefit plans that cover the majority of its employees. IDACORP also sponsors a defined contribution 401(k) employee savings plan and provides certain post-employment benefits.

Pension Plans

Idaho Power's pension plans include a noncontributory defined benefit pension plan (pension plan) and a nonqualified defined benefit plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). The benefits under these plans are based on years of service and the employee's final average earnings.

Idaho Power’s funding policy for its pension plan is to contribute 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. In 2012, 2011, and 2010 Idaho Power elected to contribute more than the minimum required amounts in order to bring the pension plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums.

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

	Pension Plan		SMSP	
	2012	2011	2012	2011
Change in benefit obligation:				
Benefit obligation at January 1	$655,439	$569,934	$65,043	$59,126
Service cost	25,571	20,478	2,151	1,950
Interest cost	31,489	30,322	3,218	3,094
Actuarial loss	77,328	55,535	13,335	4,251
Benefits paid	(22,135)	(20,830)	(3,232)	(3,378)
Benefit obligation at December 31	767,692	655,439	80,515	65,043
Change in plan assets:				
Fair value at January 1	390,081	397,003	—	—
Actual return on plan assets	48,616	(4,592)	—	—
Employer contributions	44,300	18,500	—	—
Benefits paid	(22,135)	(20,830)	—	—
Fair value at December 31	460,862	390,081	—	—
Funded status at end of year	$(306,830)	$(265,358)	$(80,515)	$(65,043)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$—	$—	$(3,651)	$(3,496)
Noncurrent liabilities	(306,830)	(265,358)	(76,864)	(61,547)
Net amount recognized	$(306,830)	$(265,358)	$(80,515)	$(65,043)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$291,966	$245,632	$33,605	$21,799
Prior service cost	989	1,335	1,289	1,502
Subtotal	292,955	246,967	34,894	23,301
Less amount recorded as regulatory asset	(292,955)	(246,967)	—	—
Net amount recognized in accumulated other comprehensive income	$—	$—	$34,894	$23,301
Accumulated benefit obligation	$640,330	$549,503	$72,288	$59,836

As a non-qualified plan, the SMSP has no plan assets. However, Idaho Power has a Rabbi trust designated to provide funding for SMSP obligations. The Rabbi trust holds investments in marketable securities and corporate-owned life insurance. These investments totaled approximately $50.4 million and $41.2 million at December 31, 2012 and 2011, respectively, and are reflected in Investments and Company-owned life insurance on the consolidated balance sheets.

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The table that follows shows the components of net periodic benefit cost for these plans (in thousands of dollars). For purposes of calculating the expected return on plan assets, the market-related value of assets is equal to the fair value of the assets.

	Pension Plan			SMSP		
	2012	2011	2010	2012	2011	2010
Service cost	$25,571	$20,478	$17,671	$2,151	$1,950	$1,541
Interest cost	31,489	30,322	29,119	3,218	3,094	3,004
Expected return on assets	(31,737)	(32,322)	(26,463)	—	—	—
Amortization of net loss	14,114	8,673	7,675	1,530	1,293	931
Amortization of prior service cost	347	519	650	212	242	233
Net periodic pension cost	39,784	27,670	28,652	7,111	6,579	5,709
Adjustments due to the effects of regulation[1]	(5,860)	6,662	(24,104)	—	—	—
Net periodic benefit cost recognized for financial reporting	$33,924	$34,332	$4,548	$7,111	$6,579	$5,709

[1] Net periodic benefit costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates. See Note 3 for information on Idaho Power's revenue sharing mechanism approved by the IPUC, which resulted in additional Idaho pension expense of $14.6 million and $20.3 million in 2012 and 2011, respectively.

The following table shows the components of other comprehensive income for the plans (in thousands of dollars):

	Pension Plan			SMSP		
	2012	2011	2010	2012	2011	2010
Actuarial loss during the year	$(60,448)	$(92,449)	$(19,334)	$(13,335)	$(4,251)	$(5,187)
Reclassification adjustments for:						
Amortization of net loss	14,114	8,673	7,675	1,530	1,293	931
Amortization of prior service cost	347	519	650	212	242	233
Adjustment for deferred tax effects	17,979	32,193	4,660	4,532	1,062	1,573
Adjustment due to the effects of regulation	28,008	51,064	6,349	—	—	—
Other comprehensive income recognized related to pension benefit plans	$—	$—	$—	$(7,061)	$(1,654)	$(2,450)

In 2013, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $20.4 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2012, relating to the pension plan and SMSP. This amount consists of $17.0 million of amortization of net loss and $0.4 million of amortization of prior service cost for the pension plan, and $2.8 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

The following table summarizes the expected future benefit payments of these plans (in thousands of dollars):

	2013	2014	2015	2016	2017	2018-2022
Pension Plan	$23,882	$25,591	$27,490	$29,729	$32,179	$199,630
SMSP	3,721	3,948	4,130	4,129	4,326	23,932

As of December 31, 2012, IDACORP's and Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2013. IDACORP and Idaho Power may elect to make discretionary contributions above the minimum funding requirements or at times earlier than the required dates.

Postretirement Benefits

Idaho Power maintains a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers all employees who were enrolled in the group plan at the time of retirement as well as their spouses and qualifying dependents. Retirees hired on or after January 1, 1999 have access to the standard medical option at full cost, with no contribution by Idaho Power. Benefits for employees who retire after December 31, 2002 are limited to a fixed amount, which has limited the growth of Idaho Power's future obligations under this plan.

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

	2012	2011
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$66,669	$68,048
Service cost	1,292	1,323
Interest cost	3,135	3,434
Actuarial loss (gain)	3,180	(2,850)
Benefits paid[1]	(1,729)	(2,968)
Plan amendments	—	(318)
Benefit obligation at December 31	72,547	66,669
Change in plan assets:		
Fair value of plan assets at January 1	31,901	33,176
Actual return on plan assets	3,346	1,065
Employer contributions[1]	(131)	628
Benefits paid[1]	(1,729)	(2,968)
Fair value of plan assets at December 31	33,387	31,901
Funded status at end of year (included in noncurrent liabilities)	$(39,160)	$(34,768)

[1] Contributions and benefits paid are each net of $3,268 and $3,405 of plan participant contributions, and $430 and $444 of Medicare Part D subsidy receipts for 2012 and 2011, respectively.

Amounts recognized in accumulated other comprehensive income consist of the following (in thousands of dollars):

	2012	2011
Net loss	$15,796	$14,112
Prior service cost (credit)	99	(323)
Transition obligation	—	2,040
Subtotal	15,895	15,829
Less amount recognized in regulatory assets	(15,895)	(15,536)
Less amount included in deferred tax assets	—	(293)
Net amount recognized in accumulated other comprehensive income	$—	$—

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

	2012	2011	2010
Service cost	$1,292	$1,323	$1,276
Interest cost	3,135	3,434	3,578
Expected return on plan assets	(2,234)	(2,641)	(2,503)
Amortization of net loss	384	577	562
Amortization of prior service cost	(422)	(421)	(482)
Amortization of unrecognized transition obligation	2,040	2,040	2,040
Net periodic postretirement benefit cost	$4,195	$4,312	$4,471

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The following table shows the components of other comprehensive income for the plan (in thousands of dollars):

	2012	2011	2010
Actuarial (loss) gain during the year	$(2,068)	$1,274	$(2,413)
Prior service cost arising during the year	—	318	(629)
Reclassification adjustments for:			
Amortization of net loss	384	577	562
Amortization of prior service cost	(422)	(421)	(482)
Amortization of unrecognized transition obligation	2,040	2,040	2,040
Adjustment for deferred tax effects	(153)	(1,659)	18
Adjustment due to the effects of regulation	219	(2,129)	904
Other comprehensive income related to postretirement benefit plans	$—	$—	$—

In 2013, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $0.6 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2012, relating to the postretirement benefit plan. This amount consists of $0.7 million of amortization of net loss and $(0.1) million of amortization of prior service cost.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law in December 2003 and established a prescription drug benefit under Medicare Part D, 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 following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2013	2014	2015	2016	2017	2018-2022
Expected benefit payments	$4,010	$4,180	$4,320	$4,430	$4,530	$23,420
Expected Medicare Part D subsidy receipts	480	520	560	620	670	4,360

Plan Assumptions

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

	Pension Plan		SMSP		Postretirement Benefits	
	2012	2011	2012	2011	2012	2011
Discount rate	4.20%	4.90%	4.15%	5.10%	4.20%	5.05%
Rate of compensation increase[(1)]	4.35%	4.35%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	6.5%	7.0%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2012	12/31/2011	12/31/2012	12/31/2011	12/31/2012	12/31/2011

(1) The 2012 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.60% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in their fortieth year of service and beyond.

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The following table sets forth the weighted-average assumptions used to determine net periodic benefit cost for all Idaho Power-sponsored pension and postretirement benefit plans:

	Pension Plan			SMSP			Postretirement Benefits		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
Discount rate	4.90 %	5.40 %	5.90 %	5.10 %	5.40 %	5.90 %	5.05 %	5.40 %	5.90 %
Expected long-term rate of return on assets	7.75 %	8.25 %	8.25 %	—	—	—	7.25 %	8.25 %	8.25 %
Rate of compensation increase	4.35 %	4.50 %	4.50 %	4.50 %	4.50 %	4.50 %	—	—	—
Medical trend rate	—	—	—	—	—	—	6.5 %	7.0 %	7.5 %
Dental trend rate	—	—	—	—	—	—	5.0 %	5.0 %	5.0 %

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.5 percent in 2012 and is assumed to decrease gradually to 4.9 percent by 2094. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent in 2012 and is assumed to decrease gradually to 4.9 percent by 2094. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2012 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	$343	$(255)
Effect on accumulated postretirement benefit obligation	3,482	(2,708)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2012 for the pension asset portfolio by asset class is set forth below.

Asset Class	Target Allocation	Actual Allocation December 31, 2012
Debt securities	24 %	24 %
Equity securities	54 %	55 %
Real estate	6 %	6 %
Other plan assets	16 %	15 %
Total	100 %	100 %

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

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

The three major goals in Idaho Power’s asset allocation process are to:

- 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. Idaho Power sets bond allocations sufficient to cover at least five years of benefit payments and cash allocations sufficient to cover the current year benefit payments. Idaho Power then utilizes growth instruments (equities, real estate, venture capital) to fund the longer-term liabilities of the plan; and

- 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.

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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.

Idaho Power'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.

Fair Value of Plan Assets: Idaho Power classifies its pension plan and postretirement benefit plan investments using the three-level fair value hierarchy described in Note 16. The following table presents the fair value of the plans' investments by asset category (in thousands of dollars). If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security.

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2012				
Pension assets:				
Cash and cash equivalents	$7,628	$—	$—	$7,628
Short-term bonds	—	12,373	—	12,373
Long-term bonds	—	96,671	—	96,671
Equity Securities: Large-Cap	57,526	—	—	57,526
Equity Securities: Mid-Cap	19,944	16,780	—	36,724
Equity Securities: Small-Cap	36,409	—	—	36,409
Equity Securities: Micro-Cap	19,923	—	—	19,923
Equity Securities: International	19,461	59,142	—	78,603
Equity Securities: Emerging Markets	3,101	21,370	—	24,471
Equity Securities: Market Neutral	7,675	—	—	7,675
Real estate	—	—	27,874	27,874
Private market investments	—	—	30,507	30,507
Commodities funds	1,420	23,058	—	24,478
Total pension assets	$173,087	$229,394	$58,381	$460,862
Postretirement assets(1)	$325	$33,062	$—	$33,387

(1) The postretirement benefits assets are primarily life insurance contracts.

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	Level 1	Level 2	Level 3	Total
Assets at December 31, 2011				
Pension assets:				
Cash and cash equivalents	$6,141	$—	$—	$6,141
Short-term bonds	—	23,443	—	23,443
Long-term bonds	—	74,658	—	74,658
Equity Securities: Large-Cap	51,780	—	—	51,780
Equity Securities: Mid-Cap	17,961	14,002	—	31,963
Equity Securities: Small-Cap	31,825	—	—	31,825
Equity Securities: Micro-Cap	16,087	—	—	16,087
Equity Securities: International	30,444	32,118	—	62,562
Equity Securities: Emerging Markets	1,745	15,112	—	16,857
Real estate	—	—	25,119	25,119
Private market investments	—	—	27,786	27,786
Commodities funds	2,929	18,931	—	21,860
Total pension assets	$158,912	$178,264	$52,905	$390,081
Postretirement assets(1)	$—	$31,901	$—	$31,901

(1) The postretirement benefits assets are primarily life insurance contracts.

The following table presents a reconciliation of the beginning and ending balances of the fair value measurements using significant unobservable inputs (Level 3):

	Private Equity	Real Estate	Total
Beginning balance - January 1, 2011	$29,932	$22,069	$52,001
Realized gains	—	598	598
Realized losses	(133)	—	(133)
Unrealized gains	1,425	1,854	3,279
Purchases, issuances, and settlements, net	(3,438)	598	(2,840)
Ending balance - December 31, 2011	27,786	25,119	52,905
Realized gains	95	742	837
Unrealized gains	1,387	1,271	2,658
Purchases	1,779	742	2,521
Sales	(540)	—	(540)
Ending balance - December 31, 2012	$30,507	$27,874	$58,381

Fair Value Measurement of Level 2 and Level 3 Plan Asset Inputs:

Level 2 Bonds, Equity Securities, and Level 2 Commodities: These investments represent U.S. government and agency bonds, corporate bonds, and commingled funds consisting of publicly traded equity securities or exchange-traded commodity contracts and other contractual claims to commodity holdings. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing quoted prices for similar assets or liabilities in active markets. The commingled funds themselves are not publicly traded, and therefore no publicly quoted market price is readily available. The value of these investments is calculated by the custodian for the fund company on a monthly basis, and is based on market prices of the assets held by the commingled fund divided by the number of fund shares outstanding.

Level 3 Real Estate: Real estate holdings represent investments in open-ended commingled real estate funds. As the property interests held in these real estate funds are not frequently traded, establishing the market value of the property interests held by the fund, and the resulting unit value of fund shareholders, is based on unobservable inputs including property appraisals by the fund company, property appraisals by independent appraisal firms, analysis of the replacement cost of the property, discounted cash flows generated by property rents and changes in property values, and comparisons with sale prices of similar properties in

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similar markets. These open-ended real estate funds also furnish annual audited financial statements that are also used to further validate the information provided.

Level 3 Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund company based on the estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some hedge fund strategies utilize securities with readily available market prices, while others utilize less liquid investment vehicles that are valued based on unobservable inputs including cost, operating results, recent funding activity, or comparisons with similar investment vehicles. Venture capital fund investments are valued by the fund company based on estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some venture capital investments have progressed to the point that they have readily available exchange-based market valuations. Early stage venture investments are valued based on unobservable inputs including cost, operating results, discounted cash flows, the price of recent funding events, or pending offers from other viable entities. These private market investments furnish annual audited financial statements that are also used to further validate the information provided.

The fair value of the Level 3 assets is determined based on pricing provided or reviewed by third-party vendors to our investment managers. While the input amounts used by the pricing vendors in determining fair value are not provided, and therefore unavailable for Idaho Power's review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar assets classes. Additionally, the audited financial statements of the funds are reviewed at the time they are issued.

There were no material changes in valuation techniques or inputs during the years ended December 31, 2012 and 2011.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and which covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were $7 million, $6 million, and $5 million in 2012, 2011, and 2010, respectively.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power’s disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IDACORP’s and Idaho Power’s consolidated balance sheets at December 31, 2012 and 2011 are $2.6 million and $3.8 million, respectively.

12. PROPERTY, PLANT AND EQUIPMENT AND JOINTLY-OWNED PROJECTS

The following table presents the major classifications of Idaho Power’s utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years 2012 and 2011 (in thousands of dollars):

	2012			2011		
	Balance	Avg Rate		Balance	Avg Rate	
Production	$2,217,334	2.36	%	$1,832,287	2.22	%

Transmission	931,403	2.02 %	871,784	2.06 %
Distribution	1,411,740	2.89 %	1,434,925	3.12 %
General and Other	355,295	6.47 %	327,877	7.32 %
Total in service	4,915,772	2.75 %	4,466,873	2.83 %
Accumulated provision for depreciation	(1,703,159)		(1,677,609)	
In service - net	$3,212,613		$2,789,264	

Idaho Power's ownership interest in three jointly-owned generating facilities is included in the table above. Under the joint operating agreements for these facilities, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of operating expenses are included in the Consolidated

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Statements of Income. These jointly-owned facilities, including balance sheet amounts and the extent of Idaho Power's participation, were as follows at December 31, 2012 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW [(1)]
Jim Bridger Units 1-4	Rock Springs, WY	$542,894	$16,528	$280,875	33	771
Boardman	Boardman, OR	79,031	1,355	55,940	10	64
Valmy Units 1 and 2	Winnemucca, NV	353,541	10,163	198,190	50	284

[(1)] Idaho Power's share of nameplate capacity.

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $75 million, $65 million, and $76 million in 2012, 2011, and 2010, respectively.

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $9 million, $9 million, and $8 million in 2012, 2011, and 2010, respectively.

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

13. ASSET RETIREMENT OBLIGATIONS (ARO)

The guidance relating to accounting for AROs requires that legal obligations associated with the retirement of property, plant and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under the guidance, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized. As a rate-regulated entity, Idaho Power records regulatory assets or liabilities instead of accretion, depreciation, and gains or losses, as approved by the IPUC. The regulatory assets recorded under this order do not earn a return on investment. Beginning June 1, 2012, accretion, depreciation, and gains or losses related to the Boardman generating facility have been exempted from such regulatory treatment as Idaho Power is now collecting amounts related to the decommissioning of Boardman in rates.

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyls-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly-owned coal-fired generation facilities. In 2012, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $1.4 million in the recorded AROs. The primary cause of the increase in the AROs in 2012 is an increased ARO for the Valmy generating facility evaporation pond as determined by a revised evaporation pond decommissioning study.

Idaho Power also has additional AROs associated with its transmission system, hydroelectric facilities, and jointly owned coal-fired generation facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the consolidated financial statements.

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the costs recorded as regulatory liabilities on IDACORP's and Idaho Power's Consolidated Balance Sheets as of December 31, 2012 and 2011.

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

	2012	2011
Balance at beginning of year	$21,367	$16,952
Accretion expense	984	936
Revisions in estimated cash flows	1,416	3,930
Liability settled	(785)	(451)
Balance at end of year	$22,982	$21,367

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14. INVESTMENTS

The table below summarizes IDACORP’s and Idaho Power’s investments as of December 31 (in thousands of dollars).

	2012	2011
Idaho Power investments:		
Equity method investment	$93,650	$102,158
Available-for-sale equity securities	31,913	22,205
Executive deferred compensation plan	2,478	3,439
Other investments	2	2